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Group I

Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the

STEAM ELECTRIC POWER GENERATING

Point Source Category

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

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DEVELOPMENT DOCUMENT

for

EFFLUENT LIMITATIONS GUIDELINES

and

NEW SOURCE PERFORMANCE STANDARDS

for the

STEAM ELECTRIC POWER GENERATING POINT SOURCE CATEGORY

Russell E. Train
Administrator

James L. Agee
Assistant Administrator for Water and Hazardous Materials

Allen Cywin, P.E.
Director, Effluent Guidelines Division

Dr. Charles R. Nichols, P.E.
Project Officer

October, 1974

Effluent Guidelines Division
Office of Water and Hazardous Materials
U.S. Environmental Protection Agency
Washington, D. C. 20460

ABSTRACT

This document presents the findings of an extensive study of the steam electric power generating point source category for the purpose of developing effluent limitations, guidelines, standards of performance for new sources, and pretreatment standards for the industry in compliance with and to implement Sections 304, 306 and 307 of the Federal Water Pollution Control Act Amendments of 1972.

Effluent limitations guidelines contained herein set forth as mandated by the "Act":

(1) The degree of effluent reduction attainable through the application of the "best practicable control technology currently available" which must be achieved by nonnew point sources by no later than July 1, 1977.

(2) The degree of effluent reduction attainable through the application of the "best available technology economically achievable" which must be achieved by nonnew point sources by no later than July 1, 1983.

The standards of performance for new sources contained herein set forth the degree of effluent reduction which is achievable through the application of the "best available demonstrated control technology, process, operating methods, or other alternatives."

This report contains findings, conclusions and recommendations on control and treatment technology relating to chemical wastes and thermal discharges from steam electric powerplants. Supporting data and rationale for development of the effluent limitations, guidelines and standards of performance are contained herein.

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SECTION I

CONCLUSIONS

For the purpose of establishing effluent limitations, guidelines and standards of performance for steam electric powerplants, it has been found that separate consideration must be given to effluent heat and to pollutants other than heat, and these are therefore discussed in separate parts of this report.

The framework for establishing limitations for pollutants other than heat (chemical-type wastes) has been based on the types of waste streams generated in each plant, which in turn are dependent on fuels used, processes employed, plant site characteristics and waste control technologies. Chemical-type wastes include wastes from the water treatment system, power cycle system, ash handling system, air pollution control system, coal pile, yard and floor drainage, condenser cooling system and miscellaneous wastes.

Significant factors for limitations for effluent heat (thermal discharges) are utilization, age, and size of facilities.

A survey of current industry practices has indicated that many plants provide only minimal treatment of chemical type wastes at the present time, although some of the more recently constructed plants employ elaborate re-use and recycle systems as a means of water management. Current industry practice as far as thermal discharges are concerned is that they have been successfully controlled where required by environmental considerations or at sites where the lack of sufficient naturally available cooling water made once-through cooling systems impractical.

Current treatment and control technology in the general field of waste treatment includes many processes which could be applied by powerplants to reduce the discharge of chemical pollutants. It is therefore concluded that best practicable control technology currently available to be applied no later than July 1, 1977, consists of the control and treatment of chemical-type wastes to achieve significant reductions in the level of pollutants discharged from existing sources. It is also concluded that best available technology economically achievable to be applied no later than July 1, 1983, for chemical-type wastes is reflected in addition by recycle of bottom ash transport water and by chemical treatment of cooling tower blowdown to remove chromium, phosphorus and zinc. Standards of performance for new sources will provide for essentially the same effluent levels as best available technology, however, limitations on cooling tower blowdown are based on design for corrosion prevention rather than the addition of chemicals for corrosion inhibition.

For thermal effluents, it is concluded that technology is currently available and is widely utilized in the industry to achieve any desired or necessary degree of reduction of the thermal component of powerplant discharges, including essentially the complete elimination of thermal discharges. The technological basis for best available technology economically achievable, and new source performance standards consists of closed-cycle evaporative cooling systems such as mechanical and natural draft cooling towers and cooling ponds, lakes and canals.

The designation of specific control and treatment as best practicable control technology currently available, best available technology economically achievable, or as the basis for new source standards for both chemical and thermal discharges is intended to satisfy sections 304 and 306 of the Act. Technology so designated provides the basis for establishment of thermal and chemical effluent limitations, guidelines and standards, in that the technology selected is available and capable of meeting the recommended limitations. However, the designation of specific technology as "best practicable", etc., does not mean that it alone must be utilized to meet the effluent limitations. Any technology capable of meeting the limitations may be employed by any powerplant so long as the effluent limitations are achieved.

SECTION II

RECOMMENDATIONS

As a result of the findings and conclusions contained in this report, the effluent limitations, guidelines and standards of performance recommended for the steam electric power generating point source category, in compliance with the mandates of the Federal Water Pollution Control Act Amendments of 1972, are summarized in Tables II-1 and II-2.

Table II-2

SUMMARY OF EFFLUENT LIMITATIONS GUIDELINES AND STANDARDS FOR HEAT

All no discharge limitations allow for blowdown to be discharged at a temperature not to exceed the cold-side temperature, except where a unit has existing closed-cycle cooling blowdown may exceed the cold-side temperature. All limitations for existing units to be achieved by no later than July 1, 1981, except where system reliability would be seriously impacted the compliance date can be extended to no later than July 1, 1983.

EXISTING GENERATING UNITS	
Capacity 500 Mw and greater	
Placed into service prior to January 1, 1970	NO LIMITATION*
Placed into service January 1, 1970 or thereafter	NO DISCHARGE
Capacity 25 Mw to 499 Mw	
Placed into service prior to January 1, 1974	NO LIMITATION*
Placed into service January 1, 1974 or thereafter	NO DISCHARGE
Capacity less than 25 Mw	NO LIMITATION
* Note: Exceptions prescribed on a case-by-case basis for units in systems of less than 150 Mw capacity, units with cooling ponds or cooling lakes, units without sufficient land available, units with blowdown TDS 30,000 mg/l or greater and neighboring land within 500 ft of cooling tower(s), and units where FAA finds a hazard to commercial aviation would exist.	
NEW SOURCES	NO DISCHARGE

Note: No effluent limitations on heat from sources other than main condenser cooling water

SECTION III

INTRODUCTION

General Background

The involvement of the Federal Government in water pollution control dates back to 1948, when Congress enacted the first comprehensive measure aimed specifically at this problem. At that time the Surgeon General, through the U. S. Public Health Service, was authorized to assist states in various ways to attack the problem. The emergence of a national water pollution control program came about with the enactment of the Water Pollution Control Act of 1956 (Public Law 84-660) which to this date remains the basic law governing water pollution. This law set up the basic system of technical and financial assistance to states and municipalities, and established enforcement procedures by which the Federal Government could initiate legal steps against polluters.

The present program dates back to the Water Quality Act of 1965 and the Clean Water Restoration Act of 1966. Under the 1965 Act, the states were required to adopt water quality standards for interstate waters, and to submit to the Federal Government, for approval, plans to implement and enforce these standards. The 1966 Act authorized massive Federal participation in the construction of sewage treatment plants. An amendment, the Water Quality Act of 1970, extended Federal activities into such areas as pollution by oil, hazardous substances, sewage from vessels, and mine drainage.

Originally, pollution control activities were the responsibility of the U. S. Public Health Service. In 1961, the Federal Water Pollution Control Administration (FWPCA) was created in the Department of Health, Education, and Welfare, and in 1966, the FWPCA was transferred to the Department of the Interior. The name was changed in early 1970 to the Federal Water Quality Administration and in December 1970, the Environmental Protection Agency (EPA) was created by Executive Order as an independent agency outside the Department of the Interior. Also by Executive Order 11574 on December 23, 1970, President Richard M. Nixon established the Permit Program, requiring all industries to obtain permits for the discharge of wastes into navigable waters or their tributaries under the provisions of the 1899 River and Harbor Act (Refuse Act). The permit program immediately became involved in legal problems resulting eventually in a ruling by a Federal court that effectively stopped the issuance of a significant number of permits, but it did result in the filing with EPA, through the U.S. Army Corps of Engineers, of applications for permits which, without doubt, represent the most complete inventory of industrial waste discharges yet compiled. The granting of a permit under the Refuse Act was dependent on the discharge being able to meet applicable water quality standards. Although EPA could not specify methods of treatment, they could require minimum effluent levels necessary to meet water quality standards.

The Federal Water Pollution Control Act Amendments of 1972 (the "Act") made a number of fundamental changes in the approach to achieving clean water. One of the most significant changes was from a reliance on water quantity related effluent limitations to a direct control of effluents through the establishment of technology-based effluent limitations to form an additional basis, as a minimum, for issuance of discharge permits. The permit program under the 1899 Refuse Act was placed under full control of EPA, with much of the responsibility to be delegated to the States.

Purpose and Authority

The Act requires the EPA to establish guidelines for technology-based effluent limitations which must be achieved by point sources of discharges into the navigable waters of the United States. Section 301(b) of the Act requires the achievement by not later than July 1, 1977, of effluent limitations for point sources, other than publicly owned treatment works, which are based on the application of the best practicable control technology currently available as defined by the Administrator pursuant to Section 304(b) of the Act. Section 301(b) also requires the achievement by not later than July 1, 1983, of effluent limitations for point sources, other than publicly owned treatment works, which are based on the application of the best available technology economically achievable which will result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants, as determined in accordance with regulations issued by the Administrator pursuant to Section 304(b) of the Act. Section 306 of the Act requires the achievement by new sources of a Federal standard of performance providing for the control of the discharge of pollutants which reflects the greatest degree of effluent reduction which the Administrator determines to be achievable through the application of the best available demonstrated control technology, processes, operating methods, or other alternatives, including, where practicable, a standard permitting no discharge of pollutants. Section 304(b) of the Act requires the Administrator to publish within one year of enactment of the Act, regulations providing guidelines for effluent limitations setting forth the degree of effluent reduction attainable through the application of the best practicable control technology currently available and the degree of effluent reduction attainable through the application of the best control measures and practices achievable including treatment techniques, process and procedure innovations, operation methods and other alternatives. The regulations proposed herein set forth effluent limitations, guidelines pursuant to Section 304(b) of the Act for the steam electric powerplant industry.

Section 306 of the Act requires the Administrator, within one year after a category of sources is included in a list published pursuant to Section 306(b) (1) (A) of the Act, to propose regulations establishing Federal standards of performances for new sources within such categories. The Administrator published in the Federal Register of January 16, 1973 (38 F.R. 1624), a list of 27 source categories. Publication of the list constituted announcement of the Administrator's intention of establishing, under Section 306, standards of performance applicable to new sources within the steam electric powerplants industry category, which was included within the list published January 16, 1973. See Table III-1 for a summary of the principal statutory considerations.

Section 304(c) of the Act requires the Administrator to issue informaton on the processes, procedures or operating methods which result in the elimination or reduction in the discharge of pollutants to implement standards of performance under section 306 of the Act. Such information is to include technical and other data, including costs, as are available on alternative methods of elimination or reduction of the discharge of pollutants.

Section 316(a) of the Act provides that whenever the owner or operator of any point source can demonstrate to the satisfaction of the Administrator that any effluent limitation proposed for the control of the thermal component of any discharge will require more stringent control measures than are necessary to assure the protection and propagation of a balanced, indigenous population of shellfish, fish and wildlife in and on the body of water into which the discharge is to be made the Administrator may impose less stringent limitations with respect to the thermal component, (taking into account the interaction of such thermal component with other pollutants) that will assure the

Table III-1

PRINCIPAL STATUTORY CONSIDERATIONS

STATUTORY BASIS	General Description	Process Changes	Cost	Process Employed, Age & Size of Equipment & Facilities	Non Water Quality Environmental Impact & Energy
Best Practicable Control Technology Currently Available 304(b)(1)(A) [Existing Sources]	1. Achieve by 1977. 2. Generally average of best existing performance; high confidence in engineering viability. 3. Where treatment uniformly inadequate a higher degree of treatment may be required if practicable [compare existing treatment of similar wastes].	Normally does not emphasize in-process controls, except where presently commonly practiced.	Balancing of total cost of treatment against effluent reduction benefits.	Age, size & process employed may require variations in discharge limits (taking into account compatibility of costs and process technology)	Assess impact of alternative controls on air, solid waste, noise, radiation and energy requirements.
Best Available Technology Economically Achievable 304(b)(1)(B) [Existing Sources]	1. Achieve by 1983. 2. Generally best existing performance but may include technology which is capable of being designed, though not yet in place; further development work could be required.	Emphasizes both in-process and end-of-process control.	Costs considered relative to broad test of reasonableness.	Age, size & process employed may require variations in discharge limits (taking into account compatibility of costs and process technology)	Assess impact of alternative controls on air, solid waste noise, radiation and energy requirements.
Standards of Performance Best Available Demonstrated Control Technology 306 [New Sources]	1. Achieved by sources for which "construction" commences after proposal of regulations. 2. Generally same considerations as for 1983; more critical analysis of present availability.	Emphasizes process changes.	Cost considered relative to broad test of reasonableness.	N/A	Assess impact of alternative controls on air, solid waste, noise, radiation and energy requirements.

protection and propagation of a balanced, indigenous population of shellfish, fish, and wildlife in and on that body of water.

The Act defines a new source to mean any source, the construction of which is commenced after the publication of proposed regulations prescribing a standard of performance. Construction means any placement, assembly, or installation of facilities or equipment (including contractual obligations to purchase such facilities or equipment) at the premises where such equipment will be used, including preparation work at such premises.

Scope of Work and Technical Approach

This document was developed, specifically, for effluent discharge from steam electric powerplants covered under Standard Industrial Classification (SIC) 1972 Industry Nos. 4911 and 4931, relating to liquid discharges to navigable waters of the United States.

Industry No. 4911 encompasses establishments engaged in the generation, transmission and/or distribution of electric energy for sale. Industry No. 4931 encompasses establishments primarily engaged in providing electric service in combination with other services, with electric services as the major part though less than 95 percent of the total. The S.I.C. Manual (1972) recommends that, when available, the value of receipts or revenues be used in assigning industry codes for transportation, communication, electric, gas, and sanitary services.

The study was limited to powerplants comprising the electric utility industry, and did not include steam electric powerplants in industrial, commercial or other facilities. Electric generating facilities other than steam electric, such as combustion gas turbines, diesel engines, etc. are included to the extent that power generated by the establishment in question is primarily through steam electric processes.

This report covers effluents from both fossil-fueled and nuclear plants and excludes the radiological aspects of effluents.

The Act requires that in developing effluent limitations, guidelines and standards of performance for a given industry, certain factors must be considered, such as the total cost of the application of technology in relation to the effluent reduction benefits to be achieved, age of equipment and facilities, processes employed, engineering aspects of the application of various types of control techniques, process changes, non-water quality environmental impact (including energy requirements) and other factors. For steam electric powerplants, formal segmentation of the industry based on all the factors mentioned in the Act has been found to be inapplicable. However, the two basic aspects of the effluents produced by the industry, chemical aspects and thermal aspects, were found to involve such divergent considerations that a basic distinction between guidelines for chemical wastes and thermal discharges was determined to be most useful in achieving the objectives of the Act. Accordingly, this report covers waste categorization, control and treatment technology and recommendations for effluent limitations for chemical and other nonthermal aspects of waste discharge in Part A and similar subjects for thermal aspects of discharges in Part B of this report considering the factors cited in the Act.

Section 502(6) of the Act defines the term pollutant in relation to the discharge into water of certain materials, substances and other constituents of discharge. The inclusion of heat in the list of pollutants indicates the clear intention on the part of Congress to have this pollutant included in the same manner as other pollutants in the establishment of effluent limitation guidelines and standards of performance. Other recognition of heat in special provisions of the Act is in Sections 104(t) and 316.

Section 104(t) requires the EPA Administrator in cooperation with other agencies and organizations to conduct continuing comprehensive studies of the effects and methods of control of thermal discharges. The studies are to include cost-effectiveness analysis and total impact on the environment. The Act states that they are to be used by EPA in carrying out Section 316 of the Act, and by the States in establishing water quality standards. However it does not indicate that the studies are to be utilized in establishing effluent limitation guidelines and standards of performance. Section 316(a) does provide for individual variances to be granted from effluent guidelines for thermal discharges, where such a variance will assure the protection and propogation of a balanced, indigenous population of shellfish, fish and wildlife in and on that body of water.

Consequently, the Act requires effluent guidelines and standards of performance for heat to be developed in the same manner as for other pollutants, but also allows for individual relief from the guidelines and standards under Section 316. In this context, this report only contains an evaluation of control and treatment technology for thermal discharges which reduces or eliminates the amounts of heat discharged. Consideration of mixing zone technology is therefore not included, since mixing zones do not reduce the effluent heat but rely in part upon the dilution effect of the receiving water to decrease the overall receiving water temperatures to meet applicable limitations based on environmental criteria. Therefore they do not qualify as a control or treatment technology for the establishment of technology-based effluent limitations guidelines or standards of performance.

The effluent limitations and standards of performance recommended herein have been developed from a detailed review of current practices in the steam electric powerplant industry. A critical examination was made of treatment methods now in use in the industry and methods used in other industries to achieve solutions to problems similar to those encountered in steam electric powerplants. As part of the review of current practices, applications for discharge permits filed in accordance with other provisions of the Act were examined. There is also a volumuous literature base and on-going reseach development and demonstration programs in this and related technical areas. Also as part of this effort visits were made to 35 plants, with at least one plant visit to each of the ten EPA regions. Six plants were visited outside the U.S. Sampling programs were conducted at plants where it was felt that sufficient information could be obtained to document treatment practices. The plants visited are listed below:

Beznau, Dottingen,Switzerland
B.F. Cleary, Taunton, Massachusetts
Big Brown, Fairfield, Texas
Brayton Point, Somerset, Massachusetts
Canal, Sandwich, Massachusetts
Centralia, Centralia, Washington
Cherokee, Denver, Colorado
Chesterfield, Chester, Virginia
Dresden, Morris, Illinois
Dunkirk, Dunkirk, New York
Fremont No. 1, Fremont, Nebraska
Fremont No. 2, Fremont, Nebraska
Fort Calhoun, Fort Calhoun, Nebraska
Greene County, Demopolis, Alabama
Holtwood, Holtwood, Pennsylvania
Keystone, Shelocta, Pennsylvania
Lichterfelde, West Berlin
Marshall, Terrell, North Carolina

Milliken, Ludlowville, New York
Mohave, Davis Dam, Nevada
Morgantown, Newburg, Maryland
North Omaha, Omaha, Nebraska
Palisades, Benton Harbor, Michigan
Paradise, Drakesboro, Kentucky
Pittsburg, Pittsburg, California
Preussag, Ibbenburen, West Germany
Quad Cities, Cordova, Illinois
Rancho Seco, Rancho Seco, California
Roseten, Roseton, New York
Rugeley, Town of Rugeley, England
Sanford, Sanford, Florida
Turkey Point, Florida City, Florida
Valmont, Valmont, Colorado
Volkswagenwerk, Wolfsburg, West Germany
Westfalen, Schmehausen, West Germany
Will County, Joliet, Illinois

The economic analyses contained in this report pertain only to costs related to control and treatment technology for the reduction and elimination of the discharge of pollutants from steam electric powerplants. Benefits derived from associated costs are simply the reduction and/or elimination of pollutant discharges. Cost-benefit analysis which consider environmental effects, benefits to society, economic impact, etc. are beyond the scope of this report.

In arriving at recommendations fcr effluent limitations guidelines and standards of performance, extensive use has been made of prior studies in this area made for EPA, in-house information developed by EPA, information developed by industry sources, and comments submitted by numerous Federal and State agencies, industrial and other groups, and others.

Industry Description

Steam electric powerplants are the production facilities of the electric power industry. The industry also provides for the transmission and distribution of electric energy. The industry is made up of two basically distinct ownership categories, investor-owned and publicly-owned, with the latter further divided into Federal agencies, non-Federal agencies, and cooperatives. About two-thirds of the 3400 systems in the United States perform only the distribution function, but many perform all three functions, production (generally referred to as generation), transmission, and distribution. In general, the larger systems are vertically integrated, while the smaller systems, largely in the municipal and cooperative categories, rely on firm purchases to meet all or part of their requirements. Many of the systems are interconnected, and can, under emergency conditions, obtain power from other systems.

Historically, the industry started around 1880 with the construction of Edison's steam electric plant in New York City. For the next sixty years, growth was continuous, but unspectacular, due to the fairly limited demand for power. However, since 1940 the annual per capita production of electric energy has grown at a rate of about six percent per year, and the total energy consumption by about seven percent. In 1970, there were about one thousand generating systems in the United States. These systems had a combined generating capacity of 340,000 megawatts (Mw) and produced 1,530,000,000 megawatt hours (Mwh) of energy. A breakdown of the capacity and production by ownership categories is given in Table III-2.

The industry produces, transmits and distributes a single product, electric energy. The product is distinguished from other products of the American industry by the fact that it cannot be economically stored, and that the industry must be ready to produce at any give time all the product the consumer desires to utilize. While some industrial power is sold on a so-called "interruptible" basis, the total amount sold on this basis is insignificant compared to the overall power consumption. The ability of the industry to meet any instantaneous demand is the criterium for what constitutes satisfactory performance in the industry and is the single most significant factor in determining the need for new generating facilities.

Other special considerations involved in a discussion of the industry relate to its role as a public utility, a monopoly, and a regulated industry. As a public utility, its major objective is to provide a public service. It must supply its product to all customers within its assigned service area, but it cannot discriminate between customers, and it must supply its product to all customers within a given class at equal cost. As a monopoly, the industry is generally assigned a service area, but within that area is exempt from competition except perhaps for competition with other sources of energy, particularly in the industrial area. However, in return for the granting of a monopoly, the industry is required to furnish service. Thus it cannot cease to service a certain area when such service appears to be unprofitable. Finally, in view of its position as a public utility and a monopoly, both the quality of service it must provide and the rates it may charge for its service

Table III- 2

SUMMARY DESCRIPTION

ELECTRICAL POWER GENERATING INDUSTRY (YEAR 1970)

Number of plants (stations)................approx. 1000

Number of generating units.................approx. 3000

OWNERSHIP	NUMBER OF SYSTEMS*	GENERATING CAPACITY, Mw*	GENERATION, 10^6 Mwh*
Investor	250	265,000	1,180
Federal	2	40,000	190
Public (non-Fed)	700	35,000	140
Cooperative	65	5,000	22

CUSTOMERS	NUMBER	ENERGY SOLD, Mwh
Residential	55,000,000	450,000,000
Commercial	8,000,000	325,000,000
Industrial	400,000	575,000,000
Other	-	60,000,000

PROJECTED GROWTH	INSTALLED CAPACITY, Mw
1970	266,000
1980	540,000
1990	1,057,000

FUEL USED	PERCENT HEAT INPUT
Coal	54
Natural Gas	29
Oil	15
Nuclear	2

COST (YEAR 1968)	mills/kwh
Production	7.7
To Customers	15.4

* Note: Includes some hydroelectric and internal combustion.

are regulated by both State and Federal regulatory agencies. Since the rates it is allowed to charge are a function of the cost of providing service, any prudent costs imposed on the industry by regulatory agencies will eventually be passed on to the electricity consumer. And since the consumer, particularly at the retail residential level, has very few options to the use of electricity, the relationship between costs and consumption is generally considered to be "inelastic" in the short time, that is, an increase in cost has little effect on the level of consumption.

The use of electric energy can be divided into three major categories: industrial, residential and commercial. In 1965, industrial use accounted for 41% of all energy generated. Residential use accounted for 24% and commercial use for 18%. Another 17% of the energy generated was used by miscellaneous users for auxiliary operations within the industry or lost in transmissions. Studies by the Federal Power Commission (FPC) indicate no change in this basic use pattern over the next two decades.

On the other hand, the total amount of electric energy that will be used is expected to increase significantly over the next two decades. Again, based on studies by the FPC, it is believed that the required generating capacity will increase from 340,000 Mw in 1970 to 665,000 Mw in 1980 and 1,260,000 Mw in 1990. The industry's 1970 generating facilities would therefore have to be almost doubled by 1980 and again doubled by 1990.

At the present time, steam electric powerplants, including both fossil-fueled and nuclear-fueled plants, account for about 79% of total generating capacity and 83% of the total power generated. The remainder is accounted for by hydroelectric generation, both of the once-through and pumped-storage types, and by direct combustion-generation processes such as gas turbines and diesel engine driven generators. Table III-3, taken from reports of the FPC, shows the projected growth of generating capacity over the next two decades.

Four basic fuels are used in steam electric powerplants, three fossil fuels-coal, natural gas and oil - and uranium, presently the basic fuel of nuclear power. A potential fuel, reclaimed refuse, is being burned at one experimental facility, but is not likely to have a major impact on the industry within the foreseeable future. Table III-4, again from FPC reports, shows the projected distribution of fuel use for steam electric power generation for the next two decades.

TABLE III- 3

PROJECTED GROWTH OF UTILITY ELECTRIC GENERATING CAPACITY
(Figures in thousands of megawatts)

Type of Plant	1970 (actual)		1980		1990	
	Capacity	% of Total	Capacity	% of Total	Capacity	% of Total
Fossil Steam	260	76	393	59	557	44
Nuclear Steam	6	2	147	22	500	40
Subtotal Steam	266	78	540	81	1,057	84
Hydroelectric-conventional	52	15	68	10	82	6
Hydroelectric-pumped storage	4	1	27	4	71	6
Gas-Turbine and Diesel	19	6	31	5	51	4
TOTALS	341	100	666	100	1,261	100

Notes: (1) These projections are keyed to the electrical energy demand projections made by Regional Advisory Committee studies carried out in the 1966-1969 period.

(2) The projections are premised on an average gross reserve margin of 20%.

(3) Since different types of plants are operated at different capacity factors, this capacity breakdown is not directly representative of share of kilowatt-hours production. For example, since nuclear plants are customarily used in base-load service and therefore operate at comparatively high capacity factors, nuclear power's contribution to total electricity production would be higher than its capacity share.

Table III-4

FPC PROJECTION OF FUEL USE IN STEAM ELECTRIC POWERPLANTS

Fuel	1970	1980	1990
Coal	54%	41%	30%
Natural Gas	29	14	8
Fuel Oil	15	14	9
Nuclear	2	31	53

Table III-5 shows the projected annual fuel requirements for steam electric powerplants over the next two decades. See also Figure III-1 for a graphical presentation of the projection, by the Joint Committee on Atomic Energy, of the U.S. energy flow pattern for 1980. Although their share of the total fuel use is declining, the actual use of all three fossil fuels is projected to continue to increase. Most significant is the fact that utility consumption of coal will more than double although coal's share of the total use will decrease from 54% to 31%. These projections assume no major slippages in the construction of nuclear generating plants. Should such slippages occur, it is possible that coal will be called upon to assume an even greater role in meeting the nation's energy needs.

Coal is the most abundant of the fossil fuels. Nationwide it is estimated that proven recoverable reserves are sufficient to supply our needs for the next 200 to 300 years. A problem with coal is that it varies in chemical properties and its geographic distribution does not coincide with the geographic distribution of the demand for electric energy. A primary concern is the sulfur content of the coal. Most of the Eastern coal is too high in sulfur content to meet the increasingly stringent limits on sulfur dioxide in stack gases.

Sulfur dioxide removal systems are being employed at a number of powerplants. All indications are that limitations on sulfur dioxide emissions will substantially increase production costs in coal-burning powerplants. In the West, there are large deposits of low sulfur coal, but here the cost of either shipping the coal or transmitting electric energy are substantial. The possibilities of further environmental restrictions as much as the actual environmental regulations now in force has possibly resulted in the conversion of a large number of coal burning plants to other forms of fossil fuel, and the construction of new generating facilities using less abundant but more environmentally acceptable fuels.

Both natural gas and low sulfur residual oils are in short supply. The natural gas situation was initially felt to be more critical and some generating plants were being converted from natural gas to fuel oil. The 1970 FPC projections indicated that natural gas utilization would remain fairly constant and that the use of fuel oil would increase at approximately the same rate as the use of coal. All of these projections were based on the assumption that there would be no additional governmental actions regulating the utilization of fuels and that nothing would happen to

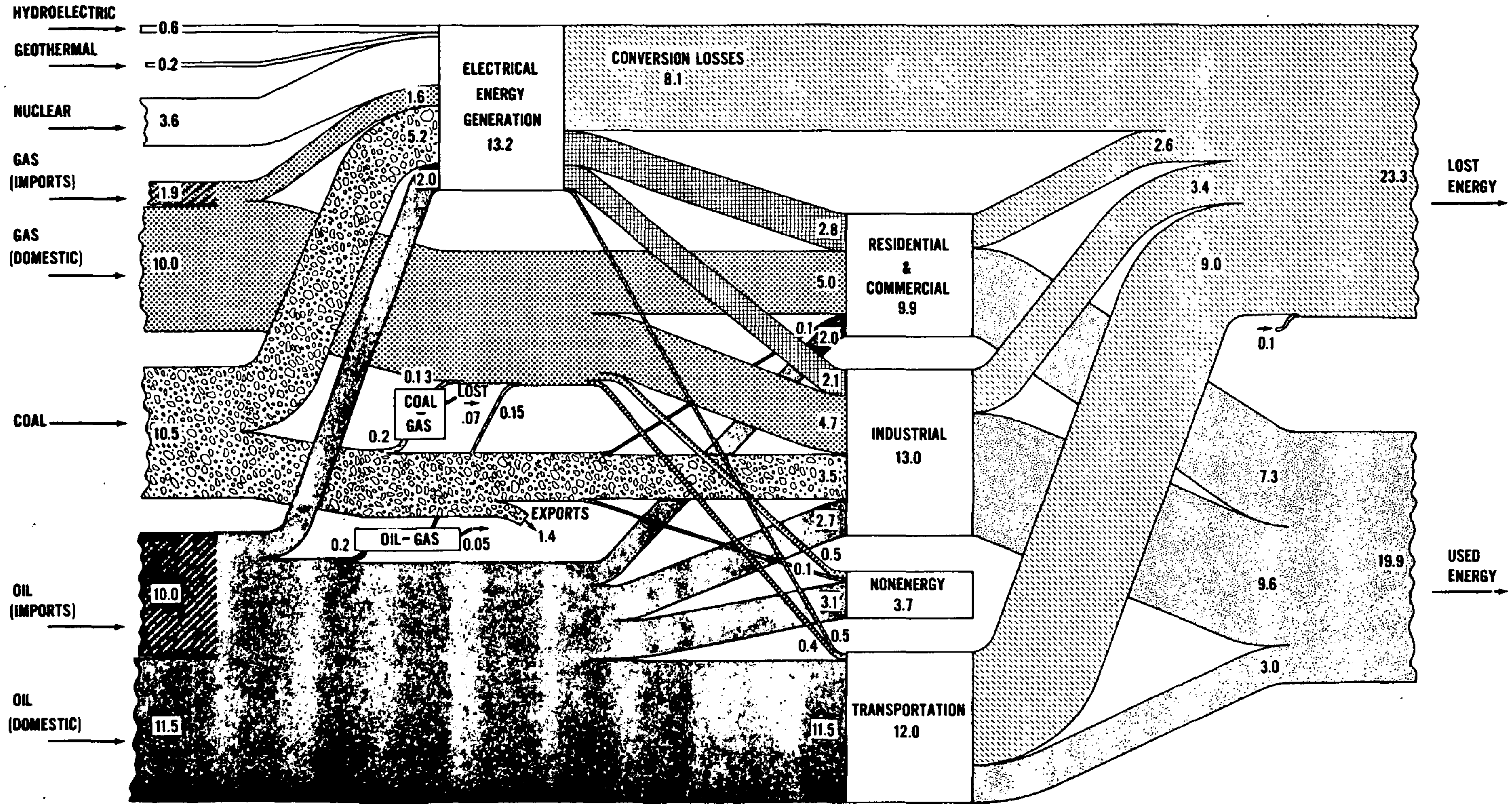
Table III- 5

FPC PROJECTED ANNUAL FUEL REQUIREMENTS FOR STEAM ELECTRIC POWERPLANTS

Fuel	Measure	1970	1980	1990
Coal	10^6 tons	332	500	500
Natural Gas	10^{12} cubic feet	3.6	3.8	3.8
Fuel Oil	10^6 barrels	331	640	800
U_3O_8	10^3 tons to diffusion plants without recycle of plutonium	7.5	41	127

Figure III-1

PROJECTED TOTAL U.S. ENERGY FLOW PATTERN (1980)[234]



(UNITS: MILLION BBLS/DAY OIL EQUIVALENT) affect our present heavy reliance on foreign sources for fuel oil. Subsequently, the fuel oil problem became critical, projections were altered and certain plants were considered for reconversion to coal.

Finally, the projected growth of nuclear generating capacity is dependent in the short run on the discovery of additional deposits of low-cost uranium and the construction of additional ore processing facilities. In the long run, it is dependent on the successful development and use of breeder reactor systems. The United States may have a full-scale breeder plant in operation in the 1980's.

In summary, this report deals with the setting of effluent guidelines for an industry with many complex aspects. It is a public utility and therefore is regulated both as to the quality of its service and the rates it can charge for the service. While regulation limits the rates it can charge, it also insures that any prudently increased costs will eventually be passed on to the retail customer. Except for some competition in the industrial use of electricity, there is little competition for the use of its product. On the other hand, the industry itself has little mobility. A powerplant generally cannot be moved and a generating unit can be shut down only when an equivalent unit has been provided. Since its product cannot be stored and must be produced to meet a fluctuating demand, much of its capacity is used only part time. With suitable sites near the centers of demand largely used up, it has to go further and further from its demand to obtain satisfactory generating sites, and even then is often encountering pressure from environmental groups opposed to the construction of the new facilities. In addition, because of planning, construction and design problems with regard to a number of plants already sited, delays are resulting for some major power plant installations. Generally, the slippage in the schedules for new powerplants is requiring the industry to continue to operate some of the older, less efficient, and perhaps less environmentally acceptable plants. Amplification of the "energy crisis" has evoked considerable attention, constraints, and changes in the industry. In addition to some shifts in fuel and fuel costs, reduced projections for the demand for electricity and possibly other factors have caused at least one major system to announce a slowdown in planned expansion resulting in the delay in construction of generating units.

The setting of effluent standards for steam electric powerplants has therefore involved a large number of complex factors, many of which do not apply to a conventional manufacturing industry producing a non-perishable, transportable product in a competitive market.

Process Description

The "production" of electrical energy always involves the utilization and conversion of some other form of energy.

The three most important sources of energy which are converted to electric energy are the gravitational potential energy of water, the atomic energy of nuclear fuels, and the chemical energy of fossil fuels. The utilization of water power involves the transformation of one form of mechanical energy into another prior to conversion to electrical energy, and can be accomplished at greater than 90 percent of theoretical efficiency. Therefore, hydroelectric power generation involves only a minimal amount of waste heat production due to conversion inefficiencies. Present day methods of utilizing the energy of fossil fuels, on the other hand, are based on a combustion process, followed by steam generation to convert the heat first into mechanical energy and then to convert the mechanical energy into electrical energy. Nuclear processes as generally utilized also depend on the conversion of thermal energy (heat) to mechanical energy via a steam cycle. Although progress in powerplant development has been rapid, a large part of the energy released by the fuel as heat at a high temperature level, in even the most efficient plants, is not converted to useful electrical energy, but is exhausted as heat at a lower temperature level. This is due to the limitations of the second law of thermodynamics which can be stated as follows: A reversible heat engine can generate work from high-temperature heat only at the expense of rejecting a part of this heat to a lower-temperature reservoir. The fraction of the high-temperature heat which is converted to work is (T-t)/T, where T is the absolute temperature of the high-temperature heat source and t is the absolute temperature of the lower-temperature heat sink.

Where a water-steam cycle is used to convert heat to work, the maximum theoretical efficiency that can be obtained is limited by the temperatures at which the heat can be absorbed by the steam and discarded to the environment. The upper temperature is limited by the temperature of the fuel bed and the structural strength and other aspects of the boiler. The lower temperature is ideally the ambient temperature of the environment, although for practical purposes the reject temperature must be set by design significantly above the highest anticipated ambient temperature. Within these temperatures it can be shown that the conversion of heat into any other form of energy is limited to efficiencies of about 40 percent regardless of any improvements to the present day machines employed. The limited boiler temperature utilized by present day light water nuclear powerplants is the major reason of the lower efficiency of these plants compared to fossil-fueled plants. For any steam electric power generation scheme, therefore, a minimum of about 60 percent of the energy contained in the fuel must be rejected to the environment as waste heat. The extent to which existing and future steam electric powerplants approach this theoretical limit will be discussed later in this report, as will alternate methods of converting fuel energy to electric energy which do not employ a steam cycle and therefore are not limited to steam cycle efficiencies.

Fossil-fueled steam electric powerplants produce electric energy in a four stage process. The first operation consists of the burning of the fuel in a boiler and the conversion of water into steam by the heat of combustion. The second operation consists of the conversion of the high-temperature high-pressure steam into mechanical energy in a steam turbine. The steam leaving the turbine is condensed to water, transferring heat to the cooling medium, which is normally water. The turbine output is conveyed mechanically to a generator, which converts the mechanical energy into electrical energy. The condensed steam is reintroduced into the boiler to complete the cycle.

Nuclear powerplants utilize a similar cycle except that the source of heat is atomic interactions due to nuclear fuel rather than combustion of fossil fuel. Water serves as both moderator and coolant as it passes through the nuclear reactor core. In a pressurized water reactor, the heated water then passes through a separate heat exchanger, where steam is produced on the secondary side. This steam, which contains no radioactive materials, drives the turbine. In a boiling water reactor, steam is generated directly in the reactor core and is then piped directly to the turbine. This arrangement results in some radioactivity in the steam and therefore requires some shielding of the turbine. Long term fuel performance and thermal efficiencies are similar for the two types of nuclear systems.

The theoretical water-steam cycle employed in steam electric powerplants is known as the Rankine cycle. Actual cycles in powerplants only approach the performance of the Rankine cycle because of practical considerations. Thus, the heat absorption does not occur at constant temperature, but consists of heating of the liquid to the boiling point, converting of liquid to vapor and superheating (heating above the saturation equilibrium temperature) the steam. Superheating is necessary to prevent excess condensation in the turbines and results in an increase in cycle efficiency. Reheating, the raising of the temperature above saturation of the partially expanded steam, is used to obtain improvements in efficiency and again to prevent excess condensation. Preheating, bringing of condensate to near boiling temperatures with waste heat, is also used for this purpose. Condensers cannot be designed to operate at theoretically optimum values because it would require infinitely large equipment. All of these divergences from the optimum theoretical conditions cause a decrease in efficiency and an increase in the amount of heat rejected per unit of production. As a result, only a few of the larger and newer plants approach even the efficiencies possible under the ideal Rankine cycle. Also as a result of second law limitations, modifications of the steam cycle of an existing plant are not likely to result in significant reductions in heat rejection.

Alternate Processes

Alternate processes for generating electric energy can be divided into three distinct groups. The first group includes those processes that are presently being used to generate significant amounts of electrical energy. This group includes hydroelectric power generation, combustion gas turbines, and diesel engines. The second group includes processes that seek to improve on the steam electric cycle by utilizing new fuels or new energy technology. This group includes liquid metal fast breeder reactors, geothermal generation, utilization of solar energy, and various forms of combining cycles to obtain greater thermal efficiency. The last group includes those systems, also mostly still under development, that seek to eliminate the inherent limitations of the conventional Rankine cycle by providing for some alternative type of conversion of chemical energy into electrical energy. This group includes magnetohydrodynamics, electrogasdynamics and fuel cells.

Presently Available Alternate Processes

Hydroelectric Power

Hydroelectric developments harness the energy of falling water to produce electric power, and have a number of distinct advantages over steam electric plants. Operation and maintenance costs are generally lower. Although the initial capital cost may be higher, hydroelectric developments have longer life and lower rates of depreciation, and capital charges may therefore be less. The cost of fuel is not an item of operating cost. Both availability and reliability are greater than for steam electric units. Hydroelectric plants are well suited for rapid start and rapid changes in power output and are therefore particularly well adapted to serve peak loads. Best of all, hydroelectric plants do not consume natural fuel resources, produce no emissions that affect air quality and discharge no significant amounts of heat to receiving waters.

Unfortunately, the availability of hydroelectric power is limited to locations where nature has created the opportunity by providing both the stream and the difference in elevation to make the energy extractable. In many instances this means generation far away from load centers with long transmission lines required to bring the energy to its point of use. At the present time, hydroelectric generation in the United States is a major factor only in the Far West, in New York State, and in some areas of the Appalachian Region. Total hydroelectric capacity installed at the end of 1970 amounted to 52,300 Mw, amounting to about 15% of the total installed U. S. generating capacity. In spite of a projected growth of about 30,000 Mw by 1990, the share of once-through hydroelectric power is expected to decline to about 7% by 1990. The primary reason for this decline is that the best available sites for hydroelectric power have already been developed and that the remaining sites are either too far from load centers or too costly to develop. Development of some sites may be prohibited by legislation such as the Colorado River Basin Project Act (P. L. 90-537) and the Wild and Scenic Rivers Act (P. L. 90-542). Development of the maximum potential at other sites may be limited by the Federal Power Act which requires that a project to be licensed or relicensed be best adapted to a comprehensive plan for the use of the basin's resources.

There is a possibility of importing substantial blocks of hydroelectric power from eastern Canada, but the rapid rate of growth in Canada has possibly been a factor in the inability of that country and the United States to enter into long-term contracts for the sale of power. As much as 5,000 Mw might be available on a short-term basis of about twenty years and could be transmitted to load centers in the Northeastern United States at economically feasible costs.

One form of hydroelectric power, pumped storage projects, is expected to play an increasing role in electric power generation. In a pumped storage project water is pumped, by electricity generated by thermal units, into an elevated reservoir site during off-peak hours and electricity is then generated by conventional hydro means during the periods of peak usage. Pumped storage plants retain the same favorable operating characteristics as once-through hydroelectric plants. Their ability to accept or reject large blocks of energy very quickly make them much more flexible than either fossil-fueled or nuclear plants. Of course, the power required to pump the water into the reservoir must be generated by some other generating facility. Efficiencies of pumping and of hydroelectric generation are such that about 3 kwh of energy must be generated for each 2 kwh recovered, but on many systems the loss of 1 kwh of non-peak fuel consumption in lieu of 2 kwh (equivalent) of capital expenditure for additional peak generating capacity is favorable in the light of overall system economics.

Although the earliest pumped storage project dates back to 1929, total pumped storage capacity at the end of 1970 amounted to only 3,700 Mw. FPC estimates indicate that pumped storage capacity may reach 70,000 Mw by 1990. This would represent a higher rate of growth than the projected growth of the entire industry.

Although hydroelectric plants produce neither air emissions nor thermal discharges, some proposed projects have drawn opposition from environmental groups because of the large volumes of water being drawn through the turbine-pump units, with the associated potential for damage to marine life, and the relatively large areas of uncertainty surrounding the effect of artificial reservoirs on groundwater regimen. Several of the pumped storage project reservoirs have required remedial measures to reduce leakage of water from the reservoir.

In general, hydroelectric power represents a viable alternative to fossil-fueled or nuclear steam cycle generation where geographic, environmental and economic conditions are favorable. Pumped storage additionally offers an opportunity to improve overall system performance and reliability, particularly for rapid startup and maintenance of reserves ready to be loaded on very short notice.

Combustion Gas Turbines and Diesel Engines

Combustion gas turbines and diesel engines are devices for converting the chemical energy of fuels into mechanical energy by using the Brayton and Diesel thermal cycles as opposed to the Rankine cycle used with steam. As with the Rankine cycle, the second law of thermodynamics imposes upper limits as their ideal energy conversion efficiencies based on the maximum combustion temperature and the heat sink temperature (ambient air). The actual conversion efficiencies of combustion gas turbines and diesel engines are lower than those of the better steam cycle plants. Diesel engines are used in small and isolated systems as a principal generator of electrical energy and in larger systems for emergency or standby service. Combustion gas turbines are used increasingly as peaking units and in some instances as part of combined cycle plants, where the hot exhaust gases from a combustion gas turbine are passed through a boiler to generate steam for a steam turbine. Both types of units are relatively low in capital cost ($/kw), require little operating labor, are capable of remote controlled operation, and are able to start quickly. Since these units typically operate less than 1,000 hours per year, fuel costs are generally not a deciding factor.

In a combustion gas turbine, fuel is injected into compressed air in a combustion chamber. The fuel ignites, generating heat and combustion gases, and the gas mixture expands to drive a turbine, which is usually located on the same axle as the compressor. Various heat recovery and staged compression and combustion schemes are in use in order to increase overall efficiency. Aircraft jet engines have been used to drive turbines which in turn are connected to electric generators. In such units, the entire jet engine may be removed for maintenance and a spare installed with a minimum of outage time. Combustion gas turbines require little or no cooling water and therefore produce no significant thermal effluent.

Diesel engines can be operated at partial or full loads, are capable of being started in a very short time, and are ideally suited for peaking use. Many large steam electric plants contain diesel generators for emergency shutdown and startup power if the plant is isolated from outside sources of power.

In 1970, combustion gas turbine and diesel engines represented 6% of the total United States generating capacity. This represented 15,000 Mw of combustion gas turbines and 4,000 Mw of diesel engines.

Alternate Processes Under Active Development

Future Nuclear Types

At the present time almost all of the nuclear powerplants in operation in the United States are of the boiling water reactor (BWR) or pressurized water reactor (PWR) type. As previously discussed some technical aspects of these types of reactors limit their thermal efficiency to about 30%. There are potential problems in the area of fuel availability if the entire future nuclear capacity is to be met with these types of reactors. In order to overcome these problems, a number of other types of nuclear reactors are in various stages of development. The objective of developing these reactors is two-fold, to improve overall efficiency by being able to produce steam under temperature and pressure conditions similar to those being achieved in fossil fuel plants, and to assure an adequate supply of nuclear fuel at a minimum cost. Included in this group are the high temperature gas-cooled reactor (HTGR), the seed blanket light water breeder reactor (LWBR), the liquid metal fast breeder reactor (LMFBR), and the gas-cooled fast breeder reactor (GCFBR). All of these utilize a steam cycle as the last stage before generation of electric energy. Both the HTGR and the LMFBR have advanced sufficiently to be considered as potentially viable alternate processes.

The HTGR is a graphite-moderated reactor which uses helium as a primary coolant. The helium is heated to about 750 degrees centigrade (1400 degrees Fahrenheit), and then gives up its heat to a steam cycle which operates at a maximum temperature of about 550 degrees centigrade (1,000 degrees Fahrenheit). As a result, the HTGR can be expected to produce electric energy at an overall thermal efficiency of about 40%. One HTGR is operating in the United States at this time, with another expected to be operating in 1974. The thermal effects of its discharges should be similar to those of an equivalent capacity of fossil-fueled plants. Its chemical wastes will be provided with essentially similar treatment systems that are presently being provided for BWR and PWR plants.

The LMFBR will have a primary and secondary loop cooled with sodium, and a tertiary power producing loop utilizing a conventional steam system. Present estimates are that the LMFBR will operate at an overall thermal efficiency of about 36%, although higher efficiencies are deemed to be ultimately possible. The circulating water thermal discharges of the LMFBR will initially be about halfway between those of the best fossil-fueled plants and the current generation of nuclear plants. Chemical wastes will be similar to those of current nuclear plants.

Coal Gasification

The technology for producing from coal a low Btu gas suitable for combustion in a utility powerplant has long been available. Thus far, the economics of processing the coal at the mine and transporting gas to the point of use have not been sufficiently favorable to lead to the construction of large scale facilities based on this process.

The attractiveness of the concept lies in its potential for utilizing the most abundant of the fossil fuels, coal, without the problems usually associated with coal, sulfur and particulates in the stack gases and ash and slag problems in the boiler. The drawbacks are that coal gasification only returns 2 kw for each 3 kw of coal processed, large capital investments are required, and the resulting cost per Btu is high.

The Federal Government and a number of private organizations are supporting research and development seeking to reduce the cost of coal gasification. There are at least eight process alternates in various stages of development with different by-products or energy requirements. Best current estimates are that low Btu gas could be produced from coal for about twice the average price currently (1973) paid by electric utilities for natural gas. With an increasing shortage of natural gas and fuel oil and increasing pressure on the utilities for environmentally "clean" generation of electric energy, coal gasification could well turn into a significant factor in the steam electric powerplant industry.

Combined Cycles

One possible avenue toward greater overall thermal efficiency lies in first utilizing the hot gases generated by combustion of the fuel in a combustion gas turbine and then passing the exhaust of the turbine through a steam boiler. A small number of plants based on this concept have been constructed. One problem lies in the fact that present-day turbine technology requires a relatively clean gas or light oil (natural gas or refined oil) fuel. Gas turbines are used primarily as peaking units due to the shortage of natural gas supplies, its high cost per unit of heating value, and the relatively high maintenance cost of the equipment. Thermal efficiency is a primary consideration only for base loaded units and experience with gas turbines used as base- load units is limited.

A major advantage of the combustion gas turbine is the fact that it requires no cooling water. Conversion of existing units or plants to combined cycle offers, at least in theory, the potential for reducing the thermal effects associated with a given production of electrical energy. In practice, the modification of existing equipment is generally likely to be technically difficult, if not impossible, and of doubtful economic viability.

One form of combining cycles that holds special attraction is the utilization of municipal refuse as a source of energy for the production of steam and electrical power. Municipal refuse has an average heating value of about 12,000 J/g (5000 Btu/lb). Many municipalities have been forced to incineration of their refuse by the growing scarcity of available and environmentally acceptable sites for landfill operations. In European countries, higher fuel costs and lower wages have resulted in economics favorable to the recovery of heat from the incineration of refuse. In the United States, general practice has been to incinerate refuse in refractory furnaces without attempt at heat recovery, although several large municipal incinerators now generate steam.

Plant No. 2913 has been converted to accept a mixture of 10 to 20% shredded refuse and 80 to 90% powdered coal. The refuse has previously been processed to remove a portion of the ferrous metals. The operation appears to be reasonably successful. However, the modifications to both the refuse disposal operations and the production of electric energy are such that the economics must be carefully evaluated in each individual case.

Future Generating Systems

Magnetohydrodynamics

Magnetohydrodynamic (MHD) power generation consists of passing a hot ionized gas or liquid metal through a magnetic field to generate direct current. The concept has been known for many years, although specific research directed towards the development of viable systems for generating significant quantities of electric energy has only been in progress for the past ten years.

The promise of MHD lies in its potential for high overall system efficiencies, particularly if applied as a "topping" unit in conjunction with a conventional steam turbine. The exhaust from a MHD generator is still at a sufficiently high temperature to be utilized in a waste heat boiler. The combined MHD-steam cycle could result in overall system efficiencies of 50 to 60% and would require substantially less cooling water than presently available systems.

The problems with MHD lie in the development of suitable materials that can withstand temperatures in the 2200-2800°C (4000-5000°F) range. This includes electrodes, channels, and auxiliary components. There are also problems in the burning of commercial fuels containing various impurities (such as sulfur-containing coal) and problems resulting from the fixation of nitrogen and the lack of satisfactory methods to remove nitrous oxides from the stack gases.

Although the Soviet Union and Japan are actively engaged in MHD research and development, including the construction of a commercial size MHD plant in Moscow, experimental generators in the United States have produced only moderate outputs for short periods of time or small outputs for periods of up to hundreds of hours. In spite of substantial interest in and support of MHD research by the Office of Coal Research of the U. S. Department of the Interior, and the Edison Electric Institute, it does not seem likely that MHD will reach commercial operations in the United States within the next several years.

Electrogasdynamics

Electrogasdynamics (EGD) produces power by passing an electrically charged gas through an electric field. The process converts the kinetic energy of the moving gas to high voltage direct current electricity.

The promise of EGD is similar to the promise of MHD. Units would be smaller, with a minimum of moving parts, would not be limited by thermal cycle efficiencies and would not require cooling water. The system could also be adapted to any source of fuel or energy including coal, gas, oil or nuclear reactors.

Unfortunately, the problems of developing commercially practical units are also similar to those associated with MHD. A pilot plant was constructed in the United States in 1966, but tests on the pilot model uncovered major technical problems and resulted in a termination of the project. In view of these difficulties and the relatively small current effort toward further work on this process, it seems unlikely that EGD will have an impact on the national energy picture within the next twenty years.

Fuel Cells

Fuel cells are electrochemical devices, similar to storage batteries, in which the chemical energy of a fuel such as hydrogen is converted continuously into low voltage electric current. Fuel cells presently under development produce less that 2 volts per cell. In order to create a usable potential, many cells have to be arranged in series and many of these series arrangements must be paralleled in order to produce a significant current. Converters would be required to convert the direct current produced by the cells into alternating current.

The main attractiveness of the fuel cell lies in its modular capability and the possibility of tailoring power output to the immediate needs. Fuel can be stored and used when needed. Losses in transporting fuel are also less that the corresponding losses incurred in transmitting electricity. The efficiency of the direct conversion from chemical to electric energy is high and the heat losses are minimal.

Main problem areas at the present time lie in developing low cost materials of construction and low cost fuels. The most effective electrcdes presently available are platinum electrodes, which can be used in military and space applications, but are not economically competitive for commercial use. Presently used fuels include hydrogen, hydrazine and methyl alcohol. The use of relatively low cost fuels such as coal, natural gas or petroleum is not feasible at this time. Unfortunately, the manufacture of the usable fuels also involves the utilization of significant quantities of electric and other energy, so that the overall benefits are questionable.

A strong effort is being made in the United States to develop the fuel cell for residential and commercial service. A number of prototype units have been installed and are operating successfully. However the fuel cell is not expected to replace a significant portion of the central plant power generation within the next ten years.

Geothermal Generation

Geothermal generation utilizes natural steam or hot water trapped in the earth's crust to produce electrical energy. At the present time, geothermal generation is limited to areas of geothermal activity such as fumaroles, geysers and hot springs. If steam is obtained directly from the earth, it can be used to drive a turbine. Hot water must first be flashed to steam or used to evaporate some other type of working fluid.

Advantages of this type of power generation are that the source of energy is essentially free, although the costs of drilling are not insignificant. Disadvantages are that the steam must first be cleaned and that, at the current state of the art, this scheme is practical only where there is geothermal activity near the surface of the earth. With the advances being made in deep drilling for locating oil, it would seem possible to tap energy sources almost anywhere on earth. However, economic considerations appear to lead to the conclusion that geothermal generation will be feasible only under specially favorable geologic conditions.

Industry Regulation

At the Federal level, numerous agencies have regulatory authority or direct responsibility for certain aspects of the industry. These include the Atomic Energy Commission (AEC), Department of Agriculture, Department of the Interior, Federal Power Commission, the Department of the Treasury, Securities and Exchange Commission, Tennessee Valley Authority, Environmental Protection Agency, U.S. Army Corps of Engineers and the Department of Labor.

The Federal Power Commission (FPC) is authorized to provide certain types of economic regulation over certain investor-owned electric utilities and administrative supervision over certain publicly-owned systems. It licenses all non-Federal hydroelectric projects, regulates all interstate rates and services, and requires systems to keep a specific system of accounts and submit reports on their activities. The annual report FPC Form 67, Steam Electric Plant Air and Water Quality Control Data, with responses from 654 plants, and the Summary Report for the year ended December 31, 1969, formed one of the major sources of data for this report. The 654 plants reporting represented steam electric plants of 25 Mw or greater capacity which were part of a power supply system of 150 Mw or greater and plants of 25 Mw or greater capacity operating in one of the Air Quality Control Regions.

The Atomic Energy Commission (AEC) has the responsibility for licensing construction and operation of nuclear plants (stations). A utility proposing to build a nuclear plant must first apply for a construction permit. With this application the utility must file a Preliminary Safety Analysis Report and an Environmental Impact Statement. After the major design details have been completed, and while construction is under way, the utility has to submit a Final Safety Analysis Report which then becomes the basis for an operating license. In conformance with a recent decision by the United States Court of Appeals, AEC licensing procedures now include consideration of all environmental factors, non-nuclear as well as nuclear, as required by the National Environmental Policy Act (NEPA) of 1969.

At the state level, all states except Minnesota, Nebraska, Texas and South Dakota have regulatory commissions with authority over investor owned utilities. In less than half the states the commissions also have the power to regulate publicly-owned utilities. The degrees of authority vary, but generally include territorial rights, quality of service, safety, and rate-setting. The rate-setting power generally requires a utility to demonstrate to the regulatory authority that a proposed rate structure is necessary in order to permit the utility to earn a return on its equity investment, also known as a rate base. The rate base may be determined from historical cost or fair market value or some other valuation formula, but in most cases, commissions in effect assure the utility of a minimum return on capital invested in its system.

Construction Schedules

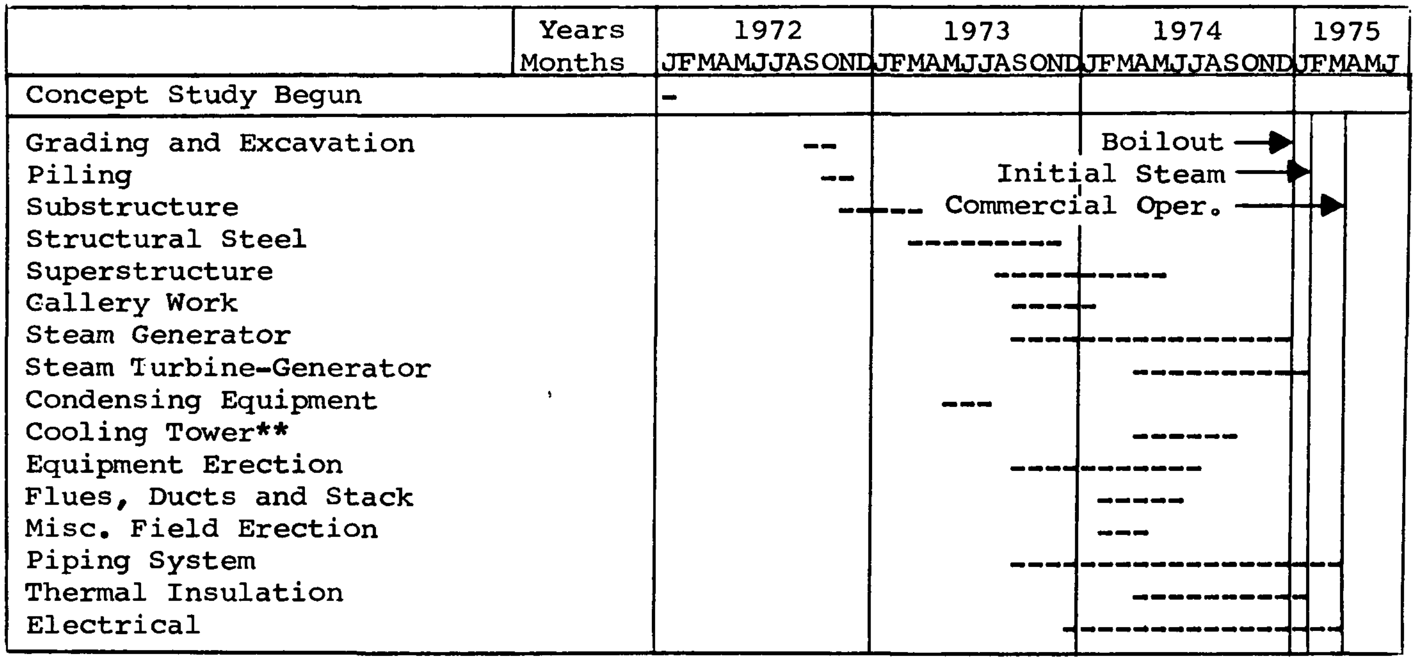
Construction schedules for nuclear plants and fossil-fueled plants are significantly different in the total time span required from the concept study stage to commercial operation. For example, the condensed construction schedule for a 200 Mw oil-fired unit shown in Figure III-2 encompasses a span of about three years from initiation of the concept study to commercial operation. In contrast, Figure III-3 shows excerpts from a typical LWR nuclear plant project schedule. The time span shown from the initiation of the preliminary design until commercial operation is about 8-9 years.

Reliability, Reserve Generating Capacity, and Scheduling of Outages

According to the Federal Power Commission and the National Electrical Reliability Council (References 292, 392 and 396), in order to maintain the uninterrupted service that customers expect and rely upon, all power systems must maintain or have access to more generating capacity than the expected annual peak load. This spare capacity, known as required reserves, changes from time to time and varies widely from system to system, depending on the system size, the sizes and types of generating units in the system, the forced outage rates for these units, maintenance requirements, and system load characteristics.

Figure III-2

CONDENSED CONSTRUCTION SCHEDULE, 200 MW OIL-FIRED UNIT* (Reference No. 187)

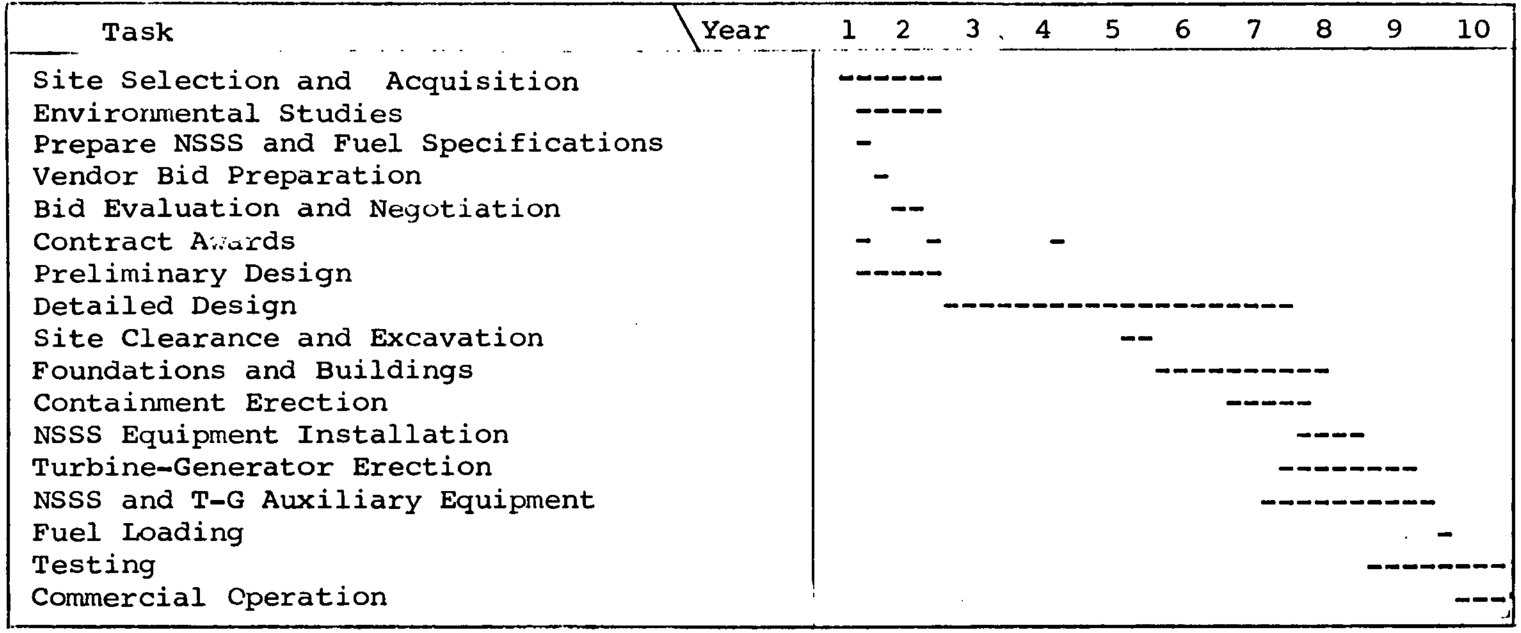


* Note: Base-load type unit with provisions for cycling duty. Major items of equipment include one main transformer, one generator, one steam turbine, one steam condenser, two condensate pumps, five closed feedwater heaters, one deaerating heater, two boiler feedwater pumps, one steam generator, one combustion burner group, and two combustion air fans and compressors.

** Note: Cooling tower is mechanical draft.

Figure III-3

TYPICAL LWR NUCLEAR PLANT PROJECT SCHEDULE (HIGHLIGHTS ONLY)*



* Note: Excerpts from Reference No. 186.

Methods of Determining Reserve Requirements

The planning techniques used by electric utility systems to establish required reserve levels can be divided into two broad categories:

1. Non-probabilistic methods
2. Probabilistic methods

Generating capacity requirements based on a non-probabilistic method have generally been determined by establishing minimum reserve requirements over the annual peak load period based on:

1. A fixed percentage of peak load, or
2. A fixed multiple of the system's largest generating unit, as for example the largest unit plus an average-sized unit.

In the use of these non-probabilistic methods, judgment plays a predominant role. Their only advantage is simplicity, since reserve requirements can easily be calculated once an annual peak load has been projected and the capacity of the largest unit is known. This simplicity of application, however, is offset by the inherent inability of such methods to measure, in a quantitative manner, the system reliability associated with such reserve determinations. In this approach, little consideration is given to the daily, monthly, and seasonal load patterns, or to the characteristics of generating equipment peculiar to the individual system, such as unit availabilities and the mix of unit types and sizes.

Probabilistic methods, although complex, provide an analytical means for evaluating the relative risk associated with supplying system load requirements by various means. This is generally accomplished by interrelating the load and capacity models developed for the particular system and time period under study. The load model usually consists of a series of load levels representing the full range of daily or monthly peak loads anticipated throughout the given period. The model is usually developed from historical records of daily peaks, with adjustments to reflect expected changes in load characteristics of future loads. It may also include provision for the probability of load changes because of deviations from normal conditions of weather or expected economic activity.

The capacity models used in probabilistic method usually involve calculating the likelihood of availability of various levels of system generating capacity, based on assumed forced outage rates for the individual units. The study period is usually divided into uniform maintenance intervals so that units that would not be available for service due to scheduled maintenance would be excluded from the calculations for that particular interval. In effect, this results in a number of capacity models. The interrelation of such capacity models with load models forms the basis for evaluating the risk of capacity not being able to satisfy the load requirements. Sample calculations and more detailed explanations are given in some of the Regional Advisory Committee reports published in Parts II and III of the 1970 National Power Survey.

To illustrate the relationship between reliability and reserve generating capacity consider the two curves in Figure III-4 which are based on studies made by two groups of systems. Assuming an equivalent level of reliability, e.g., one occasion in ten years when, on a probability basis, insufficent generation will be available to cover load, the New England systems require a reserve of about 21% compared with 12% for the MARCA systems. This reflects the differences in type, number, and size of generating units as well as the diversity and composition of load in each instance - all factors which affect generation reserves. Furthermore, the percent reserve requirements can be expected to change with time, reflecting varying conditions.

Reserves for Scheduled Outages

Generating units are taken out of service at fairly regular intervals for inspection, overhaul, and repair as required. This practice accounts for the relatively high reliability of generating capacity. When conditions are such on an electric system that generating capacity needed to supply load must be taken out of service, generating capacity from reserves must be provided tc take its place. The amount of reserves needed at time of peak load depends on the duration of maintenance outages and whether the work can be scheduled during offpeak months.

There are variations from year to year in the amount of scheduled maintenance that a generating unit requires, and some types of inspection and repair are needed only at two or three year intervals. There are also variations in intervals between scheduled outages and in downtime for maintenance because of such factors as age, size and type of unit. On the average, baseload boiler-turbine-generator units require about one month of scheduled maintenance per year.

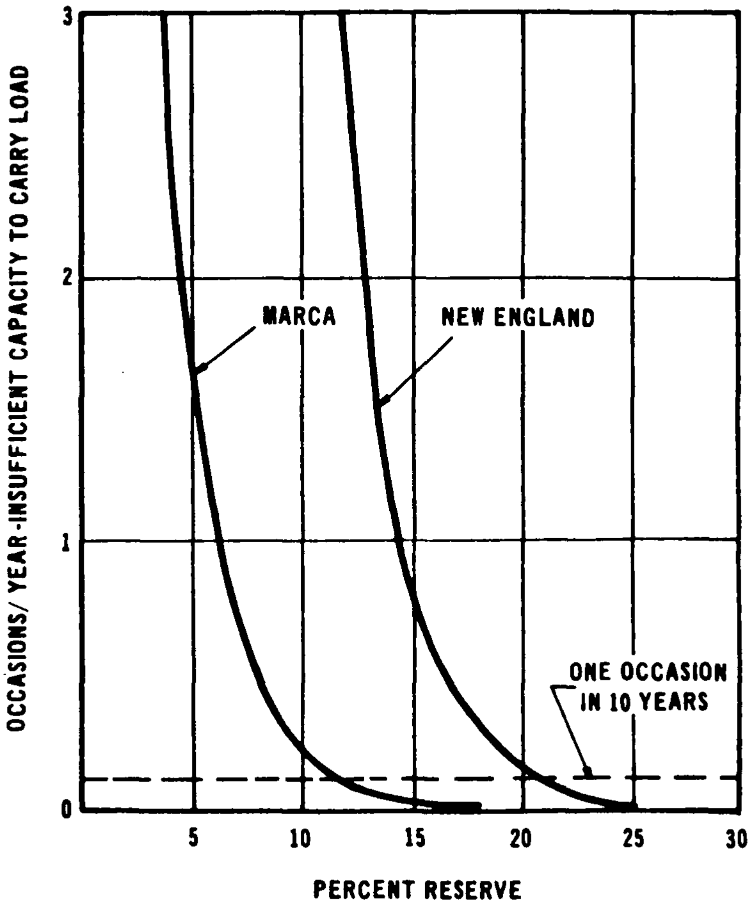


Figure III-4 Regional Reliability[392] Versus Percent Reserve

In general, the relatively large generating units will be operated at higher use factors and will require more time for maintenance than the smaller units. For the purpose of the Federal Power Commission analysis of 1980 reserve for scheduled outages, the large size thermal units, 600 megawatt or over, were assumed to require 600 hours of scheduled maintenance annually while units of 200 megawatt to 599 megawatt size were assumed to require 500 hours, and units under 200 megawatt, 400 hours.

In estimating the amount of reserve required for scheduled maintenance, it is necessary to determine whether there is enough time and spare capacity to take all units out of service for their scheduled overhaul during off-peak months. In actual practice, such a determination would involve extensive calculation if there were many units in the system and the scheduling were tight. Various combinations would be explored to determine the optimum schedule in terms of utilizing the spare capacity available in generating units of different sizes for each interval.[396] Reference 395 gives an example of a model for the optimization of outage costs. At the same time the maintenance schedule should provide for reasonable use of the crews and not result in excessive loading on parts of the transmission system. A further factor is that the generating capacity of a system may change month by month because of retirements, additions, cooling water limitations, and seasonal changes in the output capability of installed hydro-electric units.

Coordination for Reliability

Most of the text of this discussion is exerpted from Reference 292, from the Federal Power Commission.

Nearly every major electric utility system in the United States is connected with neighboring systems to form large interconnected networks. Financial benefits are thereby often realized from staggered construction of large generating units, short-term capacity transactions, and interchanges of economy energy. Reduction of installed reserve capacity is made possible by mutual emergency assistance arrangements and associated coordinated transmission planning. Bulk power supply reliability is enhanced by interconnection agreements covering spinning reserves, reactive kilovolt-ampere requirements, emergency service, coordination of day-to-day operations, and coordination of maintenance. The satisfactory performance of a power supply network requires close cooperation among component systems for accurate control of frequency, sharing of load regulating responsibilities and maintenance of power system stability.

There are thousands of arrangements among systems from all segments of the industry providing for various degrees and methods of electrical coordination. These variations reflect differences in load density, characteristics of generating sources, geography, and climate. They are also a product of managerial views with respect to planning, marketing, competition, and retention of prerogatives. Because of these differences, no single definition of coordination has been established by the electric utility industry. As used in this discussion "coordination" is joint planning and operation of bulk power facilities by two or more electric systems for improved reliability and increased efficiency which would not be attainable if each system acted independently. "Full coordination" involves coordination of all systems within an area, to the extent technologically and economically feasible to permit the serving of their combined loads with a minimum of resources and to exploit opportunities for coordination with adjacent areas.

Managements of various electric systems have developed a wide variety of formal and informal coordinating organizations or power pools. Some merely provide members with a mechanism for the exchange of information; others deal primarily with day-to-day interconnected operations under normal and abnormal system conditions; many engage in coordinated planning and operation for increased economies; and still others are dedicated to improving reliability over broad geographic areas encompassing otherwise unaffiliated electric systems. All of these organizations contribute in varying degrees to the reliability and economy of electric power supply.

The term "formal power pool" as used here means two or more electric systems which coordinate the planning and/or operation of their bulk power facilities for the purpose of achieving greater economy and reliability in accordance with a contractual agreement that establishes each member's responsibilities. Individual members usually are able to obtain the economies and other advantages available to much larger systems while retaining their separate corporate identities.

Table A-2-1 of Appendix 2 lists the individual members of each formal power pool in the contiguous United States. The areas served by formal power pools cover most of the United States as shown in Figure A-2-1 of Appendix 2.

A power pool must have sufficient generating capacity to meet the combined pool load plus reserve to cover equipment outages, frequency, regulation, load swings, errors in forecasting loads, and slippage in planning and construction schedules. The various pools make specific provision for sharing among the pool participants the burden of providing this reserve margin. There are, in general, two different methods of accomplishing this objective. Under one, each member is required to maintain a specified minimum capacity reserve, usually stated in percent of peak load. Under the other, existing installed generating capacity is shared on an equalized reserve basis. That is, rather than each member being responsible for maintaining some minimum amount of reserve, the reserve capacity of the pool is shared proportionally among the members. Reserve responsibility is satisfied by capacity transactions so that members with excess capacity resources are compensated by members having capacity deficiencies.

There are at least 13 informal organizations of utilities in the contiguous United States which are structured to emphasize some limited aspects of inter-system coordination. These coordinating groups are informal in the sense that no member is contractually obligated to undertake any specific course of action or to provide any kind of service to other members. The groups are usually concerned primarily either with planning or operation, although some are active in both. The geographic areas covered by these groups are shown in Figure A-2-2 of Appendix 2. Table A-2-2 of Appendix 2 lists each group, its acronym, and the individual members. Twenty-four individual systems, as shown in Table A-2-3 of Appendix 2, are members of two or more informal coordinating groups.

The National Electric Reliability Council (NERC) was formed in 1968 for the purpose of further augmenting the reliability and adequacy of bulk power supply by the electric systems of North America. It consists of nine regional reliability councils whose membership comprises essentially all of the power systems in the United States and the Canadian systems in the provinces of Ontario, British Columbia, Manitoba, and New Brunswick.

Each council has established a mechanism to provide for direct or indirect participation by the smaller electric utilities within its boundaries. The approximate geographic boundaries of the councils are shown on Figure A-2-3 of Appendix 2, and the individual members of each council are shown in Table A-2-4 of Appendix 2.

None of the reliability councils has authority to make decisions involving the planning or installation of new bulk power facilities, but most have a formal review and approval role. Seven reliability councils have adopted criteria for testing the design and operation of existing and proposed bulk power facilities and the other two have established committees to formulate such criteria. Several councils have adopted procedures for reporting by members of uniform compatible data on load estimates, scheduled maintenance, power exchanges, and installed reserve margins. A few have developed guides and regionally coordinated programs covering daily operating reserve margins, emergencies on the interconnected system, uniform rating of generating equipment, and principles of relaying. Some regional councils have established environmental committees to encourage more effective consideration of environmental matters in the siting, construction, and operation of major facilities.

The Federal Power Commission's Statement of Policy on Reliability and Adequacy of Electric Service, Order No. 383-2 (Docket No. R-362), issued April 10, 1970, is intended to implement fully the voluntary aspects of Section 202(a) of the Federal Power Act, and to encourage utilities throughout the Nation to continue to strengthen the reliability councils and develop more effective bulk power supply programs. The Commission Order requested participation by the staffs of the Commission and appropriate State commissions as non-voting participants in the principal meetings of NERC and the regional councils, and requested regional councils to report the projection of loads and coordinated bulk power supply programs on a ten-year basis. It also requested reports on the status of consultations with affected groups and appropriate local, State, and Federal authorities regarding the environmental impact of proposed major facilities, and information on load flow studies, network stability analyses, principal communication and control systems, and coordinated regional programs pertaining to provisions for emergencies, scheduled maintenance outages of major facilities, and other matters which affect the overall reliability of the interconnected network. Initial reports were filed as of September 1, 1970. Future reports to be filed on April 1 of each year provide opportunity for updating the power supply programs in the ten-year framework to reflect revisions in load estimates, new developments and resources, and the resolution of environmental issues.

In April 1962, representatives of interconnected systems throughout the United States and eastern Canada met at

Omaha, Nebraska, and laid the groundwork for an international organization to coordinate the operation of a looming coast-to-coast interconnected network. This led to formation of the North American Power Systems Interconnection Committee (NAPSIC) which held its first meeting in January, 1963. NAPSIC is a voluntary organization of operating personnel representing ten interconnected Operating Areas. The scope of the organization has expanded so that by 1971 it included consideration of the following:

1. Operating reliability criteria,
2. Frequency regulation,
3. Time control,
4. Tie-line frequency bias,
5. Operating reserves,
6. Time error correction procedures,
7. Emergency operating procedures
    (a) Load shedding and restoration
    (b) Tie separation and restoration
    (c) Generating unit security,
8. Scheduled maintenance outages of major facilities
9. Interchange scheduling procedures,
10. Procedures, for handling inadvertent interchange,
11. Any other operating matters that required coordination to effect reliable interconnected operation.

NAPSIC's contribution to reliable system performance is enhanced by its close liaison with planning entities, regional reliability councils, and the National Electric Reliability Council. Much of the reliability council work overlaps activities which are the concern of the Operating Areas within NAPSIC. Close working relationships which have been established between these different organizational units provide the opportunity for very effective coordination between planning and operating functions.

Coordinating Techniques

Over the years electric utilities have developed a wide variety of coordinating techniques to achieve increased reliability and improved economies. Some of the major coordinating techniques are described below.

Staggered construction is a technique which involves construction of excess capacity by one utility for the use of one or more other utilities with the supplier-buyer arrangement being reversed or modified with each succedding unit. Several variations of this practice are widely used. Sometimes adjacent systems informally coordinate their capacity additions over a period of several years so that the total installed capacity reserve approximates the amount required by the entire geographic area. Another form of staggered construction which has gained widespread acceptance in recent years is the unit-sale concept. This entails arrangements whereby a system installs a larger unit than it otherwise normally would, and sells a specified amount of excess capacity from that unit to one or more neighboring systems. The purchaser's entitlement is limited to the availablity of capacity from the specific unit. In the event of an outage of such unit, the buyer is not entitled to any portion of the supplier's other capacity resources.

Seasonal capacity exchanges can usually be made when the annual peak loads of two utilities, areas, or regions occur in different seasons of the year. However, individual systems within the same power pool having annual peak demands which occur in different months do not normally participate in seasonal capacity exchanges because, in a pool, savings from intrapool diversity are automatically achieved by the decreased total installed reserve requirements resulting from the pool operation.

Small Systems

For the purpose of providing a statistical frame of reference, small electric systems were defined in the 1964 National Power Survey as those having annual peak-hour demands of less than 25 megawatts. By this definition there were 3,190 small systems in 1962, of which 899 generated all or part of their requirements and 2,291 purchased their entire requirements. By 1968 the total number of small systems decreased to 2,842, a reduction of 348, principally as the result of acquisitions and mergers. More than 800 of the remaining small systems owned generating facilities, and 243 were electrically isolated from major transmission networks.

The total cost of generation at the bus bar for the sizes of plants usually installed by small systems is relatively high because such plants cost more per kilowatt to build, burn more fuel per kilowatt-hour, and cost more per kilowatt-hour to operate. The ability to take full advantage of modern generation and transmission technology is often limited to the larger systems. Only 31 systems with generating capacity of less than 500 megawatts are members of formal power pools.

Since the cost gap between small scale and large scale generation and transmission has been progressively widened by technological improvement, most of the smaller electric systems which generate the bulk of their electric requirements are at a relatively greater economic disadvantage than they were during the 1950's and the early 1960's. Benefits from coordinated planning are being realized by some of these smaller system through joint ownership, or entitlements in large, more efficient generating units sized to meet area needs, and through associate or affiliate membership in regional councils. Systems which serve their growing needs by power purchases receive reliability and economic benefits when their power suppliers participate in area-wide and regional coordination.

Many small systems buy all of their power requirements at wholesale, although they have the option to plan, install, and operate bulk power facilities. A heavy concentration of these distribution systems within a specific geographic area increases the chances of economic feasibility for them jointly to plan and construct their own bulk power system, but such endeavors may result in duplication of faciities unless suitable wheeling arrangements can be worked out with neighboring, and generally competing, systems.

Small systems having generating facilities, but with sufficient capacity to meet their total electric requirements, include: (1) those having only a small amount of generation (often, hydro) which is supplemented with purchases from a neighboring supplier (2) systems which plan gradually to phase themselves out of the generating business but still have one or more units in serviceable condition; and (3) systems that use small units for peak shaving to reduce average purchased power costs. There is a wide variety of bilateral arrangements covering such situations This type of system will continue to be a part of the overall supply, primarily because it provides an intermediate step in moving to or from full within-system generation.

Some small systems have sufficient generation to meet their own requirements and operate in complete electric isolation, or with interconnection facilities normally open. Others are connected to and operate in parallel with major power networks, under a wide variety of agreements. In recent years, some small systems have been able to negotiate lower reserve requirements through coordination of their operations with neighboring systems, and a few have gained access to large scale generation.

At the beginning of 1968, 243 systems were electrically isolated from power supply networks. Approximately 82 1/2 percent of the total generating capacity of the isolated systems was located in eight states (Florida, Illinois, Kansas, Louisiana, Massachusetts, Mississippi, Ohio and Texas).

Isolated systems typically experience relatively high power supply costs and inferior bulk power reliability. About 75 percent of the isolated systems in 1966 carried reserve capacity greater than 50 percent of their annual system peak demands. On such systems the forced outage of a generating unit may represent loss of such a large portion of on-line capacity that partial or total power failure may result before other units can respond to meet the increased load placed upon them. Also, an isolated system is vulnerable to extended service interruption if fire, natural disaster, or other catastrophe destroys one or more of its major generating plants.

SECTION IV

INDUSTRY CATEGORIZATION

The purpose of this section is to establish a framework for the orderly development of effluent limitations guidelines and standards in consideration of waste water characteristics, pollutant parameters, control and treatment technology, cost, energy, non-water quality aspects, and other factors as presented in subsequent sections. The rationale supporting the recommended industry subcategorization and effluent limitations guidelines and standards is presented in Sections IX, X, and XI of this document.

Steam electric powerplants are characterized by many diverse aspects, and at the same time by many similarities. Categorization of the industry into discrete segments for the purpose of establishing effluent limitations guidelines requires consideration of the various factors causing both this diversity and similarity. Specific factors which require detailed analysis in order to categorize the industry include the processes employed, raw materials utilized, the number and size of generating facilities, their age, site characteristics and mode of operation.

Process Considerations

There are five major unit processes involved in the generation of electric power - the storage and handling of fuel related materials both before and after usage, the production of high-pressure steam, the expansion of the steam in a turbine which drives the generator, the condensation of the steam leaving the turbine and its return to the boiler, and the generation of electric energy from the rotating mechanical energy. Figure IV-1 shows a schematic flow diagram of a typical steam electric powerplant. Power cycle diagrams for typical fossil fuel units and nuclear units are shown in Figures IV-2, and IV-3, respectively.

Fuel Storage and Handling

All fuels must be delivered to the plant site, stored until usage, and the spent fuel materials stored on the premises or removed. Fossil-fueled plants require off-loading facilities and fuel storage in quantities based on the size of the plant and the limited reliability of delivery. Fossil-fuels are transported to the furnace where combustion

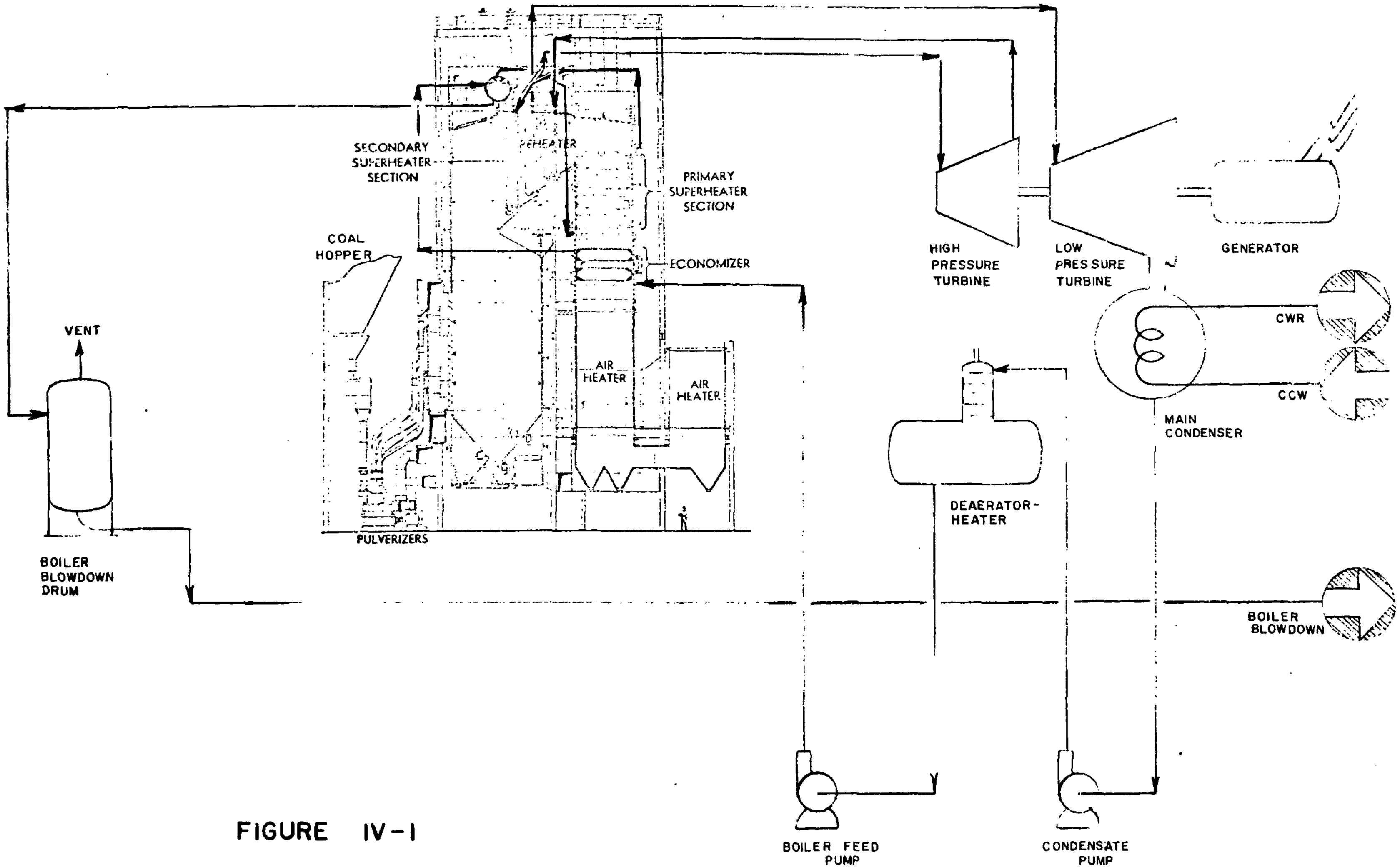


FIGURE IV-1

SCHEMATIC FLOW DIAGRAM

TYPICAL STEAM ELECTRIC GENERATING PLANT

Table II-1

SUMMARY OF EFFLUENT LIMITATIONS GUIDELINES AND STANDARDS FOR POLLUTANTS OTHER THAN HEAT

SOURCE	POLLUTANT PARAMETER	EFFLUENT LIMITATIONS*		
		BPCTCA (1977)	BATEA (1983)	New Sources
Nonrecirculating cooling water	Free available chlorine	←	0.2 (0.5 max) **	→
	Total residual chlorine		**	
Cooling tower blowdown	Free available chlorine		0.2 (0.5 max) **	
	Total residual chlorine		**	
	Chromium, total	No limitation	0.2 (0.2 max)	-
	Zinc, total		1.0 (1.0 max)	-
	Total phosphorus (as P)		5.0 (5.0 max)	-
	Corrosion inhibiting materials other than Cr, Zn, and P		Case-by-case	-
	All corrosion inhibiting materials		-	No discharge
Ash transport	Total suspended solids	30 (100 max)	-	-
	Oil and grease	15 (20 max)	-	-
Bottom ash transport	Total suspended solids	-	2.4 (8.0 max)	1.5 (5.0 max)
	Oil and grease	-	1.2 (1.6 max)	0.75(1.0 max)
Fly ash transport	Total suspended solids	-	30 (100 max)	No discharge
	Oil and grease	-	15 (20 max)	No discharge
Low-volume wastes				
Boiler blowdown	Total suspended solids		30 (100 max)	
	Oil and grease		15 (20 max)	
	Copper, total		1.0 (1.0 max)	
	Iron, total		1.0 (1.0 max)	
Metal equipment cleaning wastes	Total suspended solids		30 (100 max)	
	Oil and grease		15 (20 max)	
	Copper, total		1.0 (1.0 max)	
	Iron, total		1.0 (1.0 max)	
Others, except sanitary wastes and radwastes	Total suspended solids	←	30 (100 max)	→
	Oil and grease		15 (20 max)	
Rainfall runoff from materials storage piles and construction activities	Total suspended solids		Not to exceed 50mg/l	
Rainfall runoff from other sources ***	All pollutant parameters		No limitation	
Sanitary wastes and radwastes	All pollutant parameters		No limitation	
All sources	Polychlorinated biphenyls		No discharge	
	pH value ****		Within the range 6.0-9.0 at all times	

* Note: Numbers are concentrations, mg/l, except for pH values. Effluent limitations, except for pH and rainfall runoff, are quantities of pollutants to be determined by multiplying the concentration indicated times the flow of water from the corresponding source. Effluent limitations are averages of daily values for 30 consecutive days (maximum values for any one day are determined from the numbers in parentheses), except for pH and rainfall runoff. In the event that waste streams from various sources are combined for treatment or discharge, the quantity of each pollutant attributable to each waste water source shall not exceed the limitation for that source. No limitations are prescribed for sources/pollutants not specified in this table.

** Note: Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours (aggregate) in any one day and not more than one unit in any plant may discharge free available chlorine or total residual chlorine at any one time. Exceptions to be made, on a case-by-case basis, if discharger demonstrates that limitations must be exceeded in order for the cooling system to operate efficiently.

*** Note: ...and from facilities designed, constructed, and operated to treat the volume of material storage runoff and runoff from construction activities that is associated with a 10 year, 24 hour rainfall event.

**** Note: From all sources except nonrecirculating cooling water, rainfall runoff from sources other than materials storage piles and construction activities ***, sanitary wastes and radwastes.

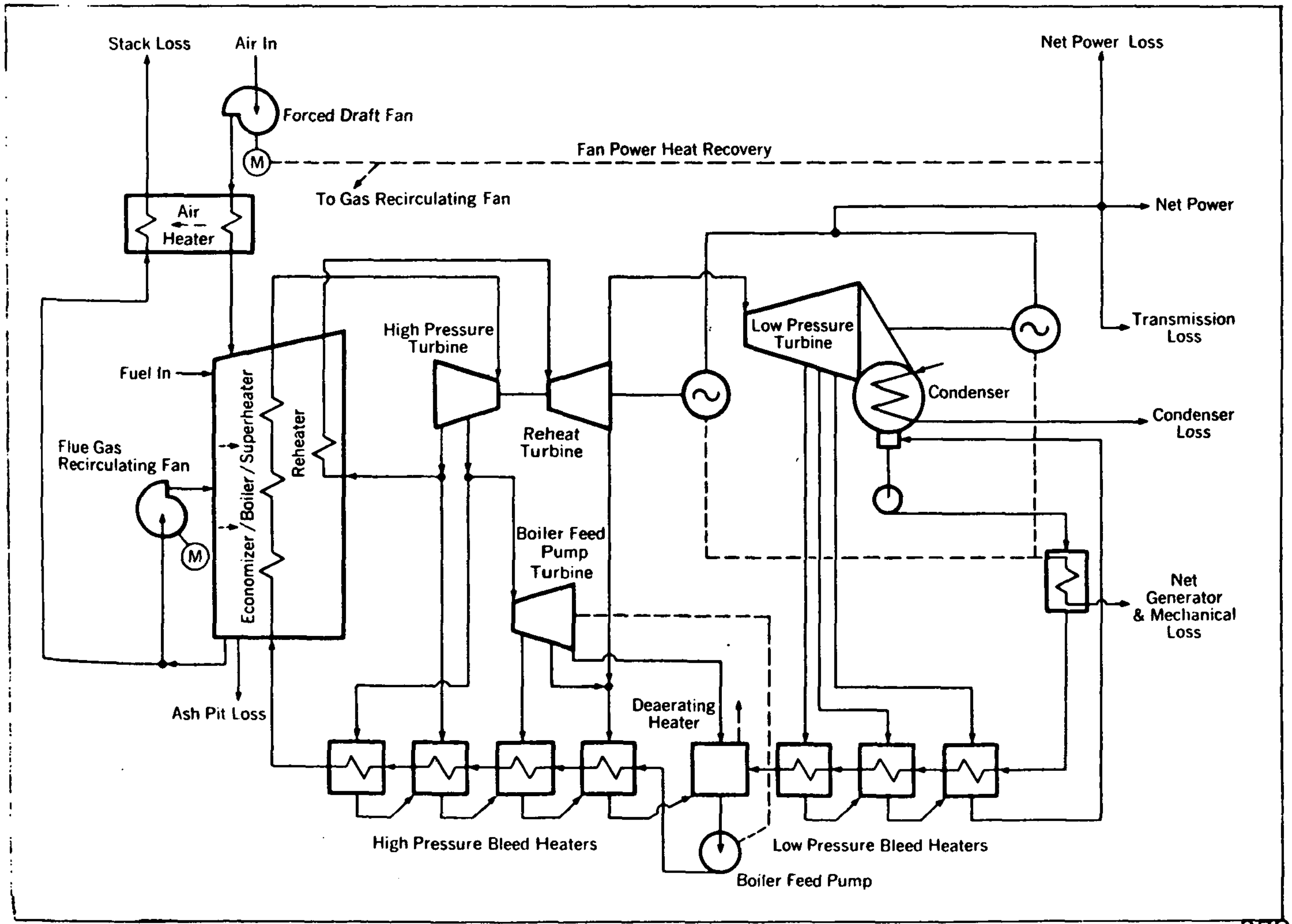


Figure IV-2 Power cycle diagram, fossil fuel — single reheat, 8-stage regenerative feed heating — 3515 psia, 1000F/1000F steam.

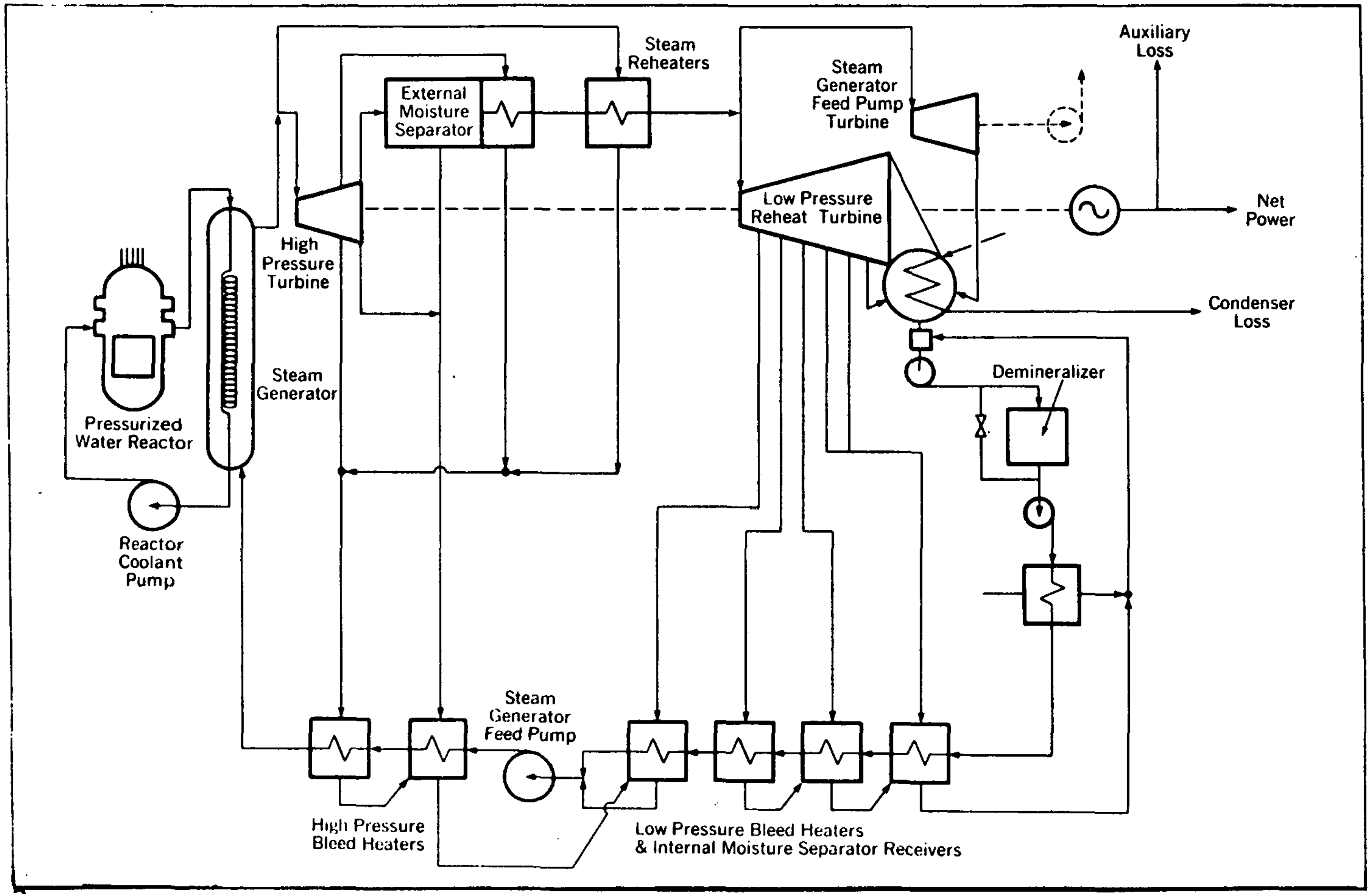


Figure IV-3 Power cycle diagram, nuclear fuel — reheat by bleed and high pressure steam, moisture separation, and 6-stage regenerative feed heating — 900 psia, 566F/503F steam. 278

takes place. The combustion of fossil fuels results in gaseous products of combustion and non-gaseous non-combustible residues called ash. A portion of the ash is carried along with the hot gases. This portion is referred to as fly ash. The remainder of the ash settles to the bottom of the furnace in the combustion zone and is called bottom ash. The amount and characteristics of each type of ash is dependent on the fuel and the type of boiler employed. Coal produces a relatively large amount of bottom ash and fly ash. Oil produces little bottom ash but substantial fly ash. Gas produces little ash of any type.

Coal-fired steam generators can be categorized as wet or dry bottom according to ash characteristics. Gas-fired and oil-fired steam generators are generally run with dry bottoms. In one type of wet bottom steam generator the coal is burned in such a manner as to form a molten slag which is collected in the bottom and is tapped off similar to the tapping of a blast furnace. In dry bottom steam generators, where ash is removed hydraulically, it is customary to pump the ash slurry to a pond or settling tank, where the water and ash are separated.

Many modern powerplants remove fly ash from the gaseous products of combustion by means of electrostatic precipitators, although scrubbers may be required on plants burning fossil fuels containing more than a minimal amount of sulfur. The removal of fly ash collected in an electrostatic precipitator depends on the method of ultimate disposal. If the fly ash is to be used in the manufacture of cement or bricks or otherwise used commercially, it is generally collected dry and handled with an air conveyor. If it is to be disposed of in an ash pond or settling basin, it is sluiced out hydraulically.

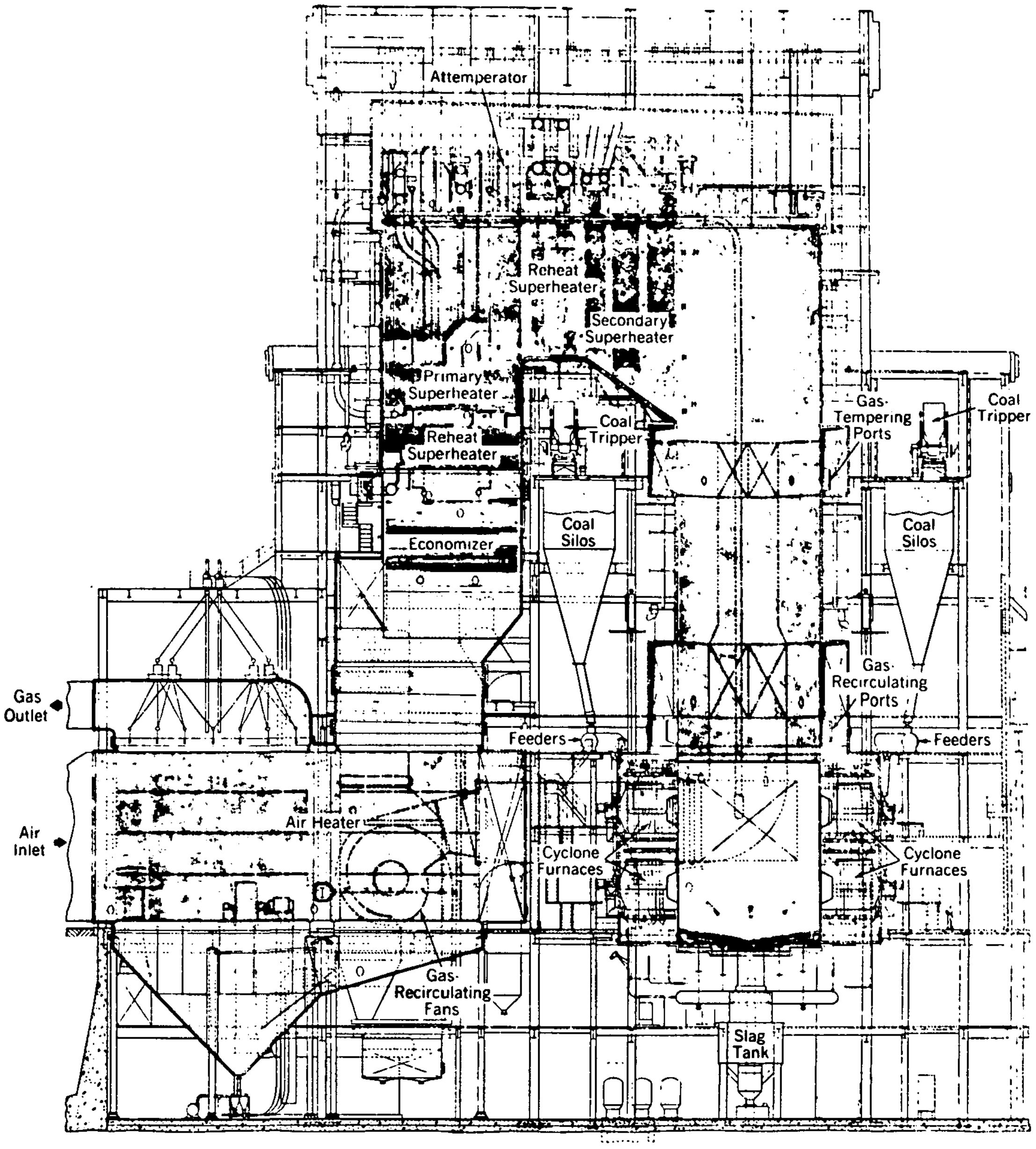
Many of the operations involving fossil-fuels are potential sources of water pollutants. The storage and handling of nuclear fuels in comparison is not a continuous operation, requires little space, is highly sophisticated from the standpoint of engineering precision and attention to details, and is not considered to be a potential source of nonradiation water pollutants.

Steam Production

The production of high-pressure steam from water involves the combustion of fuel with air and the transfer of the heat of combustion from the hot gases produced by the combustion to the water and steam by radiation and convection. In order to obtain the highest thermal efficiency, as much of the heat of combustion as possible must be transferred from the gases to the steam and the gases discharged at the lowest possible temperature. This requires the transfer to be accomplished in a series of steps, each designed for optimum efficiency of the overall process. Not every boiler provides each of the steps outlined in this section, but most of the boilers supplying steam to larger and newer generating units (over 200 Mw and built in the last twenty years) provide these steps as a minimum. A typical boiler for a coal-fired furnace is shown in Figure IV-4.

Feedwater is introduced into the boiler by the boiler feed pump and first enters a series of tubes (regenerative feedwater heater) near the point where the gases exit from the boiler. There it is heated to near the boiling point. The water then flows to one or more drums connected by a number of tubes. The tubes are arranged in vertical rows along the walls of the combustion zone of the boiler. In this zone, the water in the tubes is vaporized to saturated steam primarily by the radiant heat of combustion. The saturated steam is then further heated to higher temperatures primarily by convection of the hot gases in the superheater section of the boiler. In some boilers, the steam is reheated after passage through the initial sections of the turbine. Finally, the flue gases are passed through a heat exchanger (air heater) in order to transfer heat at a low temperature to the air being blown into the boiler.

As far as steam production is concerned, the efficiencies possible from the conversion of the chemical energy of the fuel to electric energy depend on the maximum steam temperatures and pressures and on the extent of the utilization of regeneration feedwater heaters, reheat and air heating. For a simple cycle using saturated steam with a maximum pressure of 6.3 MN/sq m (900 psi) expanded in the turbine to atmospheric pressure and using exhaust steam to heat the feedwater, the total cycle efficiency would be about 20%. If the saturated steam is superheated to 530°C (1,000°F), the efficiency is increased by an increment of 5 to 6%. The addition of a high-vacuum (863 kg/sq m (2-1/2 in. of Hg abs)) condenser and the addition of feedwater heating will increase possible efficiencies by an increment of 12 - 13% to about 38%. By increasing the maximum pressure still further and reheating the steam, the efficiency can be increased to about 45%. These are turbine cycle efficiencies and do not reflect various losses in the boiler and auxiliary power requirements. Indications are that these efficiencies represent the limit obtainable from the processes presently in use. Higher efficiencies which require higher steam pressures and temperatures would



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Universal-Pressure boiler with opposed Cyclone Furnaces and bin system for coal preparation and feeding.

Figure IV-4 Typical Boiler for a Coal-Fired Furnace present material problems that do not seem to be near solution. The alternate of lower terminal temperatures is not possible since the waste heat must be rejected to the environment under ambient conditions, unless economical techniques could be developed to reject waste heat to the low temperature of outer space.

In the effort to improve the efficiency of the steam cycle, designers have attempted to resort to higher temperatures and pressures. Maximum turbine operating pressures increased from about 1,000 psi in the early 1930's to 5,000 psi in the early 1960's. Since then, turbine design pressures for new units have receded slightly to a maximum of 3500 psi. Similarly, maximum operating temperatures increased from 800°F to 1200°F for a brief period and then receded to a maximum of 1050°F, as designers looked to more sophisticated reheat cycles and turbine designs to optimize plant performance.

Nuclear generators presently in operation fall into two classes, pressurized water reactors (PWR) and boiling water reactors (BWR). In a PWR, water under a pressure of about 14 MN/sq m (2,000 psig) is heated as it circulates past the nuclear fuel rods in a closed loop. This hot water then exchanges heat with a secondary water system which is allowed to vaporize to steam. In the BWR, water heated in the reactor core under a pressure of about 7 MN/sq m (1,000 psig) is allowed to vaporize to steam directly. Neither of these processes produce steam with significant amounts of superheat and this limits their thermal cycle efficiencies to about 30%.

The size or rating of boilers is in terms of thousands of pounds of steam supplied per hour. According to the FPC the increase in boiler capacity was rather slow until 1955, when the maximum capacity of boilers installed began to rise from a level of about 1,500 thousand pounds per hour to the present level of about 10,000 thousand pounds per hour. Prior to 1950, individual boilers were kept small, in large part because boiler outages were rather numerous, so that it was common design practice to provide multiple boilers and steam header systems to supply a turbine-generator. Some plants report to the FPC that the steam headers are connected to multiple turbine-generators. Advances in metal technology since 1950, with associated lower costs of larger units, have made it economical and reliable to have one boiler per turbine-generator.

Steam Expansion

The conversion of the pressure energy of the steam into mechanical energy occurs in the steam turbine. In the turbine the steam flows through a succession of passages made up of blades mounted on alternately moving and stationary discs. Each set of moving and stationary discs is called a stage. The moving discs are mounted on a rotating shaft while the stationary discs are attached to the turbine casing. As the steam passes from disc to disc, it gives up its energy to the rotating blades and in the process loses pressure and increases in volume. If the steam enters the turbine in a saturated condition, a small portion of the steam will condense as it passes through the turbine. One reason for superheating or reheating steam is to reduce this condensation and the mechanical problems associated with it.

There are many different types of turbines and turbine arrangements in use in steam electric powerplants. Almost all turbines in use in central generating plants are of the condensing type, discharging the steam from the last stage at below atmospheric pressure. The efficiency of the turbine is highly sensitive to the exhaust pressure (backpressure). A turbine designed optimally for one level of backpressure will not operate as efficiently at the other levels of backpressure. Some turbines designed for 863 kg/sq m (2-1/2 in. of Hg abs) backpressure cannot operate at 1,730 kg/sq m (5 in. of Hg abs) because of high temperature in the last stages. In general, turbines designed for once-through cooling systems will generally be operated at lower backpressures than those designed for closed cooling systems. Moreover, if a turbine designed for the low backpressures corresponding to once-through cooling system is operated instead with a closed cooling system, an incremental decrease in turbine efficiency will result during times when the back pressure is higher than it would have been for once-through cooling.

In most turbine arrangements a portion of the steam leaves the casing before the final stage. This type of turbine is called an extraction turbine. The extracted steam is used for feedwater heating purposes. In some turbines, a portion of the steam is extracted, reheated in the boiler, and returned to the turbine or to another turbine as a means of improving overall efficiency. Many different mechanical arrangements of high pressure and low pressure turbines on one or more shafts are possible, and have been utilized.

While there are no major effluents associated with the steam expansion phase other than those resulting from housekeeping operations, the significance of the steam expansion lies in its effect on plant efficiency and therefore on the thermal discharge. In many plants, turbine design will be a key factor determining the extent of the feasibility of converting a once-through cooling system to a closed system.

Steam Condensation

Steam electric powerplants use a condenser to maintain a low turbine exhaust pressure by condensing the steam leaving the turbine at a temperature corresponding to vacuum conditions, thus providing a high cycle efficiency and recovering the condensate for return to the cycle. Alternatively, the spent steam could be exhausted directly to the atmosphere thus avoiding the requirement for condensers or condenser cooling water, but with poor cycle efficiency and a requirement for large quantities of high purity water. There are two basic types of condensers, surface and direct contact. Nearly all powerplants use surface condensers of the shell and tube heat exchanger type. The condenser consists of a shell with a chamber at each end, connected by banks of tubes. If all of the water flows through the condenser tubes in one direction, it is called a single-pass condenser. If the water passes through one half of the tubes in one direction and the other half in the opposite direction, it is called a two-pass condenser. Steam passed into the shell condenses on the outer surface of the cooled tubes.

A single-pass condenser tends to require a larger water supply than a two-pass condenser and will generally result in a lower temperature rise in the cooling water. In most instances it will also produce a lower turbine backpressure. A two-pass condenser is utilized where the cooling water supply is limited or in a closed system where it is desired to reduce the size of the cooling device, and improve its efficiency by raising the temperatures of operation.

Many condensers at the more-recently built powerplants have divided water boxes so that half the condenser can be taken out of service for cleaning while the unit is kept running under reduced loads. Since cleanliness of the condenser is essential to maintaining maximum heat transfer efficiency, it is common practice to add some type of biocide to the cooling water to control the growth of algae or slimes in the condenser. In spite of these biocides most powerplants clean condensers mechanically as part of regularly scheduled maintenance procedures. Some plants employ continuous on-line mechanical cleaning systems.

Operation of the condenser requires large quantities of cooling water. Wherever adequate supplies of cooling water are available, it has been common practice to take cooling water from a natural source, pump it through the condenser, and discharge it to the same body of water from which it was obtained. This is known as a "once-through" system. One of the major considerations in siting powerplants is the availability of an adequate source of high-quality once-through cooling water. If sufficient water for a once-through system is not available and other considerations prevail in determining the location of the plant, cooling water must be recirculated within the plant. In this case some form of cooling device, an artificial pond with or without sprays, or a cooling tower must be provided to keep the temperature from rising above the maximum level permissible or desirable for turbine operation. Figure IV-5 shows a schematic flow diagram of a typical recirculating (closed) system utilizing cooling towers. For reasons of economy closed systems typically operate at higher temperature differentials across the condenser than once-through systems, balancing the somewhat reduced efficiency of the turbine against the lower quantity of cooling water required, and therefore the smaller size and lower cost of the cooling device. However, since nearly all cooling devices currently in use obtain their cooling effect from evaporation, the dissolved solids concentration of closed cooling systems tends to increase, eventually reaching, if uncontrolled, a point where scaling of the condenser would interfere with heat transfer. A portion of the concentrated circulating water must therefore be discharged continually as blowdown to remove dissolved solids, and purer fresh water must be provided to make up for losses due to evaporation, blowdown, liquid carryover (drift), and leaks.

Flow rates of cooling water vary with the type of plant, its heat rate and the temperature rise across the condenser. A fossil plant with a heat rate of 10,000 kJ/kwh (9,500 Btu per kwh) and a 6.7°C (12°F) rise across the condenser (values typical of plants in the industry using once-through cooling systems) will require about 0.5 x 10^{-4} cu m/sec (0.8 gpm) of cooling water for every kw of generating capacity. A nuclear plant with a heat rate of 11,100 kJ/kwh (10,500 Btu per kwh) and a 11°C (20°F) rise across the condenser, (typical of plants using closed cooling systems) will require about 0.46 x 10^{-4} cu m/sec (0.73 gpm). Because of differences in thermal efficiencies, nuclear plants under identical conditions require about 50% more cooling capacity than comparible fossil plants.

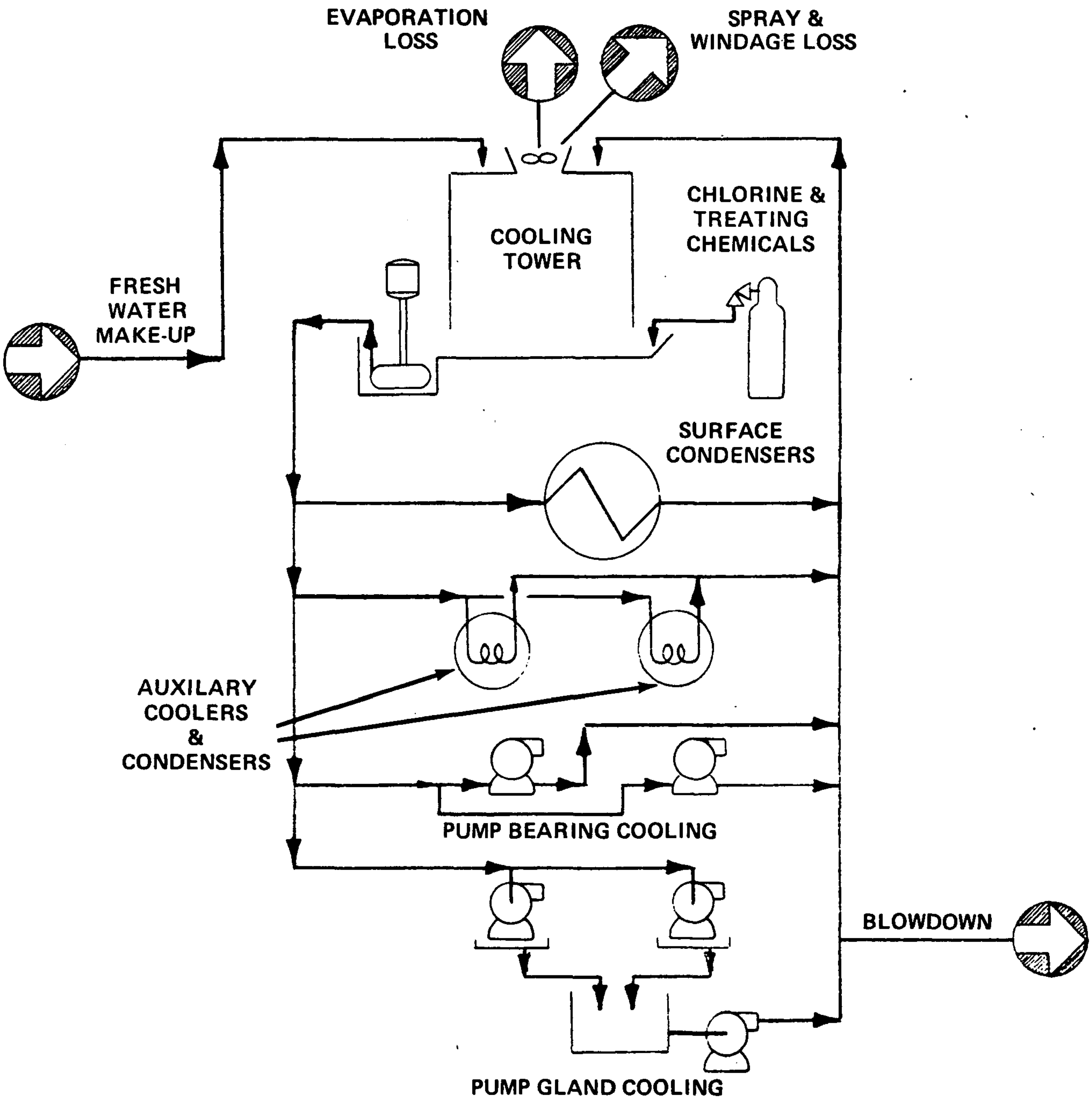


FIGURE IV-5 SCHEMATIC COOLING WATER CIRCUIT

While both once-through and closed cooling systems are currently in use in the industry, the use of closed systems has generally been dictated by lack of sufficient water supplies to operate a once-through system and not generally by considerations of the thermal effects of the cooling water discharge. A few plants have installed cooling devices on their effluents to meet receiving water quality standards and a few others have installed or are planning to install cooling devices or to convert to closed systems in order to meet receiving water temperature requirements.

Generating of Electricity

The actual generation of electric energy is accomplished in a generator, usually directly connected to the turbine. The generator consists of a rotating element called a rotor revolving in a stationary frame called a stator. The process converts mechanical energy into electric energy at almost 100% of theoretical efficiency and therefore produces little waste heat.

Raw Materials

General aspects of the four basic fuels in use in the industry have been discussed in the previous section. In this section some of the characteristics of each of the fuels will be discussed as they affect the process and the wastewater effluents produced.

Coal

Coals are ranked according to their geological age which determines their fuel value and other characteristics. The oldest coals are the anthracites, which contain in excess of 92% fixed carbon. Most anthracite lies in a limited region of eastern Pennsylvania and is not a major factor in the nationwide generation of electric energy. Most of the power is produced from bituminous coal (the next lower rank) which contains between 50 and 92% fixed carbon and varies in fuel value between 19,300 and 32,600 J/g (8,300 and 14,000 Btu per lb). A substantial amount of power is also produced from lignite containing less than 50% carbon and having an average heating value of 15,600 J/g (6,700 Btu per lb).

Three major characteristics of coal that affect its use in powerplants are the percentages of volatile combustible matter, sulfur and ash. The sulfur content of coal is particularly critical since air pollution limitations restrict the emission of sulfur dioxide. The sulfur content of U. S. coals varies from 0.2 to 7.0 percent by weight.

Most of the low sulfur coal deposits are located west of the Mississippi River. In the East, a large portion of the low sulfur coal has been dedicated to metallurgical and export uses.

The ash content of coal varies from 5 to 20% by weight. Ash can create problems of air pollution, slagging, abrasion and generally reduced efficiency. One problem of substituting low sulfur coal for coal with a higher sulfur content is that low sulfur coals tend to have higher ash fusion temperatures, which may cause problems in boiler operation. The fly ash produced by low sulfur coal tends to have higher electrical resistivity which reduces the efficiency of electrostatic precipitators.

Several other aspects of coal as a fuel for steam electric powerplants should be noted. The first is the increased popularity of mine-mouth plants, that is plants built for the purpose of using coal from a specific mine and located in the immediate vicinity of that mine. Much of the current construction of coal-fired units consists of mine-mouth plants. These plants in effect trade off the cost of transporting coal against the cost of transmitting the electrical energy generated. Their major advantages are that in most cases that they are not located in or near urban centers and therefore do not arouse public opposition or have the same type of environmental impact as plants located within those centers. Most mine-mouth plants are base-load operated and many use cooling towers because of the absence of adequate cooling water supplies. They compete favorably on a unit cost basis with nuclear plants and in many instances can be constructed with a substantially shorter lead time.

A second aspect consists of the potential impact on the industry of the successful development of a commercial-scale coal gasification process. A number of processes are currently under development. The potential of coal gasification lies in its ability to produce a storable product that can be transported economically by pipeline and can be burned without ash or sulfur problems. At the present, the estimated cost of synthetic gas is still substantially higher than the cost of alternate fuels, but upward pressures on natural gas and residual oil prices may make coal gasification economically attractive.

Natural Gas

The use of natural gas as a fuel for generating electricity is a fairly recent development, dating back to about 1930. In 1970 0.1 trillion cu m (3.9 trillion cu ft) of natural gas were burned to generate electricity, placing natural gas second among the fossil fuels and accounting for almost 30% of the energy generated from fossil fuels.

The original attractions of natural gas were its availability and its economics. For a long time natural gas was considered almost a by-product. At the same time, its use in utility powerplants resulted in simpler and less costly fuel handling, burning facilities and a marked reduction in ash handling and air pollution problems. However, the availability of natural gas has declined sharply in the last few years, and utilities are finding it increasingly difficult to conclude long-term agreements for natural gas supplied for central generating plants. The future availability of natural gas is uncertain. Present reserves of natural gas amount to an estimated twelve times our current annual production, and the annual discovery of new sources is less than the current rate of consumption.

Estimates by the FPC project a fairly stable level of natural gas consumption by the electric utility industry over the next twenty years. However, in view of the projected growth of the industry as a whole, the share of the total electricity generated is expected to decrease to 8% by 1990. This trend could be affected by several technological developments. One of these is the successful commercial application of coal gasification. Another is an AEC program to increase the yield of natural gas from underground formations by the underground explosion of nuclear devices. In the meantime, some existing plants using natural gas as a fuel were being converted to oil in spite of the advantages of natural gas in the ash and air pollution areas.

Fuel Oil

Fuel oil is presently the third most significant source of fossil fuel for generating electricity, accounting for 15% of the total generation in 1970. However, in the New England- Middle Atlantic area it accounted for 82% of the thermal generation, primarily as a result of the conversion of coal-burning plants to residual fuel oil in order to meet air pollution standards.

Three types of fuel oil are used in utility powerplants: crude oil, distillate oil, and residual oil. A key problem with the use of fuel oil, as with the use of coal, is the sulfur content. At the present time, powerplants in the Northeast are burning oil containing less than 1% sulfur by weight. Domestic supplies of low sulfur crudes are quite limited and will not be improved significantly when Alaskan oil is available in the contiguous United States. As a result, utilities have been highly dependent on foreign sources of supply. Major foreign sources include Venezuela, and the Middle East. Venezuelan sources must be, and are, desulfurized at the source, while Middle Eastern crudes are low in sulfur in their original state.

With the future availability of petroleum products of all types in question, it appears doubtful that the recent trend toward increased burning of oil in powerplants will continue in the future. FPC projections (1970) indicated a slight increase in the percentage share of oil compared to total use of fossil fuels over the next five years, with a leveling off thereafter. The price of fuel oil, which had remained fairly constant during the early 1960's has increased in recent years, and will possibly increase further in the future.

A possible technological development which might affect the supply of fuel oil is the extraction of oil from oil shales. Certain areas of Colorado, Utah and Wyoming contain large reserves of oil shale, with unfavorable economics being the major obstruction to the development of an oil shale industry. If crude oil prices continue to escalate and oil supplies continue to dwindle, the development of this source may become economically viable.

Fuel oil use in powerplants minimizes bottom ash problems, although fly ash can continue to be troublesome. Some fuel oils also contain vanadium and may contain other unusual components which may or may not wind up in a powerplant effluent.

Refuse

Emphasis on recycling waste products has increased interest in use of another fuel - solid waste. Refuse and garbage are not confined to kitchen wastes, but include a mixture of all household wastes with commercial and industrial wastes. Large-scale inorganic industrial wastes are generally not included. The average American domestic refuse has many combustibles which raise its heating value to approximately 40% of that of coal. Incineration coupled with steam generation has been practiced for a considerable period in Europe, where household garbage as collected is mixed, especially during the winter months, with the ashes of household coal furnaces. Garbage is generally shredded and most non-combustibles are removed by magnetic and centrifugal separators before firing to the furnace.

However, furnaces must still be designed for non-combustible loadings. Garbage is essentially sulfur-free but can generate moderate quantities of hydrogen chloride from the combustion of polyvinyl chloride and other chlorinated polymers. Because of the presence of these materials, studies of the removal of acid gases from the furnace stack gases, and the disposal of the effluents resulting from these operations should continue.

At the present time there is one powerplant in the United States that burns refuse as part of its fuel. The plant has the capability of using as much as 20% refuse with at least 80% coal, although operation to date has been limited to 10% refuse and 90% coal.

Information on U.S. Generating Facilities (Size and Age)

An inventory of operating steam electric powerplants in the United States is presented in Appendix 1 of this report. The list has been divided into ten sections to conform to the ten EPA regions of the country. The inventory shows the operating utilities by states, plants, and their specific geographic location. It also shows the total plant capacity in megawatts, with an indication of whether the plant is nuclear or fossil-fueled, and a designation of plants that are under construction. Gas combustion turbine facilities operating within fossil-fueled generating plants have been indicated on a separate line.

The inventory shows a total of 1,037 operating generating plants in the United States as of January 1, 1972, consisting of 1011 fossil-fired plants and 26 nuclear plants. A total of 59 plants were under construction as of the date indicated. Of this total, 42 are nuclear plants and 17 are fossil-fueled plants. Table IV-1 provides a summary of the industry inventory by EPA region and individual states.

Figures IV-6 through IV-8 provide a cumulative frequency distribution plot of plant size within the steam electric powerplant industry. It can be seen from Figure IV-6 that approximately 50 percent of the plants in the industry are 100 Mw or larger, and that 25 percent of all plants are larger than 400 Mw. Figure IV-7 shows that the size distribution of fossil-fueled plants roughly corresponds to the industry profile. However, Figure IV-8 illustrates the large size of nuclear plants, showing that 50 percent of these plants are larger than 800 Mw, and that 25 percent are larger than 1,500 Mw.

TABLE IV-1
INDUSTRY INVENTORY SUMMARY

STATE	OPERATING PLANTS TOTAL	OPERATING PLANTS FOSSIL	OPERATING PLANTS NUCLEAR	PLANTS UNDER CONSTRUCTION FOSSIL	PLANTS UNDER CONSTRUCTION NUCLEAR
EPA Region 1					
Connecticut	16	13	3	0	0
New Hampshire	5	5	0	0	0
Rhode Island	5	5	0	0	0
Vermont	4	3	1	0	0
Maine	6	6	0	0	1
Massachusetts	29	28	1	0	1
EPA Region 2					
New Jersey	18	17	1	0	1
New York	39	36	3	1	2
Puerto Rico	4	4	0	0	0
Virgin Islands	2	2	0	0	0
EPA Region 3					
Delaware	5	5	0	0	0
Maryland	14	14	0	0	1
Pennsylvania	48	45	3	0	2
Virginia	15	15	0	0	2
West Virginia	12	12	0	1	0
District of Columbia	2	2	0	0	0
EPA Region 4					
Alabama	10	10	0	0	3
Florida	43	43	0	0	4
Georgia	13	13	0	3	1
Kentucky	19	19	0	2	0
Mississippi	9	9	0	0	0
North Carolina	12	12	0	1	2
South Carolina	16	15	1	1	1
Tennessee	7	7	0	1	1
EPA Region 5					
Illinois	45	43	2	1	3
Indiana	29	29	0	1	0
Michigan	40	38	2	2	4
Minnesota	48	45	3	0	1
Ohio	54	54	0	0	3
Wisconsin	33	31	2	0	1
EPA Region 6					
Arkansas	10	10	0	0	1
Louisiana	27	27	0	1	1
New Mexico	16	16	0	0	0
Texas	91	91	0	1	0
Oklahoma	19	19	0	0	0
EPA Region 7					
Iowa	37	37	0	0	1
Kansas	32	32	0	0	0
Missouri	31	31	0	0	0
Nebraska	15	15	0	0	2
EPA Region 8					
Colorado	23	23	0	0	1
Montana	8	8	0	0	0
North Dakota	9	9	0	0	0
South Dakota	9	8	1	0	0
Utah	6	6	0	0	0
Wyoming	8	8	0	0	0
EPA Region 9					
Arizona	12	12	0	1	0
California	39	37	2	0	2
Hawaii	7	7	0	0	0
Nevada	6	6	0	0	0
EPA Region 10					
Alaska	14	13	1	0	0
Idaho	1	1	0	0	0
Oregon	6	6	0	0	0
Washington	9	9	0	0	0
TOTAL	1037	1011	26	17	42

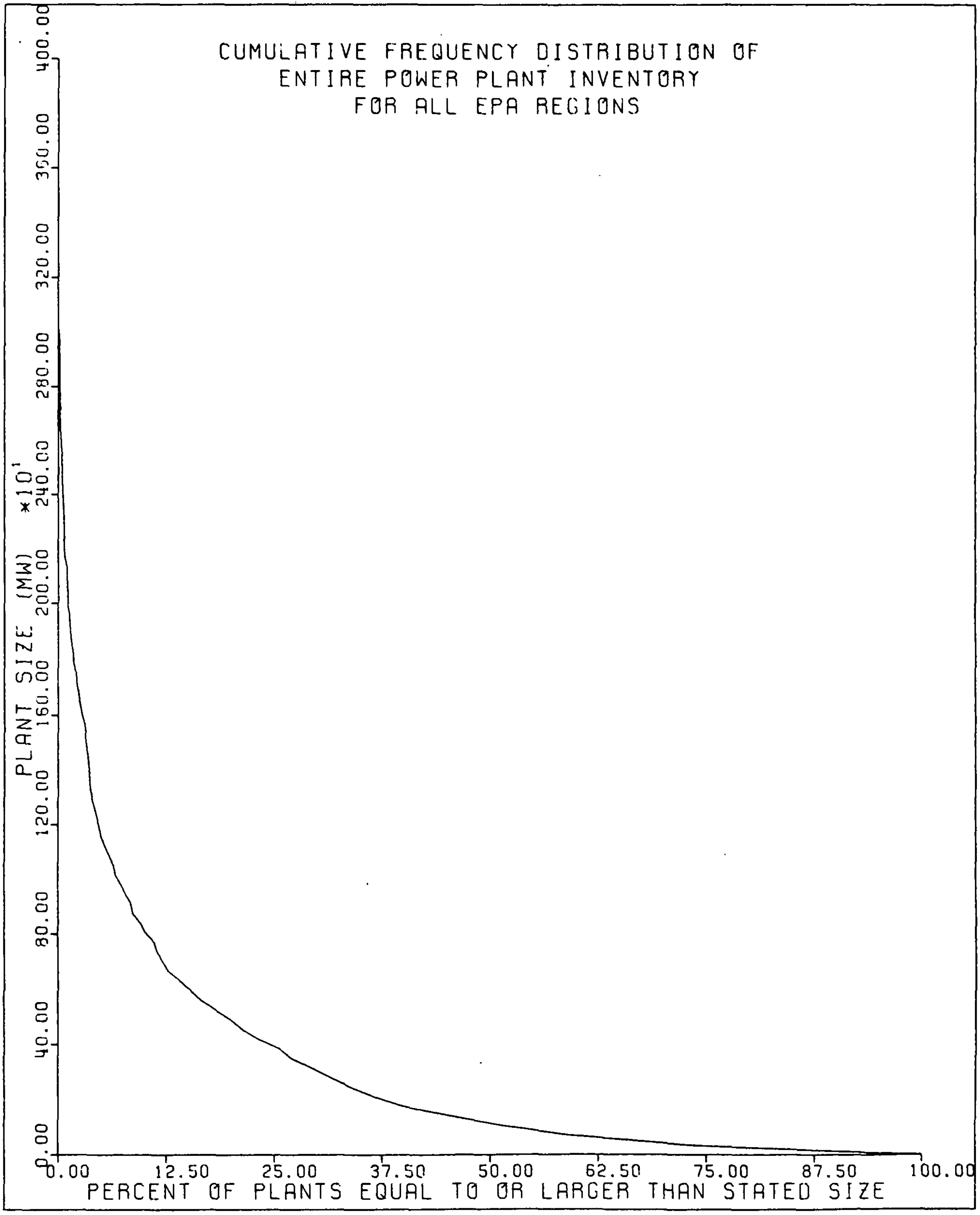

CUMULATIVE FREQUENCY DISTRIBUTION OF
ENTIRE POWER PLANT INVENTORY
FOR ALL EPA REGIONS
PLANT SIZE (MW) *10¹
0.00
40.00
80.00
120.00
160.00
200.00
240.00
280.00
320.00
360.00
400.00
0.00
12.50
25.00
37.50
50.00
62.50
75.00
87.50
100.00
PERCENT OF PLANTS EQUAL TO OR LARGER THAN STATED SIZE

FIGURE IV-6

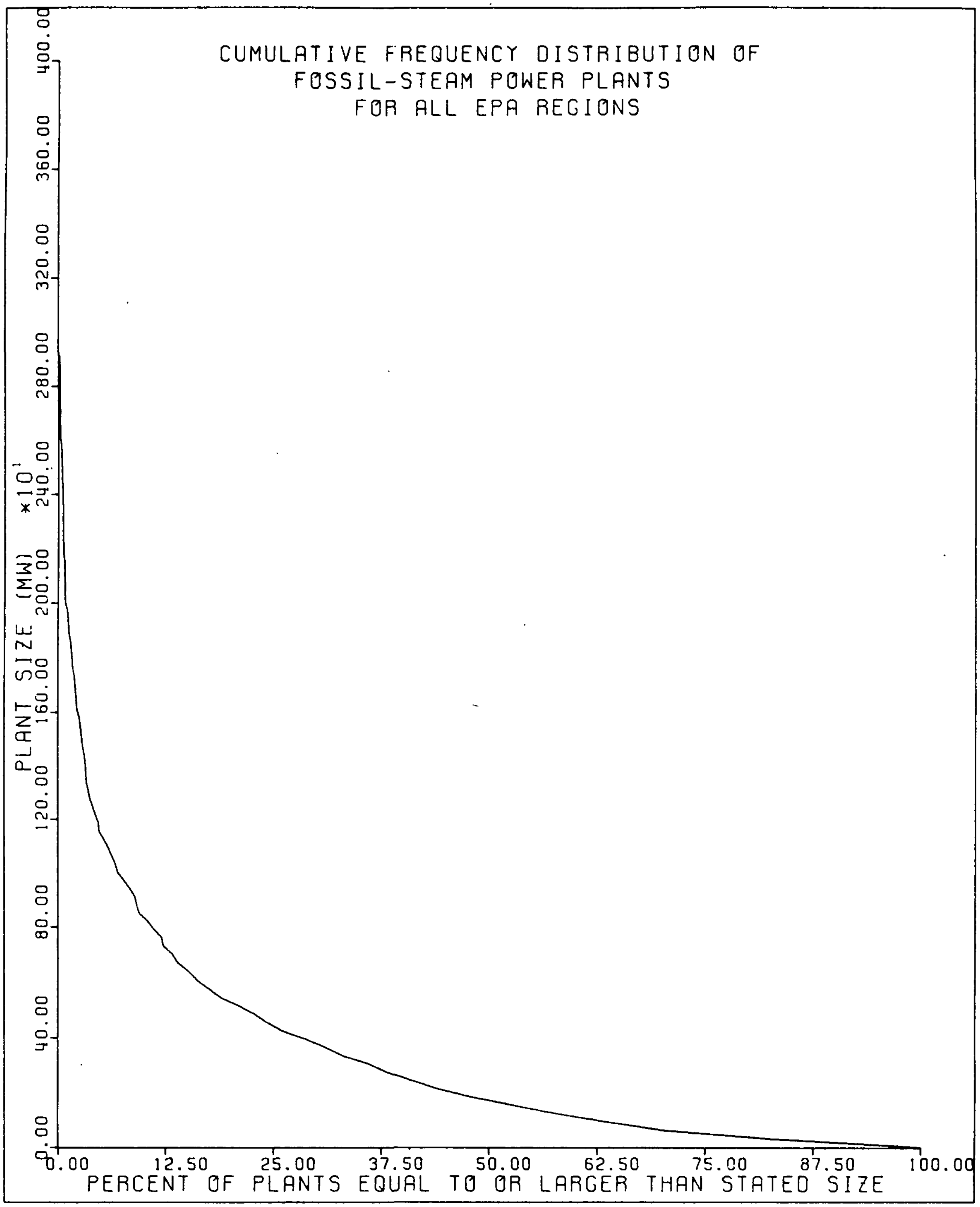

CUMULATIVE FREQUENCY DISTRIBUTION OF
FOSSIL-STEAM POWER PLANTS
FOR ALL EPA REGIONS
PLANT SIZE (MW) *10¹
0.00
40.00
80.00
120.00
160.00
200.00
240.00
280.00
320.00
360.00
400.00
0.00
12.50
25.00
37.50
50.00
62.50
75.00
87.50
100.00
PERCENT OF PLANTS EQUAL TO OR LARGER THAN STATED SIZE

FIGURE IV- 7

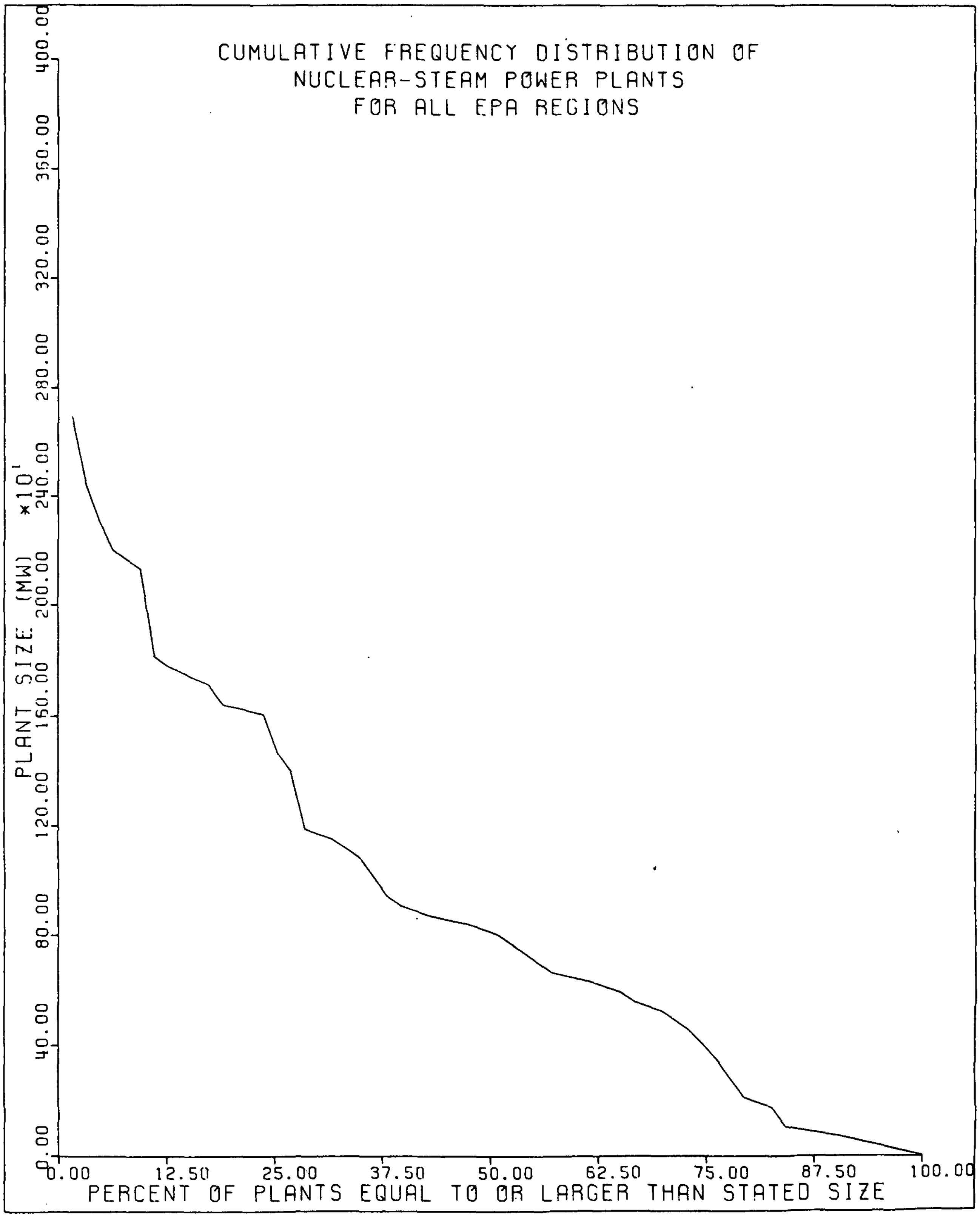

CUMULATIVE FREQUENCY DISTRIBUTION OF
NUCLEAR-STEAM POWER PLANTS
FOR ALL EPA REGIONS
PLANT SIZE (MW) $\times 10^1$
0.00
40.00
80.00
120.00
160.00
200.00
240.00
280.00
320.00
360.00
400.00
0.00
12.50
25.00
37.50
50.00
62.50
75.00
87.50
100.00
PERCENT OF PLANTS EQUAL TO OR LARGER THAN STATED SIZE

FIGURE IV- 8

The Federal Power Commission Form 67, "Steam-Electric Plant Air and Water Quality Control Data for the Year Ended December 31, 1969" provides data on the capacity utilization, age, etc., of generating units. This form must be filed annually by plants with a generating capacity of 25 Mw or greater, provided the plant is part of a system with a total capacity of 150 Mw or more.

Size of Units

According to the Federal Power Commission (FPC) 1970 National Power Survey, in 1930, the largest steam-electric unit in the United States was about 200 megawatts, and the average size of all units was 20 megawatts. Over 95 percent of all units in operation at that time had capacities of 50 megawatts or less. By 1955, when the swing to larger units began to be significant, the largest unit size had increased to about 300 megawatts, and the average size had increased to 35 megawatts, (see Figure IV-9). There were then 31 units of 200 megawatts or larger. By 1968, the largest unit in operation was 1,000 megawatts; there were 65 units in the 400 to 1,000 megawatt range; and the average size for all operating units had increased to 66 megawatts. In 1970, the largest unit in service was 1,150 megawatts; three 1,300-megawatt units were under construction; and three additional 1,300-megawatt units were on order. The average size of all units under construction was about 450 megawatts. As the smaller and older units are retired, the average size of units is expected to increase to about 160 megawatts by 1980 and 370 megawatts by 1990.

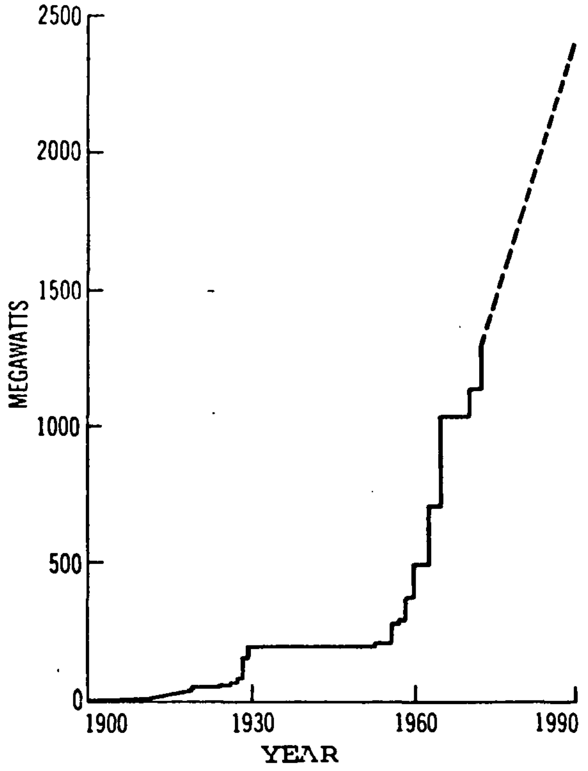
The distribution of U.S. generating capacity by size, as a percentage of the generating capacity installed in particular years, is given in Table IV-2.

Age of Facilities

In the steam electric powerplant industry, age of generating facilities must be discussed on the basis of units rather than on a plant basis. Generally, the units comprising a generating plant have been installed at different times over a period of years, so that the age of equipment within a given plant is likely to be distributed over a range of years. In addition, age may play a peculiar role in assigning a unit to a particular type of operation as outlined below.

In general, the thermal efficiency of newly designed power generation plants has increased as operating experience and design technology have progressed. Early plants generated

Figure IV- 9



LARGEST FOSSIL - FUELED STEAM-ELECTRIC TURBINE-GENERATORS IN SERVICE 292

1900 - 1990

Table IV-2

DISTRIBUTION OF INSTALLED GENERATING CAPACITY IN THE U.S. BY SIZE FOR VARIOUS YEARS WHEN EQUIPMENT WAS FIRST PLACED IN SERVICE

Generating Capacity, megawatts	Year in Which Equipment was First Placed in Service							
	1945	1955	1960	1965	1970	1972	1974	1970-1974
0 - 24	18	8	4	0	1	0	0	0
25 - 99	58	26	13	12	4	1	3	1
100 - 299	24	66	56	55	32	13	3	13
300 - 499	0	0	27	25	32	13	10	15
500 -	0	0	0	8	31	73	84	71

saturated steam at low pressures and consumed large quantities of fuel to produce a unit of electrical energy. One electrical kilowatt hour of energy is equivalent to 860 k cal (3,413 Btu) of heat energy. Steam pressures and temperatures increased from about 1.17 MN/sq m (170 psig) at the turn of the century to 1.72 - 1.90 MN/sq m (250 - 275 psig) and 293°C (560°F) by World War I, and to 3.10 - 4.48 MN/sq m (450-640 psig) and 370-400°C (700-750°F) by 1924.[278] In 1924 and 1925 there was a surge to 8.27 MN/sq m (1,200 psig) and 370°C (700°F) and it has steadily increased since then, until by 1953 pressures had reached the critical pressure of steam (22.11 MN/sq m (3,206 psia) and temperatures of 540-565°C (1,000-1,050°F).[278] Above the critical pressure the liquid and vapor phases are indistinguishable and there is no need for a steam drum (separator). The economic justification of the supercritical cycle has resulted in a limited number of this type of unit to date.

These changes have had the effect of reducing the amount of fuel required to generate a kilowatt hour, as shown in Figure IV-10, taken from Reference No. 292. In 1900 it required 2.72 kg (6 pounds) of coal, (41,700 k cal (75,000 Btu) to generate one kwh. Today a supercritical, double-reheat unit of Plant no. 3927 has established an annual heat rate of 2197 k cal/kwh (8,717 Btu/kwh).[280] This amounts to 0.318 kg (seven-tenths of a pound) of coal per kwh. The heat economies of the newer facilities generally make it desirable to keep them in full-time base-load operation. The older units with their higher fuel consumption are therefore generally relegated to cycling or peaking service. In spite of this general trend, there are indications that heat rates have been increasing since 1972 as a result of pressures to reduce capital cost in relation to fuel prices, and increasing use of air and water pollution control equipment which tend to reduce generating efficiency.

A computer plot of heat rate in Btu/kwh vs unit capacity in megawatts (x 10) is shown in Figure IV-11. The plot is a print-out of data obtained from FPC Form 67 for the year 1969. In the plot, data obtained from newer plants (under 10 years old) are represented by squares, those 10-20 years old by triangles, and those over 20 years by X's. Similarly, Figure IV-12 is a printout of the same information replotted with Btu/kwh as the ordinate and unit age as the abscissa. The data from both plots represent over 1,000 operating units, and are not conclusive, but do show general trends. The newer plants, of larger size, generally are more efficient. Thus the data illustrates the

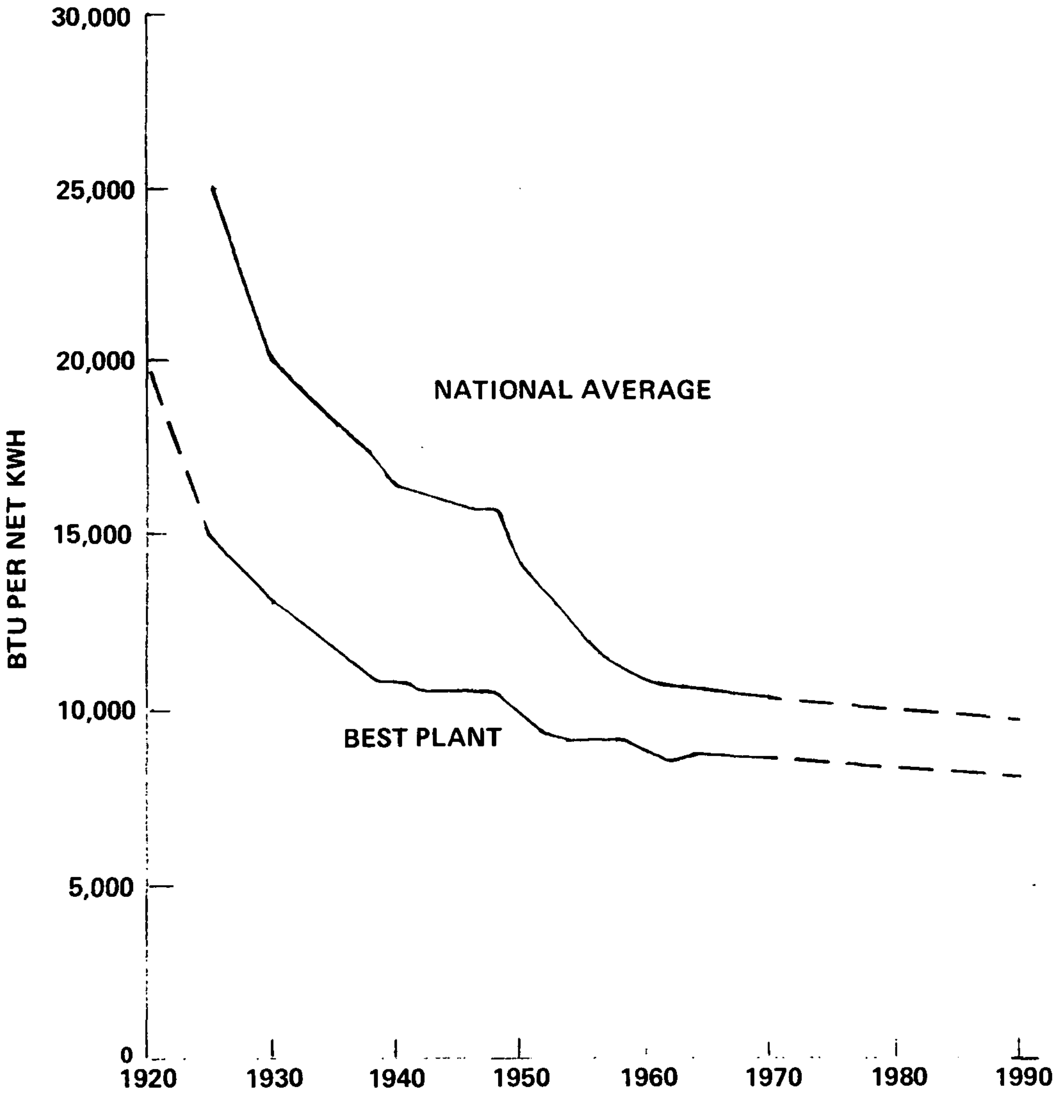


FIGURE IV-10HEAT RATES OF FOSSIL-FUELED STEAM ELECTRIC PLANTS

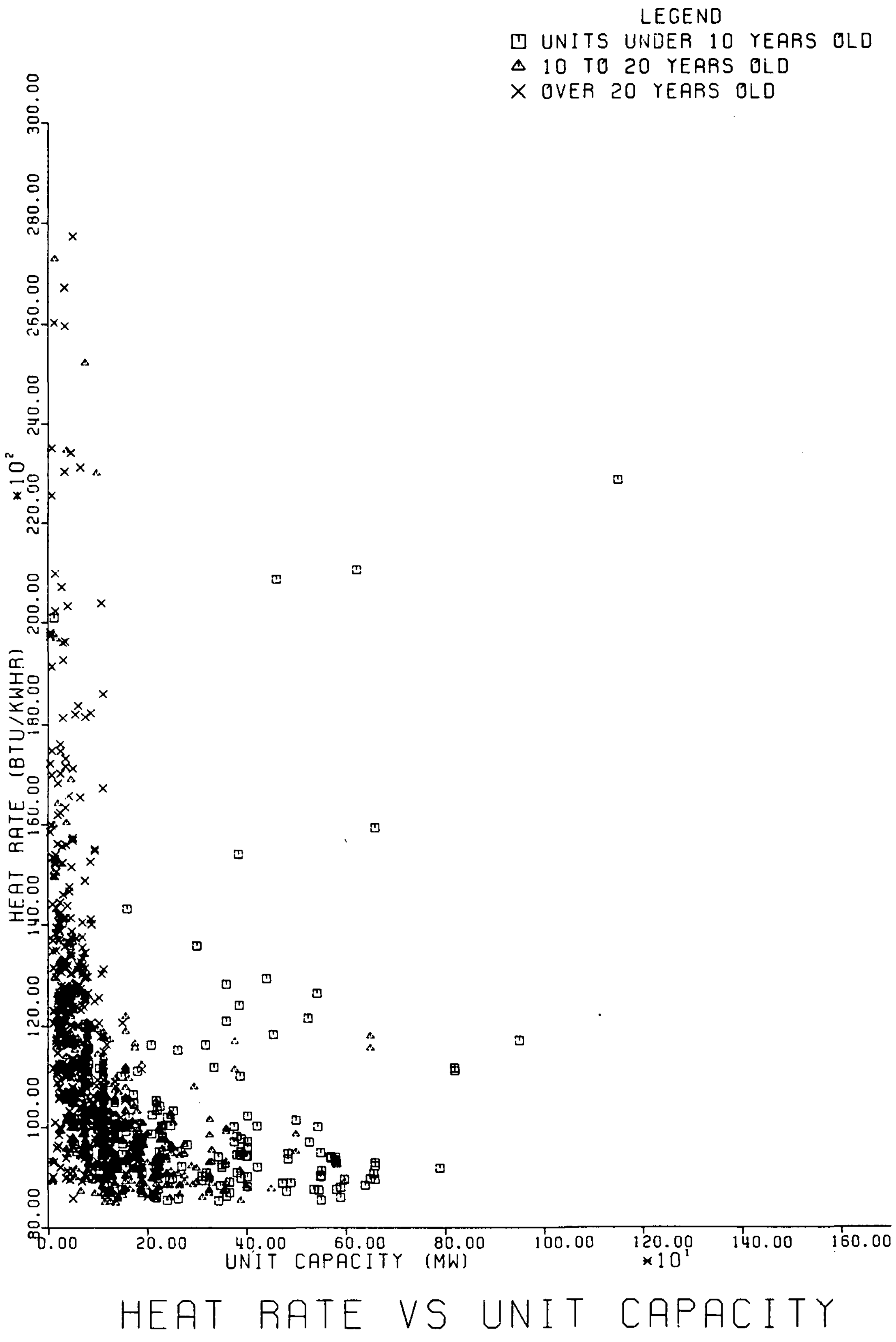
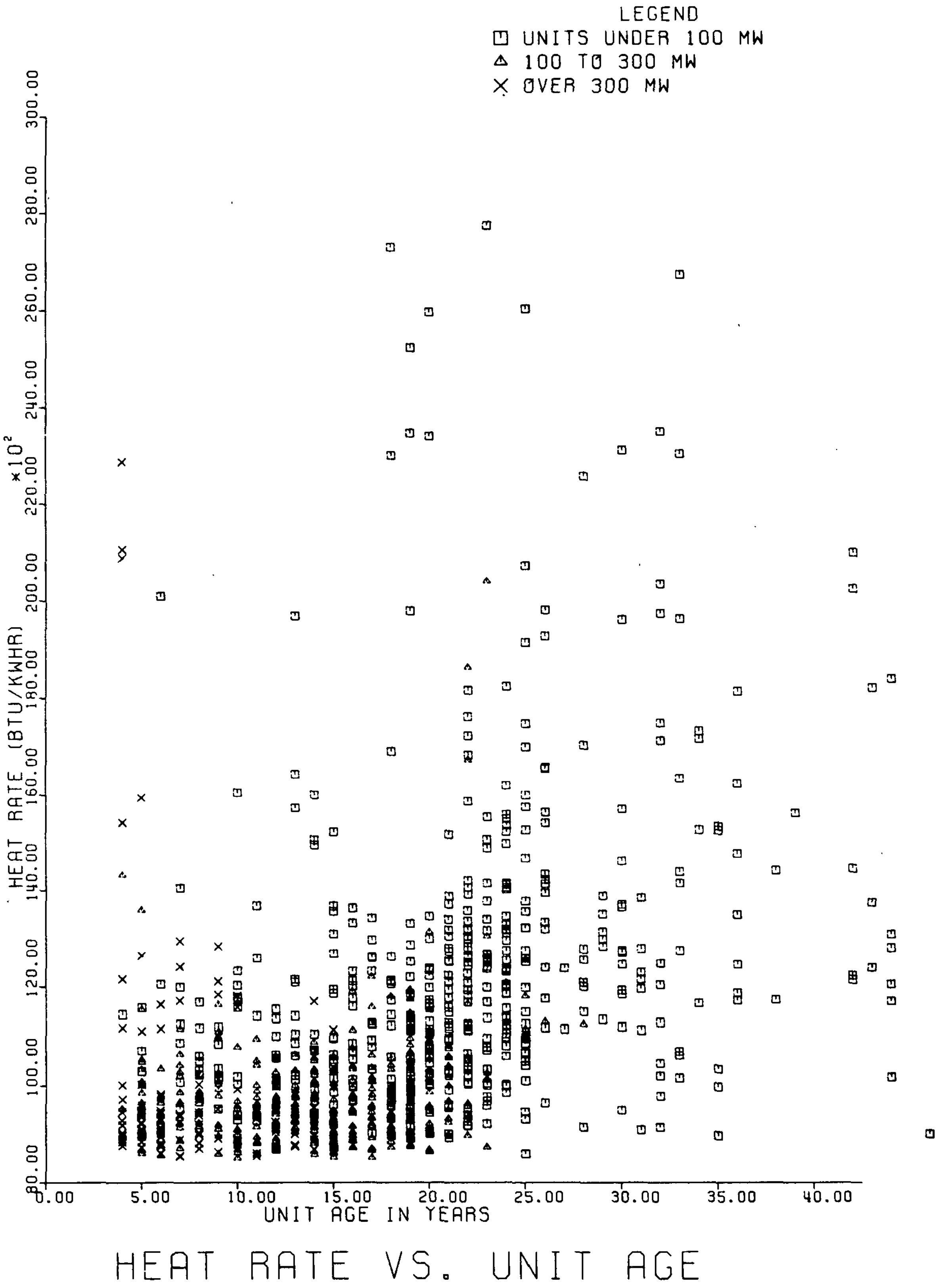

LEGEND
□ UNITS UNDER 10 YEARS OLD
△ 10 TO 20 YEARS OLD
× OVER 20 YEARS OLD
HEAT RATE (BTU/KWHR)
×10²
80.00
100.00
120.00
140.00
160.00
180.00
200.00
220.00
240.00
260.00
280.00
300.00
0.00
20.00
40.00
60.00
80.00
100.00
120.00
140.00
160.00
UNIT CAPACITY (MW)
×10¹
HEAT RATE VS UNIT CAPACITY

Figure IV-1



LEGEND
□ UNITS UNDER 100 MW
△ 100 TO 300 MW
✕ OVER 300 MW
HEAT RATE (BTU/KWHR) ×10²
80.00
100.00
120.00
140.00
160.00
180.00
200.00
220.00
240.00
260.00
280.00
300.00
UNIT AGE IN YEARS
0.00
5.00
10.00
15.00
20.00
25.00
30.00
35.00
40.00
HEAT RATE VS. UNIT AGE

Figure IV-12

improvement in efficiency achieved as the industry has progressed to newer and larger generating facilities.

Mode of Operation (Utilization)

The need for considering a subcategorization of the industry based on utilization arises because of the costs and economics associated with the installation of supplemental cooling facilities. The unit cost increment (mills/kwh) required to amortize the capital costs of the cooling system is dependent on the remaining kwh's that individual units will generate. The remaining generation is a function of both the manner in which the individual unit is utilized and the number of years that the unit will operate prior to retirement. These two factors are not fully independent variables. In general, utilities will employ their most efficient, usually newest equipment most intensively. This equipment will also generally have the longest remaining useful life. The cost of installing supplemental cooling water equipment for these units relative to the remaining generation will therefore be relatively low. Therefore, these more modern, highly-utilized units, which also would reject relatively large amounts of the waste heat, are better able to carry the costs associated with thermal effluent control.

Less efficient, usually older equipment will be utilized to a lesser degree to meet daily and seasonal peak loads. This lower annual utilization is compounded by the fact that this equipment has relatively fewer remaining years of service prior to retirement. Therefore, the cost of amortizing supplemental cooling equipment for these units will be substantially higher than for the newer, more highly utilized units. Because of their low utilization, these units will reject considerably less heat per unit of capacity than the newer equipment. Also, because of the higher costs associated with this equipment, utilities might consider early retirement of much of this equipment rather than the installion of costly treatment equipment. Since these units provide an important function as peaking or standby capacity, retirement prior to the installation of replacement capacity would have associated penalties.

According to the FPC National Power Survey (1970), all of the high-pressure, high-temperature, fossil-fueled steam-electric generating units, 500 megawatts and larger, have been designed as "base load" units and built for continuous operation at or near full load. Daily or frequent "stops" and "starts" are not consistent with their design and construction and so-called "cycling" or part-time variable generation was not originally comtemplated for these units. However, by the time units having lower incremental production costs become available for base load operation, it is believed that the earlier "base load" units can be adapted and used as "intermediate" peaking units. The units placed in service during the 1960's still have 15 or more years of base load service ahead of them, but eventually the installation of more economical base load equipment may make it desirable to convert to peaking service those units which are suitable for such conversion.

New steam-electric peaking units, sometimes referred to as mid-range peaking units, are designed for minimum capital cost and to operate at low capacity factor. They are oil- or gas-fired, with a minimum of duplicate auxiliaries, and operate at relatively low pressures, temperatures, and efficiencies. They are capable of quick startups and stops and variable loading, without jeopardizing the integrity of the facilities. Such units are economical because low capital costs and low annual fixed charges offset low efficiency and operation at low capacity factors. The units can, however, be operated for extended periods, if needed, to meet emergency situations.

The first of such fossil-fueled steam-electric units designed for peaking service, a 100-megawatt, 1,450 psi, 1000°F, non-reheat, gas-fired unit, was installed in 1960. Two earlier low capital cost fossil-fueled steam-electric plants--a 69-megawatt, single-unit plant (1952), and a 313-megawatt, two-unit plant (1954)--were generally classified as hydro standby; they were not straight peaking installations. The 313-megawatt plant was later modified for base load operation.

With increasing loads and the accompanying need for additional peaking capacity, at least 27 peaking units of this general type were on order or under construction at the end of 1970. All are either oil- or gas-fired, because the added costs of coal and ash handling facilities for peaking units are not justified by the small fuel cost saving that might be realized by using coal. Eight of the 27 units are in the 250 to 350-megawatt class, fifteen in the 400-megawatt class, and four in the 600-megawatt class. Most of the units are designed for steam conditions of 1,800 psi and 950°/950°F.

The use of the nuclear power plant in conjunction with other forms of generation in order to provide energy to meet the daily requirements of a power system will probably not be vastly different from the use of a fossil-fueled plant of the same capacity. There are some differences, however, that may affect the operation of the nuclear plant, such as relative operating costs, refueling time and inspections.

Because an economic loading schedule for a power system will tend to favor operation of units with the lowest incremental production cost, the capacity factor of a nuclear fueled plant is expected to be relatively high when it is added to a system consisting of fossil-fueled plants. However, when newer, more efficient nuclear plants are added to the system, which can operate with even lower production costs, the first nuclear plants will begin to have decreasing capacity factors. Most of the plants that have been ordered during the past three years will probably have annual capacity factors of 80 percent or better for a period of ten to fifteen years, depending on the operating requirements and makeup of the system.

The limited operating experience to date with the comparatively small nuclear plants indicates that they are able to handle load swings without difficulty. It is expected that the larger units now on order will perform similarly, but it may develop that they will not be amenable to load regulation. In that event, fossil units, pumped-storage units, conventional hydro units, or other types of peaking units will be installed to carry peak load with nuclear units being maintained at base load for substantially all of their useful lives. If nuclear units are to be utilized with very low annual capacity factors, substantial research and engineering effort must go into the determination of core designs to economically accomplish this type of operation.

Base-load units are responsible for the bulk of the thermal discharges, will continue to operate for many more years, and are able to support the required technology with relatively small increases in the bus-bar cost of power. The balance of the steam-electric power generation inventory is made up of older equipment, which reject considerably less heat and for which the cost of installing control and treatment technology would be considerably higher relative to the effluent reduction benefits obtained. It is understood that considerable abatement will take place in time in this older portion of the inventory due to normal attrition.

Traditionally, the power industry has employed two categories for generating equipment. Units that are continuously connected to load, with the exception of scheduled and unscheduled maintenance periods, have been termed base-loaded units. Units which are operated to meet seasonal peak loads have been termed peaking units. Daily load swings have usually been met by modulation of the base-loaded units. More recently, the increased cycle sophistication built into the newer base-loaded equipment has made them less efficient in accommodating large daily load swings. Therefore, a third type of capacity called cyclic or intermediate generation unit has come into general acceptance within the industry. This third type of unit is usually a downgraded base-loaded unit which can be adapted to the intermittent operation with fairly rapid load swings.

The progression of individual units of capacity through the three types of duty assignments generally follows the sequence given below:

1. New steam electric capacity has historically been added as base-load units. All but a few existing steam electric generating units were at one time base-loaded units. Beginning in the middle 1960's some new peaking units, both steam electric and gas turbine types have been constructed. More recently (late 1960's early 1970's) several units of the combined (gas turbine/steam turbine) cycle design have been designed specifically for cyclic or intermittent duty. The aggregate existing capacity of units originally built for peaking or cyclic service is considerably less than 1% of the total steam electric inventory.

2. Cycling capacity and peaking capacity has been obtained by downgrading the older less efficient base-loaded equipment as more efficient replacement capacity has been built. The manner in which a unit is downgraded depends upon the needs of the individual utility and the requirements of its system load curve. Toward the end of its useful life, the unit may be held in standby duty to be used only in the event of an outage to the other units.

3. Units have been retired from the bottom level of utilization. Therefore, retirements of steam electric capacity have generally been made from the peaking inventory. While the annual retirement of steam electric powerplant capacity have been significantly less than 1% of the total capacity, this amount constitutes a significant portion of the present peaking inventory.

The typical utility makes duty assignments by comparing the capability of its available generating units against the requirements of its system load curve. Efficient system operation dictates that the most efficient equipment be operated continuously. These are the base-loaded units. In descending order, the less efficient equipment is assigned lower utilization duty to meet daily and seasonal variations in the load curve. The process of matching capacity to load is different for each utility. The system load curve will be different for each utility as will the capability of its individual generating units.

Large systems will have sufficient diversity of load which will dampen extreme peaks and valleys in the characteristic load curve. They will also have multiple units serving each of the load segments and considerable flexibility in making duty assignments. Individual large industrial loads may dominate the system load curve for smaller utilities and highs and lows of load may be more exaggerated. Duty assignments for smaller systems will be more constrained by the lack of multiple units and single units may be found which service all three load segments. Duty assignments are also influenced by the needs of the regional power grid in which most utilities participate through a series of agreements governing interconnections.

The diversity in both load and available capacity complicates the process of establishing concrete limits between the three types of generating equipment. The following bases of establishing definiticns of base-load, cyclic and peaking units have been considered.

1. Qualitative descriptions of the three types of operation.

2. Annual hours of operation.

3. Plant index numbers such as load factor, capacity factor, utilization factor, etc.

The relative merits of definitions based on these systems are discussed below. The ideal definition should be relatively easy to employ, allow effective separation of the three types of generation, and be understood and accepted.

Definitions Based on Qualitative Description of the Three Types of Generation

This would rely on a description of the three types of generation as the basis of separation. Suggested definitions of the three types of generation are as follows:

A base-loaded unit is one which is continuously connected to load except for periods of scheduled or unscheduled maintenance.

A cycling unit is one which services daily load variations above the base-load. This type of unit is typically connected to load some 250 days per year for a typical period of about 12 hours. When not connected to load the boiler is kept warm to allow rapid return to the system.

A peaking unit is one which is operated to meet peak loads only. During periods when the unit is not generating power it is held in standby or is shut down.

Annual Hours of Operation

It is clear that a basic difference between the three types of generation is the amount of time that the different units operate.

Reference 292, Part II suggests that steam peaking units are designed to operate less than 2,000 hours per year. Reference 256 indicates that base-load units operate in excess of 6,000 hours per year. Units which operate between these two limits would be defined as cycling units. The hours of operation referred to in this system are hours that the unit is connected to load. Hours of boiler operation are not satisfactory. There is considerable difference in hours of boiler operation and hours connected to load for cycling and peaking units. Hours of condenser operation could be used as a substitute since it is equivalent to hours connected to load. See Table IV-3 for the heat rate, service life, and capacity factors characteristic of units within the above groupings based on hours of operation.

Historical records of annual hours of operation are required to employ this sytem. There will be instances where base-loaded units will have been operated less than 6,000 hours per year because of extended maintenance requirements. On the other hand there will be cases of stretching out the operating schedules of peaking and cycling units because of capacity shortage in particular systems. This system does have the advantage of a basic simplicity in discriminating between the different categories of generation.

Performance Indices

This would require relating the utilization of a unit to indices of its performance. Several of these indices are described below.

Table IV-3

CHARACTERISTICS OF UNITS BASED ON ANNUAL HOURS OF OPERATION

Annual Hours of Operation	Heat Rate, Btu/kwhr			Remaining Service* yr			Capacity Factor		
	Min.	Mean	Max.	Min.	Mean	Max.	Min.	Mean	Max.
0 - 2000	8727	15793	27315	1	11	26	.01	.07	.17
2000 - 6000	8735	12493	27748	1	15	26	.03	.35	.71
6000 - 8760	8706	10636	26741	1	19	32	.15	.67	1.12

* Note: Based on a total service life of 36 years.

Load Factor

Load factor is the ratio of the average demand for power (kilowatts) over a designated period to the maximum demand for power occurring in that period. The average demand is the total (kilowatt-hours) for the period divided by the total time span (hours). For example, in the twelve months ended December 31, 1971, the electric energy generated and purchased less sales to other electric utilities amounted to 35,720,253,101 kilowatt-hours. The one-hour net maximum demand was 7,719,000 kw. The average hourly demand was, consequently, 35,720,253,101 / 8760 = 4,078,000 kw. The annual system load factor is, therefore, 4,078,000 / 7,719,000 = 0.528 or 52.8%. The load factor may be regarded as providing some measure of the variation of demand during a given period. Thus, if the load factor is 100% over a period of 24 hours, the demand has been maintained constant for the duration of the period.

Operating Load Factor

If the maximum demand varies from day to day, then the operating load factor is the ratio of the average demand to the average value of the maximum demands for the period. For example, the daily maximum demands for a ten-day period and the corresponding kilowatt-hours are as follows:

Day		Maximum Demand kw	Kilowatt Hours Per day
1		1,000	19,200
2		950	13,700
3		800	14,400
4		980	9,700
5		700	10,900
6		850	18,000
7		500	7,000
8		750	10,000
9		820	9,100
10		900	12,000
	Totals	8,250	124,000

Maximum Demand 1,000 kw
Average Maximum Demand = 8,250 / 10 = 825 kw
Average Demand = 124,000 / (10 x 24) = 517 kw

Load Factor = (517 / 1000) x 100 = 51.7%
Operating Load Factor = (517 / 825) x 100 = 62.6%

Thus the operating load factor takes into account the variation of the daily maximum demand.

Capacity Factor

Capacity factor defines the relation between energy output over a given time span and the capacity for energy production over the same time span, and normally provides measure of the utilization of the generating equipment relative to investment. This factor is also a ratio of the average load to the total rating of the installed generating equipment for a given period. For example, in the twelve months ended December 31, 1970, one unit generated 4,465,175,600 kilowatt-hours (exclusive of gas turbine generation). The maximum unit capacity (winter rating) was 878,000 kw. The average hourly load was 4,465,175,600 / 8760 = 509,723 kw. The annual capacity factor is therefore, 509,723 / 878,000 = 0.5806 or 58.1%.

Operating Capacity Factor

Although a plant may have installed equipment of a certain amount of generating capacity, only part of this may be in actual operation for the given period. Suppose for a certain generating plant the capacity of the installed equipment is 770,000 kw and for some particular month only 600,000 kw of boiler capacity is actually operating. This means that the maximum demand that can be imposed on the plant is limited to 600,000 kw. The operating capacity factor for the month would then be in the ratio of the average demand for power to 600,000 kw, the maximum capacity utilized. This factor therefore, determines the relation between average output and the peak demand for power which the plant is prepared to meet.

Use Factor

This term is generally used in connection with the performance of turbo-generators. It is the ratio of the actual energy output of a machine during a certain period to the energy generation which could have been obtained during the actual operating hours in that period by operating the machine at rated capacity. A turbo-generator operating for 7,000 hours generated 350,000,000 kilowatt-hours. The rated capacity of the unit is 100,000 kw. The use factor was 350,000,000 / (100,000 x 7,000) = 0.5 or 50%.

Section 304(b) of the Act requires the Administrator to take into account, in determining the applicable control measures and practices, the total cost of application of technology in relation to the effluent reduction benefits to be achieved from such application. Among the above factors, the capacity factor alone would determine, for otherwise similar circumstances, the incremental production cost associated with the application of pollution control technology in relation to the effluent reduction benefits to be achieved.

The 1970 National Power Survey by the Federal Power Commission (FPC) describes base-load, intermediate, and peaking units as follows. Base-load units are designed to run more or less continuously near full capacity, except for periodic maintenance shutdowns. Peaking units are designed to supply electricity principally during times of maximum system demand and characteristically run only a few hours a day. Units used for intermediate service between the extremes of base-load and peaking service must be able to respond readily to swings in systems demand, or cycling. Units used for base-load service produce 60 percent, or more, of their intended maximum output during any given year, i.e., 60 percent, or more, capacity factor; peaking units less than 20 percent; and cycling units 20 to 60 percent. The FPC Form 67, which must be submitted annually by all steam electric plants (except small plants or plants in small systems) reports annual boiler capacity factors for each boiler. The boiler capacity factor is indicative of the gross generation of the associated generating unit.

Site Characteristics

Engineering criteria require an adequate supply of cooling water, adequacy of fuel supply, fuel delivery and handling facilities, and proximity of load centers. These have always been important factors in the selection of powerplant sites.[292] Traditionally, plants have been located in or near population centers to reduce transmission costs and satisfy the other key site factors mentioned. Table IV-4 shows a total of 153 plants located in the 50 largest cities of the country. This total represents approximately 15 percent of all plants in the industry, and does not include suburban plants near the cities in question, or urban plants in smaller population centers. Clearly, a significant number of existing plants in the steam electric generating industry are situated in locations which interface with a reasonable percentage of the country's population.

Table IV-4

URBAN STEAM ELECTRIC POWER PLANTS

NO.	CITY	STATE	POPULATION	NUMBER OF PLANTS
1	New York	New York	7,894,862	12
2	Chicago	Illinois	3,369,359	4
3	Los Angeles	California	2,809,596	4
4	Philadelphia	Pennsylvania	1,950,098	4
5	Detroit	Michigan	1,513,601	6
6	Houston	Texas	1,232,802	7
7	Baltimore	Maryland	905,759	6
8	Dallas	Texas	844,401	6
9	Washington	D.C.	756,510	2
10	Cleveland	Ohio	750,879	3
11	Indianapolis	Indiana	744,743	3
12	Milwaukee	Wisconsin	717,372	3
13	San Francisco	California	715,674	2
14	San Diego	California	697,027	3
15	San Antonio	Texas	654,153	7
16	Boston	Massachusetts	641,071	2
17	Memphis	Tennessee	623,530	1
18	St. Louis	Missouri	622,236	3
19	New Orleans	Louisiana	593,471	4
20	Phoenix	Arizona	581,562	1
21	Columbus	Ohio	540,025	3
22	Seattle	Washington	530,831	2
23	Jacksonville	Florida	528,865	3
24	Pittsburgh	Pennsylvania	520,117	5
25	Denver	Colorado	514,678	3
26	Kansas City	Missouri	507,330	3
27	Atlanta	Georgia	497,421	1
28	Buffalo	New York	462,768	1
29	Cincinnati	Ohio	452,524	2
30	San Jose	California	445,779	0
31	Minneapolis	Minnesota	434,400	2
32	Fort Worth	Texas	393,476	3
33	Toledo	Ohio	383,818	2
34	Newark	New Jersey	382,288	1
35	Portland	Oregon	380,555	2
36	Oklahoma City	Oklahoma	368,856	2
37	Louisville	Kentucky	361,958	4
38	Oakland	California	361,561	1
39	Long Beach	California	358,633	2
40	Omaha	Nebraska	346,929	4
41	Miami	Florida	334,859	1
42	Tulsa	Oklahoma	330,350	1
43	Honolulu	Hawaii	324,871	1
44	El Paso	Texas	322,261	2
45	St. Paul	Minnesota	309,828	2
46	Norfolk	Virginia	307,951	3
47	Birmingham	Alabama	300,910	2
48	Rochester	New York	296,233	3
49	Tampa	Florida	277,767	4
50	Wichita	Kansas	276,554	4
			Total	152

The trend in recent years toward larger units, combined with the advent of commercial nuclear power generation and the institution of mine-mouth coal-fired plants has resulted in a greater number of plants being constructed in rural areas. Site selection for new generating facilities is not only governed by the factors cited, but increasingly by environmental considerations. The prevention and control of air and water pollution is undoubtedly as important as many of the traditional factors involved in the selection of new plant sites. Factors generally considered in decisions on plant location include land requirements, water supply, fuel supply and delivery, etc.

Land requirements are quite variable. For plants situated near population centers, land cost is a prime consideration. The largest consumers of land are the fuel storage area, ash disposal area and water cooling ponds, lakes etc. if utilized. Since they are public utilities, power generating plants must have sufficient fuel storage capacity to allow uninterrupted operation for the duration of a major transportation strike. This means that unless the plant is very near its source of supply, it must have a storage capability up to approximately three month's fuel. Even mine-mouth plants must have fuel storage to allow them to withstand a miners' strike.

Most steam plants require water for two main purposes - boiler feed water make-up and steam condensation. The cost of preparation of the high purity boiler feed water required by modern boilers is a function of the purity of the source water. It is possible to use saline water for cooling purposes, but it cannot be used in a boiler. Preparation of boiler feed from saline water by evaporation or reverse osmosis is generally quite expensive. The availability of large quantities of cooling water has traditionally affected the decisions made regarding plant location. In areas where water is critically short, recirculation of cooling water using cooling towers or ponds has been widely practiced. This subject is discussed in detail in subsequent sections of this report.

Plant location may also be influenced by energy transportation costs. The cost of transmission of energy as electricity must be weighed against the cost of transporting fuel. Generally, fuel availability and economic factors will be the major considerations regarding the relationship between fuel and plant siting.

The trend in siting of generating plants using open-cycle cooling is toward locations on oceans, estuaries and lakes.

Of the plants installed near 1960, approximately 80% are on rivers, 10% on lakes, 10% on estuaries and 2% used municipal water. For the plants installed in the 1970's, approximately 50-60% are on rivers, 20-30% on lakes, 15% on estuaries, 2% on municipal water and 2% on oceans.

The methods used to control atmospheric pollution by stack gases vary. With plants burning solid fuel, a particulate emission problem may exist. The usual control system is the electrostatic precipitator. Finely divided solid particles suspended in a gas stream will accept an electrostatic charge when they pass through an electrical field. If they are then passed between two oppositely charged plates, they are attracted to one of the plates, depending on the polarity of the charges. On the plates they agglomerate and may be removed by rapping the plates. This operation is usually carried out at temperatures between 121° and 177°C (250-350°F). Finely divided solids may also be removed from the vent gases by using bag filters or by intimately contacting them with water in a venturi scrubber or similiar device.

Sulfur dioxide in stack gases can present another air pollution problem. This, of course, is most easily controlled by firing low sulfur fuel, which is not always readily available. Many alternatives have been proposed to remove the SO_2, and several are being used on a commercial scale. Most involve neutralization of the acid SO_2 with alkaline materials such as soda ash, lime, limestone, magnesia or dolomite, and ammonia. The processes developed to date consist of both once-through and recycle systems. A detailed analysis of air pollution control systems which produce a liquid waste stream is presented in another section of this report.

Categorization

The Act requires, for the purposes of assessment of the best practicable control technology currently available, that the toal cost of application of technology in relation to the effluent reduction benefits to be achieved from such application be considered. Other factors to be considered are the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, nonwater quality environmental impact (including energy requirements) and other factors as deemed appropriate. For best available technology economically achievable the Act substitutes "cost of achieving such effluent reduction" for "total cost ... in relation to effluent reduction benefits..." For new source standards which reflect the greatest degree of effluent reduction achievable through the application of the best available demonstrated control technology, processes, operating methods, or other alternatives, the Act requires only the consideration of the cost of achieving such effluent reduction and any nonwater quality environmental impact and energy requirements.

There are two radically different types of waste produced by steam electric powerplants. The first type consists of the essentially chemical wastes which originate from different processes and operations within a plant. These wastes are highly variable from plant to plant, depending on fuel, raw water quality, processes used in the plant and other factors. Some waste streams are not directly related to individual generating units but result from auxiliary process systems such as water treatment, ash disposal, housekeeping operations, and air pollution control. However, all of these waste streams are at least in a qualitive way comparable to waste streams produced by other manufacturing operations.

The second type of waste consists of the waste heat produced by the plant and disposed to the environment through the cooling water system. As previously indicated, waste heat is an integral part of the process of producing electric energy. As long as electric energy is produced by the use of thermal energy from fuels to produce steam, waste heat will be produced, and will ultimately have to be dissipated to the environment. Under present day technology, the atmosphere is the final recipient for this heat, but water is generally used as an intermediate recipient. The choices available in the control of thermal discharges therefore in most cases are limited to accelerating the transfer of the waste heat from water to the atmosphere. There is no available means of significantly reducing the waste heat itself.

Furthermore, while the technology for affecting this transfer is available, its application is dependent on many factors not directly associated with the production process. The effectiveness of heat transfer devices is to some degree governed by atmospheric conditions. The achievement of any specific level of reduction does not follow the type of cost - effectiveness curve associated with the removal of more conventional pollutions.

The basic categorization in this report therefore is to separate consideration of the chemical wastes from the effects of thermal discharges. Within the chemical waste category, each plant is considered as a whole and subelements have been established according to the type of wastes produced by each plant. In the consideration of thermal discharges, each generating unit is considered separately.

Chemical Wastes

The origin and character of chemical wastes within a powerplant is dependent upon the factors indicated above. Plants utilizing different fuels will produce different wastes to the degree that certain waste streams are completely absent in plants employing one type of fuel. Coal pile runoff is not a problem in oil-fired plants, and similarly ash sluicing is not necessary in gas-fired plants. Nuclear plants have closed waste systems to contain any waste which is, or may be, radioactive. These wastes are handled in a manner prescribed by the Atomic Energy Commission, and are not relevant to the categorization of the industry for the purposes of this project. As a result, many of the waste streams present in fossil-fired plants are not normally present, or of concern in a nuclear plant.

Another factor, such as raw water quality, will determine the type of water treatment employed within a specific plant, and in turn the wastes produced from water treatment processes. Although these wastes are extremely variable, depending upon the treatment employed (clarification, softening, ion exchange, evaporation, etc.), they are wastes which are common to all powerplants regardless of fuel or other factors. Other waste streams depend upon the specific characteristics of the particular plant in question.

As a result, the industry has been categorized for chemical waste characteristics by individual waste sources. The basis of evaluation of plants in the industry will be a combination of the appropriate waste sources for a particular powerplant. Guidelines will be established for each waste source, and can then be applied and utilized in the manner of a building-block concept. Waste streams may be combined, and in many cases this would have obvious advantages, and the appropriate guidelines would then also be combined for application to the new waste stream. Subcategories have been based on distinguishing factors within groups of plants. Table IV-5 provides the informal categorization for the purposes of the development of effluent limitations guidelines and standards for chemical wastes, and Table IV-6 shows the applicability of the

TABLE IV-5
CHEMICAL WASTE CATEGORIES

I. Condenser Cooling System
    A. Once-through
    B. Recirculating

II. Water Treatment
    A. Clarification
    B. Softening
    C. Ion Exchange
    D. Evaporator
    E. Filtration
    F. Other Treatment

III. Boiler or PWR Steam Generator
    A. Blowdown

IV. Maintenance Cleaning
    A. Boiler or PWR Steam Generator Tubes
    B. Boiler Fireside
    C. Air Preheater
    D. Misc. Small Equipment
    E. Stack
    F. Cooling Tower Basin

V. Ash Handling
    A. Oil-Fired Plants
        1. fly ash
        2. bottom ash
    B. Coal-Fired Plants
        1. fly ash
        2. bottom ash

VI. Drainage
    A. Coal Pile
    B. Contaminated Floor and Yard Drains

VII. Air Pollution Control Devices
    A. SO_2 Removal

VIII. Miscellaneous Waste Streams
    A. Sanitary Wastes
    B. Plant Laboratory and Sampling Systems
    C. Intake Screen Backwash
    D. Closed Cooling Water Systems
    E. Low-Level Rad Wastes
    F. Construction Activity

TABLE IV-6
APPLICABILITY OF CHEMICAL WASTE CATEGORIES BY TYPE OF FUEL

Process or Operation	Nuclear	Coal	Oil	Gas
I. Condenser Cooling System				
A. Once-through	X	X	X	X
B. Recirculating	X	X	X	X
II. Water Treatment				
A. Clarification	X	X	X	X
B. Softening	X	X	X	X
C. Ion Exchange	X	X	X	X
D. Evaporator	X	X	X	X
E. Filtration	X	X	X	X
F. Other Treatment	X	X	X	X
III. Boiler or Generator Blowdown	X	X	X	X
IV. Maintenance Cleaning				
A. Boiler or Generator Tubes	X	X	X	X
B. Boiler Fireside		X	X	X
C. Air Preheater		X	X	X
D. Misc. Small Equipment		X	X	X
E. Stack		X	X	
F. Cooling Tower Basin	X	X	X	X
V. Ash				
A. Bottom Ash		X		
B. Fly Ash		X	X	
VI. Drainage				
A. Coal Pile		X		
B. Floor and Yard Drains		X	X	X
VII. Air Pollution (SO_2) Control Devices		X	X	
VIII. Miscellaneous				
A. Sanitary Wastes	X	X	X	X
B. Plant Laboratory and Sampling Streams	X	X	X	X
C. Intake Screen Backwash	X	X	X	X
D. Closed Cooling Water Systems	X	X	X	X
E. Low-Level Rad Wastes	X			
F. Construction Activity	X	X	X	X

categories to plants utilizing the four basic fuels for producing electricity.

Thermal Discharges

The most obvious factor influencing the rejection of waste heat to navigable waterbodies is the type of condenser cooling system utilized within a plant. Powerplants which recycle cooling water through a cooling device only affect the receiving water by way of the relatively small blowdown stream from the cooling tower, pond, etc. On the other hand, plants operating with once-through cooling systems are primarily responsible for the discharge of waste heat to receiving waters. Consequently, the basic subcategorization for thermal discharge characteristics divides the generating units by type of cooling system utilized, into plants having recirculating cooling systems, or once-through cooling systems.

As indicated above, the primary factor in consideration of waste heat rejection is the generating unit in question. Therefore, subcategorization of once-through cooling systems has been made on a unit, rather than a plant basis. The evaluation of generating units to further sub-divide the industry considered in detail the various factors described in this section of the report; namely, fuel, size, age, and site characteristics and mode of operation utilized. The evaluation of these factors will be described below to provide the rationale for the subcategorization developed.

The consideration of fuel as a factor in waste heat rejection from a powerplant essentially focuses on the differences between present nuclear and fossil-fueled units. In general, the inherent characteristics of a light water nuclear unit make it less efficient than fossil-fired units. This difference in efficiency results in the rejection of more waste heat to receiving waters from nuclear units than from comparable fossil units. Subsequent sections of the report will discuss the technical factors which cause this difference.

Nuclear units generally have basic similarities with regard to age, size, location and utilization which also tend to differentiate them from fossil-fueled units. Nuclear units can be generally classified as being relatively new, relatively large, located in rural or semi-rural areas, and operated as base-load facilities.

These factors are extremely variable when applied to fossil-fueled units on a broad basis. Also, the thermal waste characteristics of units burning different fossil fuels indicate that there is no basis for distinguishing between fossil fuels for the thermal categorization of the industry. Consequently, the basic subcategorization of once-through cooling systems divides the industry between nuclear and fossil-fueled units.

A major factor of concern with regard to fossil-fueled generating facilities is the utilization of individual units. An earlier portion of this section of the report described the relationship of this factor with age and with efficiency or heat rate of a generating unit. In addition to this aspect of utilization, another point of concern is the relationship between utilization and the cost of installing facilities to treat waste heat. Utilization is significant in economic analysis, as it provides the operating time against which capital costs may be applied. Furthermore, utilization reflects the effluent heat reduction benefit to be achieved by the application of control technology. As defined earlier, the utilization aspect of power generation is defined by peaking, cycling and base load generating facilities. Peaking units are defined as facilities which have annual capacity factors less than 0.20, while cycling units have annual capacity factors between 0.20 and 0.60 and base-load units have annual capacity factors in excess of 0.60.

Some difficulty could be encountered, for the purpose of effluent limitations, in determining the level of utilization that a generating unit will achieve in the years to come. It is known, however, that all of the nuclear steam-electric generating units and all of the high-pressure, high-temperature, fossil-fueled units 500 megawatts (Mw) and larger have been designed as base-load units. Almost all nuclear units are 500 Mw and larger.

All of these units presently operating were placed into service since 1960 (excepting only one small nuclear unit initially operated in 1957). The units placed in service during the 1960's had 15 or more years of base-load service ahead of them as of 1970, and would thus have 8 or more years of base-load life as of 1977.

A further difficulty that could be encountered in determining the level of utilization of a generating unit relates to the fact that the only official record of the utilization of individual generating units is the Form 67 "Steam-Electric Plant Air and Water Quality Control Data", which must be filed annually with the Federal Power Commission. Utilities are required to report the capacity and average annual capacity factor (level of utilization) for each boiler, but not the turbine-generator. Furthermore, prior to 1950, individual boilers were kept small, in large part because boiler outages were rather numerous, so that it was common design practice to provide multiple boilers and steam header systems to supply a turbine-generator. Some stations have the headers connected to multiple turbine-generators. Hence, the problem could arise in these cases as to what comprises a generating unit (boiler(s) plus turbine-generator) and what is its level of utilization. Furthermore, the problem of applying a closed-loop cooling system could be more difficult where multiple boilers supply single or multiple turbine-generators due to the physical and operating problems arising from the multiple connections involved.

However, advances in metal technology since 1950, with associated lower costs of larger units, have made it economical and reliable to have one boiler per turbine-generator. The trend to the larger, one boiler per turbine-generator units began to be significant when the first 300 Mw unit was placed into service in 1955. From 1930 until that time the largest steam electric unit in the U.S. was about 200 Mw. Hence, for units 300 Mw and larger, the unit itself and its level of utilization are clearly defined and the physical and operating problems associated with a closed-loop cooling system and arising from the multiple connections involved are not encountered.

Age was identified in the Act as a factor to be taken into account in the establishment of effluent limitation guidelines and performance standards. As indicated above, the interrelationship between age, utilization and efficiency, has generally been well documented in the steam electric generating industry. Age is also important because the remaining life of equipment provides the basis for the economic write-off of capital investment. Consequently, age is of significance in subcategorizing steam electric generating units not only for technical reasons, but also for economic considerations.

Federal Power Commission depreciation practices indicate the estimated average service life of equipment for steam elecelectric production to be 36 years [87]. Figure IV-10, which shows the improvement of efficiency in the generation of electricity since 1920, indicates a sudden dip in the curve in approximately 1949, or 24 years ago. Based on this process factor and the anticipated service life of equipment, it was decided, for the purposes of the cost analysis, to segment fossil-fueled units by age, with 6 (six-year) segments defining the range of age with regard to generating units.

Site characteristics were considered as a possibility for subcategorization of the industry for thermal discharges. The basic consideration involving location related to the situation of a plant with regard to its cooling water source (ocean, river, estuary, lake, etc.). However, categorization along these lines would in reality violate the intent of the Act, which stresses national uniformity of application and is technology oriented. The control and treatment of waste heat is essentially an internal matter within a powerplant. Absolute location will influence the cost of such control and treatment, but will not generally determine its feasibility. This type of location factor is primarily related to environmental considerations, which are taken into account under Sections 303 and 316 of the Act. Consequently, it was decided not to establish any subcategories for thermal waste characteristics based on location.

Size was another factor which conceivably could form the basis for thermal waste subcategorization of the steam electric powerplant industry. Among those technical and economic factors considered relative to the size of a unit were availability and degree of practicability of control and treatment technology, unit costs of control and treatment technology and their relation to other generating costs, and system reliability. A basis for a size subcategorization would be the precedent established by the Federal Power Commission with regard to the requirements for filing Form 67, "Steam Electric Plant Air and Water Quality Control Data". The FPC does not require filing of this form by powerplants smaller than 25 megawatts, or plants larger than 25 megawatts which do not belong to a utility system with a capacity equal to, or greater than 150 megawatts. Consequently, the data available from this source would not cover the numerous small generating plants under 25 megawatts.

As a result of evaluation of the factors outlined above, informal segmentation for the purposes of the development of effluent limitations guidelines and standards for heat includes a division between nuclear and fossil units and further division of fossil units based on utilization, all followed by age considerations, and finally segmentation by size of unit as defined by cost and other considerations.

Summary

In summary, the most significant of the basic components of all steam electric powerplants which relate to waste water characteristics are the fuel storage and handling facilities, water treatment equipment, boiler, condenser, type of cooling system, and auxiliary facilities. Steam electric powerplants (plants) are comprised of one or more generating units. A generating unit consists of a discrete boiler, turbine-generator and condenser system. Fuel storage and handling facilities, water treatment equipment, electrical transmission facilities, and auxiliary components may be a part of a discrete generating unit or may service more than one generating unit. The characteristic quantity and intensity of the waste heat transferred in the condenser from the expended steam to the cooling water is related to the combined characteristics of the plant components that are its source.

The general subcategorization rationale is summarized in Table IV-7 the subcategorization rationale for heat is summarized in Table IV-8 and the subcategorization rationale for pollutants other than heat is summarized in Table IV-9.

The degree of nonthermal effluent reductions that can be achieved by the application of specific control and treatment technologies are related to the type of source components involved, and further to water use and quality and other considerations peculiar to individual plants. Both unit and plant related characteristics affect the degree of practicability of applying nonthermal waste water control and treatment technology.

Accordingly, the general categorization scheme developed was approached from the basis that separate subcategorizations would be constructed for thermal characteristics and for nonthermal characteristics so that the rationale supporting the one would not necessarily be supportive of the other, and candidate approaches to either could be utilized or discarded on their own merits. Numerous factors were considered as candidates for further subcategorization and are as follows: the age of equipment and facilities, the process employed, waste source (nonthermal characteristics), nonwater quality environmental impact (including energy requirements), site characteristics, size of plant, type of thermal control employed, fuel utilized, and utilization characteristics of the plant, with only the age of unit, its utilization, its generating capacity (size) and type of thermal control employed qualifying as further bases for subcategorization of thermal discharges, and waste source for nonthermal discharges. Many of the above factors are

Table IV-7

GENERAL SUBCATEGORIZATION RATIONALE

Subcategorization for heat is approached separately from subcategorization for other pollutants because:

- Control and treatment technology for heat relate primarily to the characteristics of generating units, while nonthermal control and treatment technologies relate primarily to characteristics of stations.
- Control and treatment technologies are dissimilar; and
- The costs of thermal control and treatment technology are much greater than nonthermal control and treatment technologies.

Table IV- 8

SUBCATEGORIZATION RATIONALE FOR POLLUTANTS OTHER THAN HEAT

Characteristic of Plant	Need for Subcategorization	Rationale
Utilization (base-load, cyclic, or peaking)	No	Costs versus effluent reduction benefits vary significantly but are small in all cases
Age	No	Costs versus effluent reduction benefits vary significantly but are small in all cases
	Yes	Certain technologies are practicable for new sources but not for others
Fuel	No	Effects on costs versus effluent reduction benefits are not significant
Size	No	Costs versus effluent reduction benefits are greater for small plants but still relatively small
Land Availability	No	Treatment technology includes small-sized configured equipment as well as lagoon-type facilities
Water Consumption	No	Negligible consumption
Non-Water Quality Environmental Impact (including energy consumption)	No	Not significant
Process Employed	Yes	Practicability of treatment technology is related to the volumes of waste water treated, therefore subcategories should be based on the specific waste water streams, especially those of significant volume
Climate	No	Not significant except for effect on rainfall runoff treatment costs, but costs versus effluent reduction benefits are approximately the same and costs are relatively small

Table IV-9

SUBCATEGORIZATION RATIONALE FOR HEAT

Characteristic of Unit	Need for Subcategorization	Rationale
Utilization (Base-load, cyclic, or peaking)	Yes	Coupled with age, this factor determines the incremental cost of production versus the effluent reduction benefits related to the thermal control technology.
Age	Yes	Coupled with utilization, this factor determines the incremental cost of production versus the effluent reduction benefits related to the thermal control technology.
Fuel	Yes	Nuclear-fueled units reject significantly more heat to cooling water than do comparible fossil-fueled units.
Size	Yes	Retrofit outages in small plants (typically older peaking plants) and small systems would be more likely to cause reliability problems. Size may affect retrofit costs. Size is generally related to age and utilization. Counterbalancing of cost variations is not as likely for small plants and systems.
Process Employed	No	All significant differences already accounted for by factors of utilization, age, fuel, and size.
Land Availability	Yes	Numerous units, due to urban locations, have insufficient land available to implement the control technology.
Water Consumption	No	Where required water consumption rights can add an incremental but insignificant cost over the cost of water use rights otherwise required.
Climate	No	Variabilities are primarily cost related and taken into account in the cost analysis
Non-Water Quality Environmental Impacts		
● Saltwater Drift	Yes	While technology is available to limit drift to very low levels, significant impacts could occur for units in urban areas on saltwater bodies.
● Fogging	No	Technology is available to abate fogging in the few cases where it might otherwise have a significant impact.
● Noise	No	Technology is available to abate noise in the few cases where it might otherwise have a significant impact.
● Aesthetics	No	Would only be a problem in a case-by-case evaluation of alternatives.

related as previously discussed. A further example is the relation between age of generating units and their capacity factor, as shown in Table IV-10.

Certain further factors can be identified each of which are not sufficiently significant to warrant their inclusion in the general subcategorization framework but which will be examined in detail in subsequent sections of this document. Some of these factors are the following: available land characteristics, size of the unit, accessibility of existing cooling system, ability of existing structures to accommodate a new recirculating cooling system, requirements imposed by nearby land uses (drift, fogging, noise, structure height), climatic considerations (wind, relative humidity), soil strengths, significance of consumptive use of water, main condenser cooling water flow rate, unit heat rate, wet-bulb temperature, back-end loading, cooling tower plume abatement, noise abatement, aircraft safety, system reliability requirements, and characteristics of intake water (temperature, concentrations of constituents).

Table IV-10

DISTRIBUTION OF U.S. GENERATING CAPACITY BY AGE AND CAPACITY FACTOR*

Year Installed	Capacity Factor			
	0 - 0.2	0.2 - 0.4	0.4 - 0.6	0.6 +
Before 1956	11,000 Mw	7,000 Mw	13,000 Mw	20,000 Mw
1956-1960	2,000	5,000	15,000	10,000
1961-1971	1,000	10,000	36,000	36,000
1972-1978	0	0	8,000	81,000

* Source: FPC data

PART A

CHEMICAL WASTES

SECTION V

WASTE CHARACTERIZATION

Introduction

In this part of the study (Part A) only the nonthermal, or chemical wastes are dealt with. Part B of the report deals with thermal discharges.

Chemical wastes produced by a steam electric powerplant can result from a number of operations at the site. Some wastes are discharged more or less continuously as long as the plant is operating. Some wastes are produced intermittently, but on a fairly regularly scheduled basis such as daily or weekly, but which are still associated with the production of electrical energy. Other wastes are also produced intermittently, but at less frequent intervals and are generally associated with either the shutdown or startup of a boiler or generating unit. Additional wastes exist that are essentially unrelated to production but depend on meteorological or other factors.

Waste waters are produced relatively continously from the following sources (where applicable): cooling water systems, ash handling systems, wet-scrubber air pollution control systems, boiler blowdown.

Waste water is produced intermittently, on a regular basis, by water treatment operations which utilize a cleaning or regenerative step as part of their cycle (ion exchange, filtration, clarification, evaporation).

Waste water produced by the maintenance cleaning of major units of equipment on a scheduled basis either during maintenance shutdown or during startup of a new unit may result from boiler cleaning (water side), boiler cleaning (fire side), air preheater cleaning, stack cleaning, cooling tower basin cleaning and cleaning of miscellaneous small equipment. The efficiency of a powerplant depends largely on the cleanliness of its heat transfer surfaces. Internal cleaning of this equipment is usually done by chemical means, and requires strong chemicals to remove deposits formed on these surfaces. Actually the cleaning is not successful unless the surfaces are cleaned to bare metal, and this means in turn that some metal has to be dissolved in the cleaning solution. Cleaning of other facilities is accomplished by use of a water jet only.

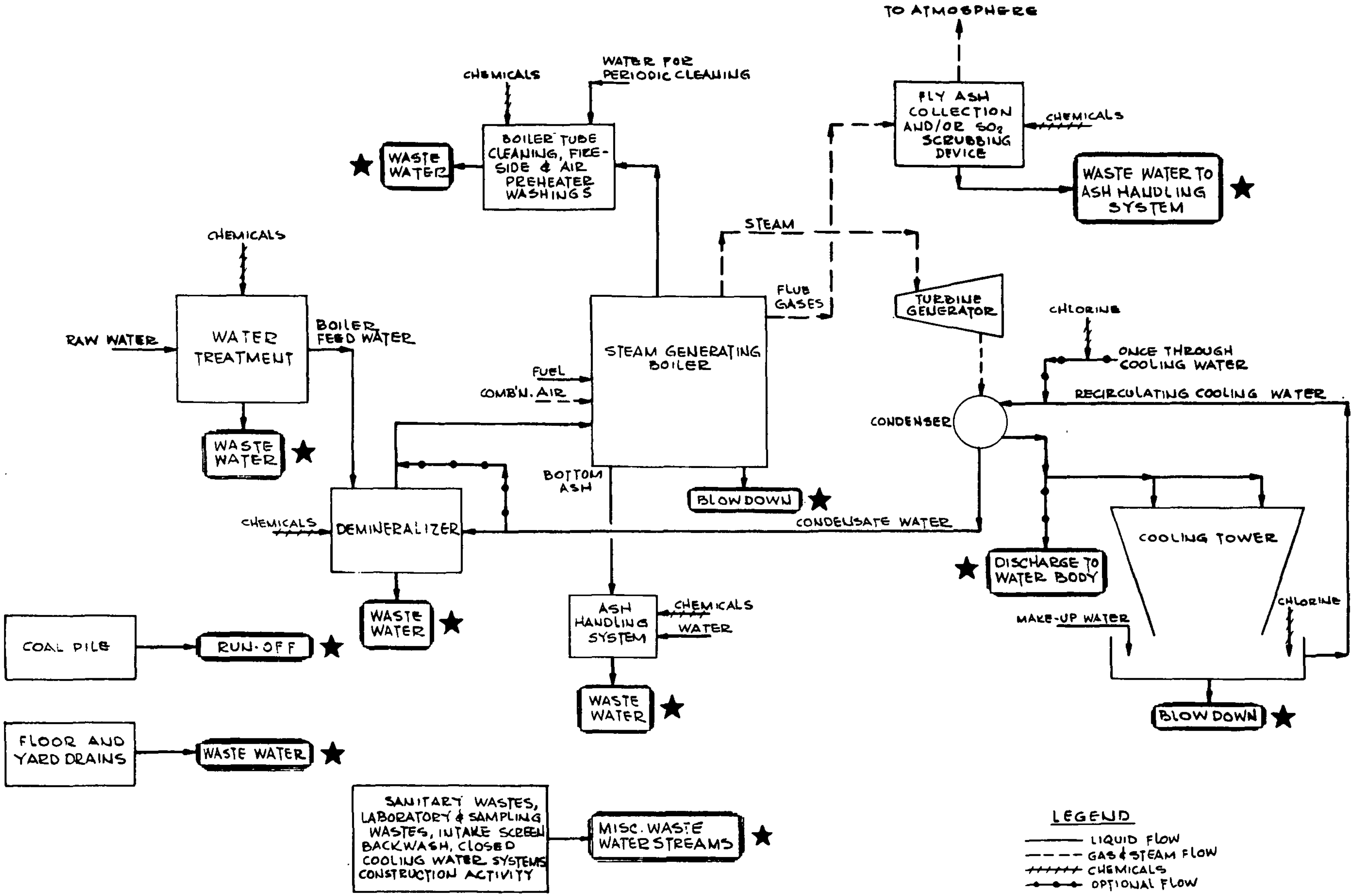
Rainfall runoff results in drainage from coal piles, floor and yard drains, and from construction activity.

A diagram indicating sources of chemical wastes in a fossil-fueled steam electric powerplant is shown in Figure A-V-1. A simplified flow diagram for a nuclear plant is shown in Figure A-V-2. Heat input to the boiler comes from the fuel. Recycled condensate water, with some pretreated make-up water, is supplied to the boiler for producing steam. Make-up requirements depend upon boiler operations such as blowdown, steam soot blowing and steam losses. The quality of this make-up water is dependant upon raw water quality and boiler operating pressure. For example, in boilers where operating pressure is below 2.8 MN/sq m (400 psi), good quality municipal water may be used without pretreatment. On the other hand, modern high-pressure, high-temperature boilers need a controlled high-quality water. The water treatment includes such operations as lime-soda softening, clarification, ion exchange, etc. These water treatment operations produce chemical wastes. According to the FPC[234], the principal chemical additives reported for boiler water treatment are phosphate, caustic soda, lime and alum.

As a result of evaporation, there is a build-up of total dissolved solids (TDS) in the boiler water. To maintain TDS below allowable limits for boiler operation, a controlled amount of boiler water is sometimes bled off (boiler blowdown).

The steam produced in the boiler is expanded in the turbine generator to produce electricity. The spent steam proceeds to a condenser where the heat of vaporization of the steam is transferred to the condenser cooling system. The condensed steam (condensate) is recycled to the boiler after pretreatment (condensate polishing) if necessary, depending upon water quality requirements for the boiler. As a result of condensate polishing (filtration and ion exchange), waste water streams are created.

In a nonrecirculating (once-through) condenser cooling system, warm water is discharged without recycle after cooling. The cool water withdrawn from an ocean, lake, river, estuary or groundwater source may generate biological growth and accumulation in the condenser thereby reducing its efficiency. Chlorine is usually added to once-through



TYPICAL FLOW DIAGRAM - STEAM ELECTRIC POWER PLANT (FOSSIL-FUELED)
SOURCES OF CHEMICAL WASTES
FIGURE A-V-1

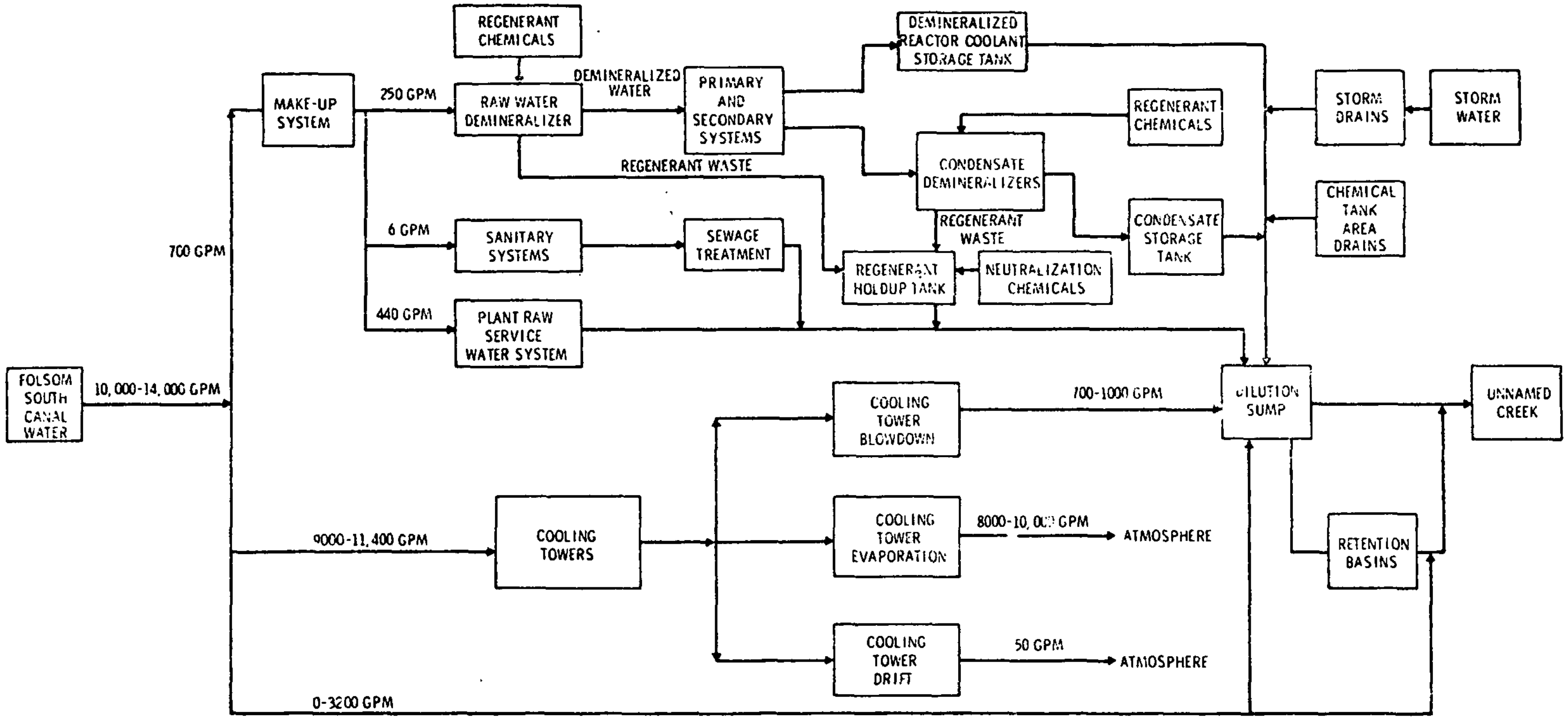


Figure A-V- 2

SIMPLIFIED WATER SYSTEM FLOW DIAGRAM FOR A NUCLEAR UNIT[108r] condenser cooling systems to minimize this fouling of heat transfer surfaces. Chlorine is therefore a parameter which must be considered for nonrecirculating cooling water systems.

Cooling devices such as cooling towers are employed in the recirculating cooling systems. Bleed streams (blowdown) must generally be provided to control the build-up of certain dissolved solids or total dissolved solids within the recirculating evaporative cooling systems. These streams may also contain chlorine and other chemical additives. According to the FPC[234], the principal chemical additives reported for cooling water treatment are phosphate, lime, alum and chlorine.

As a result of fossil-fuel combustion in the boiler, flue gases are produced which are vented to the atmosphere. Depending upon the type of fossil fuel, the flue gases carry certain amounts of entrained particulate matter (fly ash) which are removed in mechanical dust collectors, electrostatic precipitators or wet scrubbing or collector devices. Thus fly ash removal may create another waste water stream in a powerplant.

A portion of the noncombustible matter of the fuel is left in the boiler. This bottom ash is usually transported as a slurry in a water sluicing operation. This ash handling operation presents another possible source of waste water within a powerplant.

Depending upon the sulfur content of the fossil fuel, SO_2 scrubbing may be carried out to remove sulfur emissions in the flue gases. Such operations generally create liquid waste streams. Note that SO_2 scrubbing is not required for gas-fired plants, or facilities burning oil with a low sulfur content. Nuclear plants, of course, have no ash or flue gas scrubbing waste streams.

As a result of combustion processes in the boiler, residue accumulates on the boiler sections and air preheater. To maintain efficient heat transfer rates, these accumulated residues are removed by washing with water. The resulting wastes represent periodic (intermittent) waste streams.

In spite of the high quality water used in boilers, there is a build-up of scale and corrosion products on the heat transfer surfaces over a period of time. This build-up is usually due to condenser leaks, oxygen leaks into the water and occasional erosion of metallic parts by boiler water. Periodically, this scale build-up is removed by cleaning the boiler tubes with different chemicals - such as acids, alkali, and chelating compounds. These cleaning wastes, though occuring only periodically, contain metalic species such as copper, iron, etc. which may require treatment prior to discharge.

The build-up of scale in cooling tower basins and soot build-up in stacks require periodic washings and these operations also give rise to waste streams.

For coal-fired generating units, outside storage of coal at or near the site is necessary to assure continuous plant operation. Normally, a supply of 90 days is maintained. Coal is stored either in "active" piles or "storage" piles. As coal storage piles are normally open, contact of coal with air and moisture results in oxidation of metal sulfides, present in the coal, to sulfuric acid. The precipitate trickles or seeps through the coal. When rain falls on these piles, the acid is washed out and eventually winds up in coal pile runoff, creating another waste stream. Similarly, contaminated floor and yard drains are another source of pollution within the powerplant.

Besides these major waste streams, there are other miscellaneous waste streams in a powerplant such as sanitary wastes, laboratory and sampling wastes, etc. which are also shown in Figure No. A-V-1.

In a nuclear-fueled powerplant, high quality water is used in the steam generating section. Conventional water treatment operations give rise to chemical waste streams similar to those in fossil-fueled powerplants. Similarly, the cooling tower blowdown is another waste stream common to both fossil-fueled and nuclear fueled powerplants. Some wastes in a nuclear plant contain radioactive material. The discharge of such wastes is strictly controlled and is beyond the scope of this project. However, the steam generator in a PWR plant is a secondary system, having a blowdown and periodic cleaning wastes which are not radioactive. Some of the disposal problems associated with low-level radiation wastes from nuclear fuel powerplants are briefly described in this report.

Data was accumulated from different sources to characterize the various chemical wastes described above. The sources of data include:

a. Plants visits and collection of samples for analysis

b. Permit applications submitted by powerplants to the U.S. Army Corps of Engineers.

c. Tennessee Valley Authority (TVA) reports of operating plants

d. EPA Region II - questionnaire

e. EPA Region V - summary of permit applications data by National Environmental Research Center, Corvallis

f. Southwest Energy Study - Appendices

g. U.S. Atomic Energy Commission, Environmental Impact Statements

h. In-house data at Burns and Roe, Inc.

These data were included in Appendix 2 of the Development Document supporting the proposed effluent limitations guidelines and standards for steam electric powerplants, which was issued in March, 1974. A code system was used for individual plant identification.

Based on these data and other industrial and governmental literature, recommended effluent limitations guidelines proposed are developed for chemical wastes from the following operations in steam electric powerplants.

I. Condenser Cooling System
    A. Once-Through
    B. Recirculating

II. Water Treatment
    A. Clarification
    B. Softening
    C. Ion Exchange
    D. Evaporator
    E. Filtration
    F. Other Treatment

III. Boiler or PWR Steam Generator Blowdown

IV. Maintenance Cleaning
    A. Boiler or PWR Steam Generator Tubes
    B. Boiler Fireside
    C. Air Preheater
    D. Misc. Small Equipment
    E. Stack
    F. Cooling Tower Basin

V. Ash Handling
    A. Oil-Fired Plants Fly Ash
    B. Coal-Fired Plants
        1. fly ash
        2. bottom ash

VI. Rainfall Runoff
    A. Materials Storage (Coal Pile)
    B. Construction Activity

VII. Air Pollution Control Devices

VIII. Miscellaneous Waste Streams
    A. Sanitary Wastes
    B. Plant Laboratory and Sampling Streams
    C. Intake Screen Backwash
    D. Closed Cooling Water Systems
    E. Low-Level Rad Wastes
    F. Floor Drains
    G. Others

Once-Through Cooling Systems

The common biocides used are chlorine or hypochlorites. The amount of chlorine dosage varies from site to site and depends upon the source of cooling water and ambient conditions. For example, in winter the biological growth is normally not as pronounced as in spring or summer. Consequently, chlorine demand is less in winter. Normally, the chlorine is supplied as a slug rather than by continuous injection. The frequency of chlorine dosage differs in each plant, and may vary from once a day to ten times a day. Treatment duration varies between 5 minutes and 2 hours. Chlorination results in residual chlorine concentrations in the range of 0.1 to 1 mg/l (ppm). Higher concentrations can be found in cases where higher level organisms, such as jellyfish, or eels, tend to accumulate on condenser surfaces.

Since the waste characteristics of once-through cooling systems designed for economical operation and the control technology for the reduction of the discharge of pollutants from this source reflect in many instances the same or similar technologies, these aspects are discussed in more detail in Section A-VII of the Development Document.

Recirculating Cooling Systems

In the operation of a closed, evaporative cooling system, the bulk of the warm circulating water returning to the cooling tower, pond, etc. is cooled by the evaporation of a small fraction of it. During this evaporation only water vapor is lost, except for leakage and some net entrainment of droplets in the air draft (drift loss), and the salts dissolved in the remaining liquid become more concentrated. Most natural waters contain calcium (Ca^{++}), magnesium (Mg^{++}), sodium (Na^{+}), and other metallic ions, and carbonate (CO_3^{--}), bicarbonate (HCO_3^{-}), sulfate (SO_4^{--}), chloride (Cl^{-}) and other acidic ions in solution. All combinations of these ions are possible. When the concentration of ions in any possible combination exceeds the solubility limits under the existing conditions, the corresponding salt will precipitate. Some of these salts are characterized by reverse solubility, that is, their solubility decreases when the temperature rises. If water saturated with such a salt leaves the cooling tower at the cool water temperature, as the water is heated in passing thru the condenser the solubility will decrease and the salt will deposit as a scale on the condenser tube walls and hinder heat transfer thru the tubes.

According to Reference 144, the formation of scale may be controlled in several ways. The most common is to blowdown a portion of the circulating water stream and replace that quantity with fresh water so that the circulating water does not reach saturation at any time. Blowdown therefore is the constant or intermittent discharge of a small portion of the circulating water in a closed cooling system to prevent a buildup of high concentrations of dissolved solids. The blowdown (B) is a function of the available makeup (B+D+Ev) water quality and is related to evaporation (Ev) and drift (D) in the following manner:

$$C = (B + Ev + D)/(B + D)$$

In this equation, C equals cycles of concentration, a dimensionless number which expresses the number of times the concentration of any constituent is multiplied from its original value in the makeup water. (It does not represent the number of passes through the system). B, Ev, and D are expressed in consistent units (e.g. percent of circulating water flow rate or actual flow rate).

For average makeup water quality, conventional practice sets the value of C between 4 and 6. For extremely high quality makeup water (or treated water) C values of 15 and above are possible. For salt or saline water, C values as low as 1.2 to 1.5 may be required. This is usually not a materials or operating limit, but rather a means of preventing biological damage from blowdown salinity.

The chemical characteristics of the recirculating water (treated or untreated) determine the maximum C value. Table A-V-1 provides some "rules of thumb" to be used in establishing the maximum C value. Note that the C subscript designations used in the table represent individual constituent concentrations and should not be confused with C, cycles of concentration used above.

The "Limitation" column in Table A-V-1 indicates the maximum value allowed in the recirculating water for each chemical characteristic given. The maximum C value would be established when any one of the "Limitations" is exceeded. Note that this table provides "rule of thumb" estimates, which may not be applicable to unique water quality problems.

The equation for C can be rewritten for blowdown (B):

$$B = \frac{Ev - D(C-1)}{C - 1}$$

In order to minimize the total amount of makeup water and blowdown the cooling tower should be operated at as high a C value as possible. The following data were computed using the above equation and illustrate the effect of C on the blowdown and makeup flow rates:

C (cycles of concentration)	Blowdown (cfs)	Makeup (cfs)
1.2	107	128
1.5	42.8	64.2
2.0	21.4	42.8
5.0	5.3	26.7
10.0	2.3	23.7
20.0	1.1	22.5

This table was developed assuming an evaporation rate (Ev) of 21.4 cfs and a drift rate (D) of 0.05 cfs (0.005% of 950 cfs).

There are several advantages to maintaining a high C value:

a. Minimizing the makeup water requirement, thus reducing the number of organisms entrained in the cooling water.

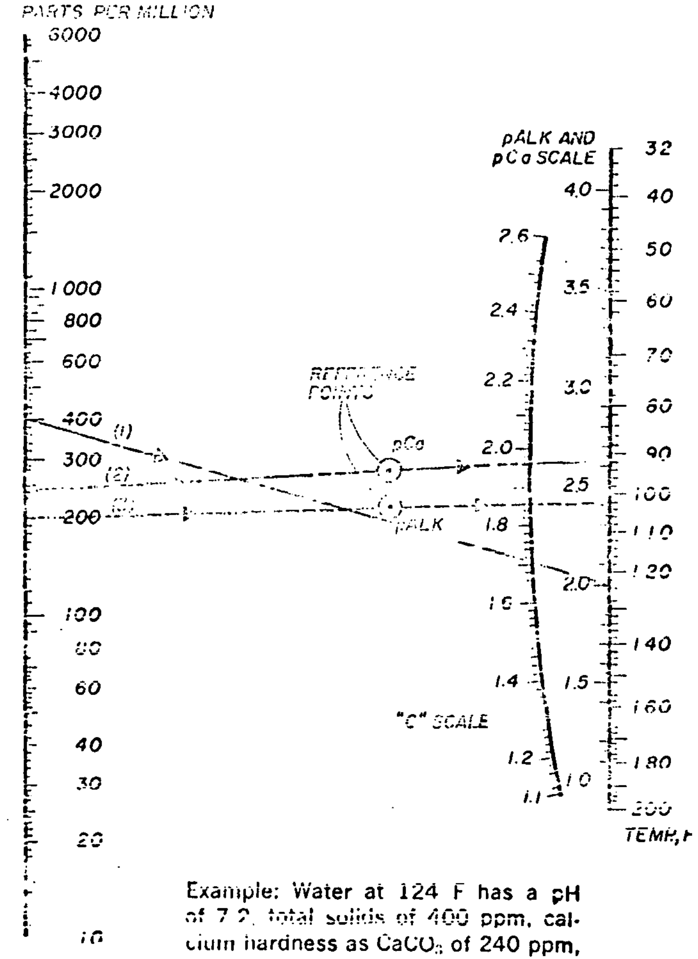
Table A-V-1

RECIRCULATING WATER QUALITY LIMITATIONS

Characteristic	Limitation	Comment
pH and Hardness	Langelier Saturation Index = 1.0	Langelier Saturation Index = pH-pHs where pH = measured pH pHs = pH at saturation with $CaCO_3$ See Figure A-V-3 for nomograph solution.
pH and Hardness with addition of proprietory chemicals for deposit control.	Langelier Saturation Index = 2.5	
Sulfate and Calcium	$(C_{SO_4}) \times (C_{Ca}) = 500,000$	C_{SO_4} = concentration of SO_4 in mg/l C_{Ca} = concentration of Ca in mg/l as $CaCO_3$
Silica	$C_{SiO_2} = 150$	C_{SiO_2} = concentration of SiO_2 in mg/l
Magnesium and Silica	$(C_{Mg}) \times (C_{SiO_2}) = 35,000$	C_{Mg} = concentration of Mg in mg/l as $CaCO_3$
Suspended Solids	C_{ss} = 400 mg/l	C_{ss} = concentration of ss in mg/l

Figure A-V-3
NOMOGRAM TO DETERMINE LANGELIER SATURATION INDEX

Courtesy Power Engineering



Example: Water at 124 F has a pH of 7.2, total solids of 400 ppm, calcium hardness as $CaCO_3$ of 240 ppm, and alkalinity as $CaCO_3$ of 196 ppm. Find the Langelier saturation index.

Solution: (1) Join 400 ppm on the lefthand scale with 124 F on the temperature scale. At intersection with C scale note value of 1.7. (2) Join 240 ppm with pCa reference point and extend to pCa scale. Read pCa = 2.62. (3) Join 196 ppm with pALK reference point, extend to pALK scale and read pALK = 2.40. Add the three values:

$$pH_S = C + pCa + pALK = 6.72$$
$$Index = pH - pH_S = 7.2 - 6.72 = +0.48$$

b. Minimizing the volume of blowdown water to be discharged.

c. Reducing the size and cost of makeup and blowdown handling facilities (i.e., pumps, pipes, screens, etc.).

Values for evaporation from cooling systems average about 0.75% of cooling water flow for every 10°F of condenser delta T for cooling towers and approximately 50% higher for cooling ponds. This is equivalent to a range of 15.0 to 30.0 gpm/Mw for cooling towers and 22.5 to 45.0 gpm/Mw for cooling ponds. Drift constitutes a relatively small portion of the required makeup water. For new cooling towers, drift losses can be kept as low as 0.005% of the cooling water flow for mechanical draft towers and 0.002% for natural draft towers. Drift losses for ponds are negligible. Estimates of the allowable blowdown flow based on these factors can be made once the cooling water flow, condenser delta T, and allowable concentration factors are known.

The heat content of the blowdown as a percent of condenser heat rejection can be quite variable. The heat content of the blowdown can vary from a fraction of 1% of the total condenser heat rejection to as high as 7 to 8% of this value. Higher rates of heat rejection in the blowdown are due to larger blowdown flows (smaller C values) required in salt water systems and systems that blowdown from the hot side of the system. Systems that blowdown from the cold side of the cooling system should contain no more than 1 to 2% of the condenser heat rejection.

Scale formation may be controlled by chemical means such as softening or ion exchange to substitute more soluble ions for the scale formers, such as Na^{+} substitution for Ca^{++} and Mg^{++}. Advantage may be taken of the greater solubility of some ions. For instance SO_4^{--} may be substituted for CO_3^{--} or HCO_3^{-}, as:

$$Ca\,CO_3 + H_2\,SO_4 = CaSO_4 + H_2O + CO_2(g)$$

$$Mg(HCO_3)_2 + H_2SO_4 = MqSO_4 + 2H_2O + 2CO_2(g)$$

In these reactions, CO_2 is released as a gas. Sulfates have a much greater solubility than carbonates and bicarbonates, and scale formation is reduced. Organic "sequestering" agents are used to tie up the insoluble metallic ions so that they cannot combine with the carbonates and bicarbonates to form scale. Many of these agents are proprietary compounds and their compositions are not generally known. The use of chemical dispersants and makeup water softening to reduce or eliminate blowdown at certain powerplants is discussed in Reference 22. Eventually the limit is reached and there must be some bleed through drift or blowdown although its quantity may be greatly reduced, resulting in higher concentrations. Data obtained from the study of fifteen plants reveals an extremely large variation in the parameters listed. Generally, the important pollutant parameters are: total suspended solids (TSS), pH, hardness, alkalinity, total dissolved solids and phosphorus.

In general, condenser materials are chosen so as to resist corrosion by the recirculating water. Consequently, chemicals are generally not required in the recirculating water for corrosion resistance, except in cases where the recirculating water (because of the make-up water quality) has high chloride concentrations chromates or other chemicals are added as corrosion inhibitors.

In recirculating systems, growth organisms such as algae, fungi and slimes occur because of the warm and moist environment. Such biological growth will affect condenser efficiencies and chlorine is commonly used as a biocide. The chlorine dosage is usually in slugs. The residual chlorine is generally in the range of 1 mg/liter. Higher residual chlorine concentrations may cause corrosion problems. In cooling towers with wood filling, sodium pentachlorophenate is sometimes added to inhibit fungi attack on wood. The chemicals are generally added to the cooling tower basin to ensure adequate mixing. Depending upon the chlorine dosage frequency (one to three times a day) and sodium salt addition, the concentration of these pollutants in the blowdown will vary for each case.

Since the waste characteristics of recirculating cooling systems designed for economical operation and the control technology for the reduction of the discharge of pollutants from this source reflect in many instances, the same or similar technologies, these aspects are discussed in more detail in Section A-VII of the Development Document.

Water Treatment

All water supplies contain varying amounts of suspended solid matter and dissolved chemical salts. Table A-V-2 gives typical characteristics of powerplant water supplies. Salts are dissolved from rock and mineral formations by water as it flows into rivers and lakes. In the boiler, as water evaporates to steam, mineral salts deposit on metal surfaces as scale. Scale reduces transfer of heat through the metal tubes, and if allowed to accumulate reduces the

Table A-V-2

TYPICAL CHARACTERISTICS OF POWERPLANT WATER SUPPLIES

Constituent	Concentration (mg/l)
Calcium, as $CaCO_3$	40 - 200
Magnesium, as $CaCO_3$	10 - 50
M Alkalinity, as $CaCO_3$	5 - 50
Sulfate, as SO_4	20 - 140
Chloride, as Cl	10 - 150
Silica, as SiO_2	2 - 15
Iron, as Fe	0.2 - 2.0
Manganese, as Mn	0.1 - 1.0
Oil	<1 - 5.0
Suspended Solids	10 - 200
pH	5.5 - 7.5
Specific Conductance, µmhos (18°C)	100 - 500

flow area, eventually causing failure of the tubes. To prevent scaling, water is treated for removal of mineral salts before its use as boiler feed water.

Removal of the dissolved mineral salts can be accomplished by evaporation, chemical precipitation or by ion exchange. Evaporation produces a distilled-water-quality product but is not always economical and results in a stream of brine waste. Chemical precipitation is of limited use in the removal of dissolved solids, as the product water of the process contains soluble quantities of mineral salt. To produce a boiler feed water, chemical precipitation followed by evaporation is used occasionally, but cost is not always economical.

Clarification

Chemical precipitates and naturally occurring suspended solids are very fine and light. Clarification is a process of agglomerating the solids and separating them from the water by settling. Suspended solids are coagulated, made to join together into larger, heavier particles and then allowed to settle. Clarified water is drawn off and filtered to remove the last traces of turbidity. Settled solids, more commonly called sludge, are withdrawn from the clarifier basin, continuously or intermittently and discharged to waste. Figures A-V-4 and A-V-5 show simplified flow diagrams for clarification and filtration processes respectively. Surface water, in addition to dissolved impurities, may contain suspended matter, causing turbidity or objectionable color. Removal of turbidity by coagulation is an electro-chemical phenomenon. Iron and aluminum ions of positive charge form a bridge with the negative charge of the sediments, causing an agglomeration of the particles. Most commonly used coagulants are aluminum sulfate (alum, filter alum, $Al_2(SO_4)_3 \cdot 18\ H_2O$), ferrous sulfate (copperas, $FeSO_4 \cdot 2\ H_2O$), ferric sulfate (ferrifloc, $Fe_2(SO_4)_3$), and sodium aluminate (soda alum, $Na_2Al_2O_4$). Polyelectrolytes and other coagulant aids are frequently used in the process.

Softening

In the softening process, chemical precipitation is applied to hardness and alkalinity. Principal chemicals used are calcium hydroxide (hydrated lime - $Ca(OH)_2$) and sodium carbonate (soda ash-Na_2CO_3). Calcium is precipitated as calcium carbonate ($CaCO_3$) and magnesium as magnesium hydroxide ($Mg(OH)_2$).

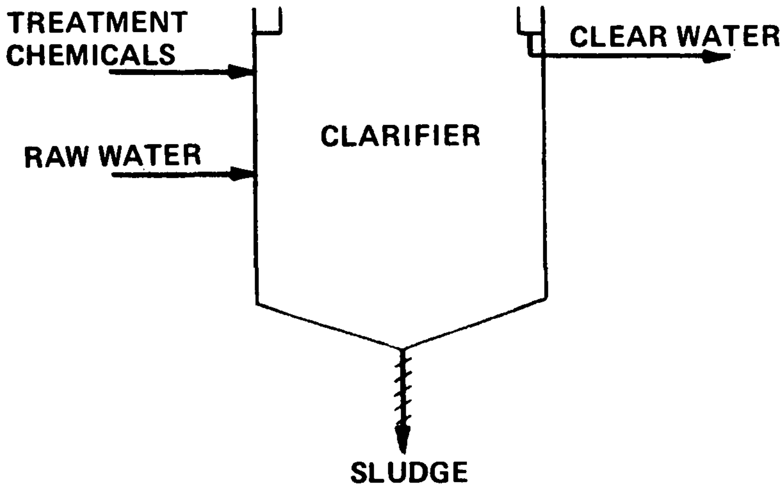


FIGURE A-V-4 CLARIFICATION PROCESS

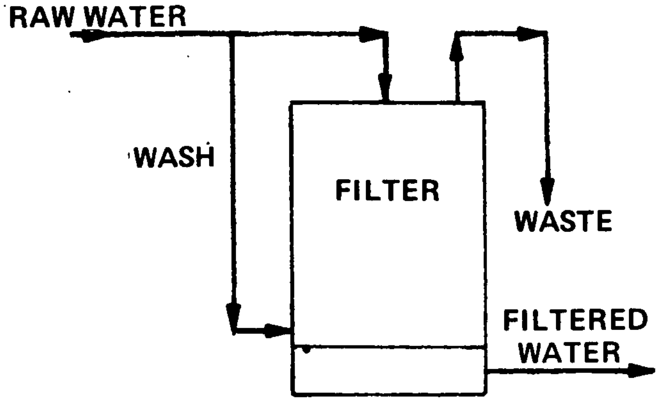


FIGURE A-V-5 FILTRATION PROCESS

Chemical precipitation of calcium and magnesium can be carried out at ambient temperatures, which is known as cold process softening, or may be carried out at elevated temperatures, 100°C (212°F), known as hot process softening. Hot process softening is generally employed for boiler feed water in steam electric powerplants when steam is generated for heating purposes as well as electric power generation. The hot process accelerates the reactions and reduces the solubility of calcium carbonate and magnesium hydroxide.

Since there is always some carryover of fine particles from the clarifiers, these are generally followed by filters. Filters may contain graded sizes of sand, anthracite coal or other filter media. Filters are also required in case clarifiers have an upset and precipitates are carried over into the clear water overflow.

Ion Exchange

Ion exchange processes can be designed to remove all mineral salts in one unit process operation. These processes produce high-quality water suitable for boiler feed purposes. All of the mineral constituents are removed in one process. The ion exchange material is an organic resinous type material manufactured in granular bead form. Resin beads contain pores that make them similiar to a sponge. The surface area is electrically charged and attracts to the surface chemical ions of opposite charge.

Basically there are two major types of resin, cation and anion. Cation resin attracts the positively charged ions and anion resin attracts the negatively charged ions. When the charded sites on the resin surface are filled with ions exchanged from the water, the resin ceases to function and must be regenerated. (Figure A-V-6)

The regeneration process is a three-step operation for all ion exchange units except mixed resin units. Mixed resin units (Figure A-V-7) contain a mixture of cation and anion resin in a single vessel. The resin is in a mixed form during the service run and is separated during the regeneration.

During the service run, water flow in an ion exchanger is generally downflow through the resin bed. This downward flow of water causes a compaction of the bed which in turn causes an increase in resistance to flow through the bed. In addition, the raw water being treated always contains some micro-size particles which collect at the top surface of the bed and add to the resistance to flow. To alleviate

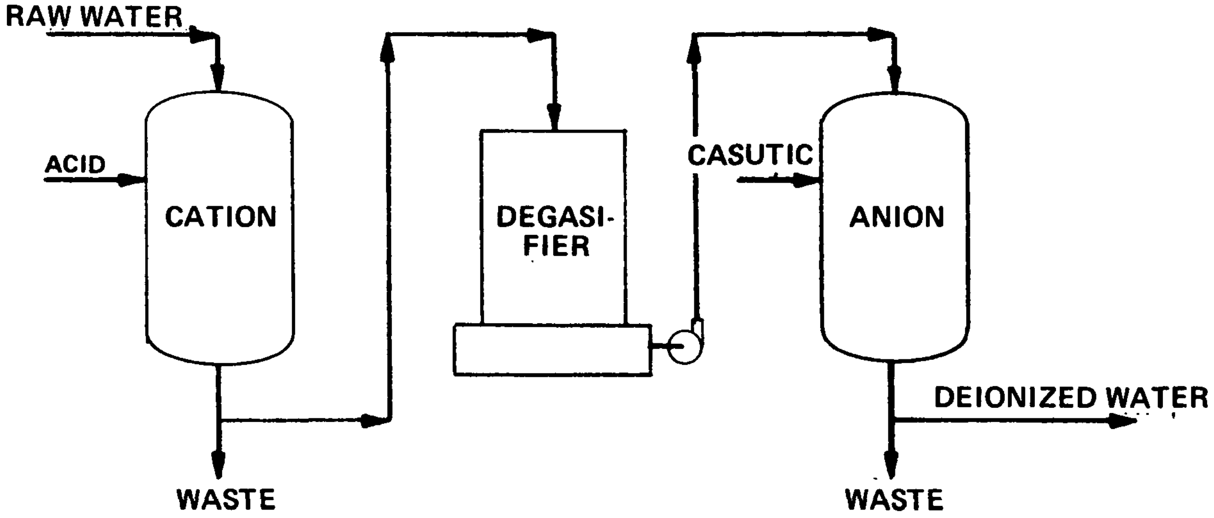


FIGURE A-V-6 ION EXCHANGE PROCESS CATIONIC AND ANIONIC TYPE

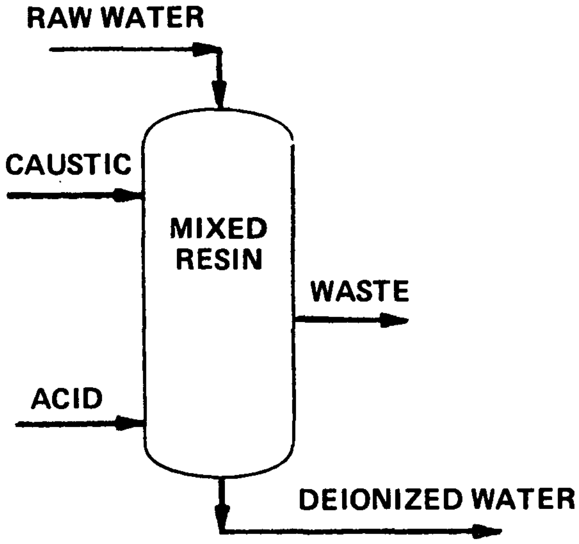


FIGURE A-V-7 ION EXCHANGE PROCESS MIXED RESIN TYPE this resistance, normal water flow to the bed is stopped and direction of flow through the bed is reversed, causing the bed to erupt, and wash the solids out. Ion exchange beds are usually washed for a period of 10 to 15 minutes. Flow rates vary with the size of vessel and the type of resin. The flow rate is adjusted to expand the resin bed 80 to 100% of its settled bed depth. Flow rates of 3.4-4.1 10^{-3} cu m/s/sq m (5-6 gallons per minute per square foot) are typical. The second stage of regeneration is the contacting step. Chemical solution is passed through the bed at a controlled flow rate such that resin is contacted with the chemical solution for a certain time. Cation resins are contacted for approximately 30 minutes while anion resins are contacted for approximately 90 minutes. Immediately after this chemical contact, the bed is given a slow rinse. The normal volume of rinse is two bed volumes. The purpose of the rinse is to wash the regenerant solution remaining in the voids of the bed after the regenerant flow is stopped. The bed is then rinsed until effluent quality reaches deionized water specification. Quantity of rinse water depends on the resin. Cation rinse water is approximately 8 cu m water per cu m resin. Anion rinse water is approximately 10 cu m water per cu m resin. With mixed resin units, there are two additional steps in the regeneration process. After rinsing, the water level is drained until it is just above the settled resin bed level. Air is injected into the bottom of the vessel causing the two stratified layers of resin tc mix. After this mixing, the vessel is filled with water and the resin bed is given a short final rinse.

Chemical characteristic of the spent regenerant depend, on the type of service that an ion-exchanger is performing. Cation exchange in hydrogen cycle absorbs calcium, magnesium, potassium, and sodium ions from the water. The cation unit is regenerated with sulfuric acid. The acid concentration is maintained low to prevent calcium sulfate precipitation. The spent regenerant solution contains the eluted ions with excess acid.

In order for the regeneration process to proceed there must be a driving force. The driving force is excess chemical quantity. The quantity of acid required for regeneration, on a weight basis, is 2-4 times the stoichiometric exchange capacity of the resin. On a weight basis, the waste sulfuric acid will consist of 1/4-1/3 part mixed cations and 2/3-3/4 part of excess sulfuric acid. Concentration of cations in the waste depends on their distribution in the water supply.

Occasionally, hydrochloric acid is used for hydrogen cycle regeneration. Hydrochloric acid yields a greater regeneration efficiency than sulfuric acid. The cost of hydrochloric acid is generally higher than sulfuric acid, therefore, it is used only when the economics justify it.

Anion exchange units are regenerated with sodium hydroxide. The concentration is approximately 4%. The spent regenerant will contain the eluted anions. These are sulfate, chloride, nitrate, phosphate, alkalinity, bicarbonate, carbonate, and hydroxide. Silica in the form of $HSiO_3^-$ is also absorbed by anion exchangers and may be present in the spent regenerant.

In high-pressure steam electric plants, condensate is deionized to prevent dissolved salts from condenser tube leaks from entering the boiler system, and eliminate minute quantities of iron and copper formed as a result of corrosion. The condensate is then polished in mixed resin units. The ion exchange resin is regenerated with sulfuric acid and sodium hydroxide. Sometimes, ammonium hydroxide is used in place of sodium hydroxide. The quantity of iron and copper found in the spent regenerants is usually negligible.

Sodium cycle ion exchange is the exchange of calcium and magnesium ions for sodium ions. Hard water is often softened by this process, but the content of dissolved solids is not appreciably changed. The exchange resin is regenerated with 10% sodium chloride solution. The waste regenerant consists of approximately 1/3 part calcium chloride and magnesium chloride and 2/3 part sodium chloride.

Evaporator

Evaporation is a process of purifying water for boiler feed by vaporizing it with a heat source and then condensing the water vapor on a cool surface, and collecting it externally of the evaporator unit. In the process, a portion of the boiling water is drawn off as blowdown.

The evaporator consists of a vessel, usually in a horizontal position in order to provide a large surface area for boiling. In steam electric plants, evaporators are usually heated by a waste source of heat, such as extraction steam from the turbine cycle. The water evaporates into the upper surface of the vessel and is ducted to an external condenser. In the lower portion of the vessel, a pool of the boiling water is maintained at a constant level to keep the steam tubes immersed in liquid. As water evaporates from the pool, the raw water salts in the pool become concentrated. If allowed to concentrate too much, the salts will scale the heating surfaces and the heat transfer rate diminishes. To prevent scaling, a portion of the pool water is drawn off as blowdown. A simplified flow diagram of the process is shown in Figure A-V-8.

Chemical composition of the blowdown is similar to that of the raw water feed except that it is concentrated several times. The blowdown is alkaline, with a pH in the range of 9-11. This is due to decomposition of bicarbonate ion to carbon dioxide and carbonate ion. The carbon dioxide is degassed from the evaporator leaving carbonate in solution and yielding an alkaline pH. If the concentration of calcium sulfate is high enough, it will precipitate out of solution. Some steam electric power plants feed phosphate to the raw water feed. This phosphate reacts with calcium and lessens the precipitation of calcium carbonate and calcium sulfate.

Evaporators are usually found in older low-pressure steam electric plants. Ultra pure water required in the modern high pressure units may generally be obtained more economically by the ion exchange processes.

A typical powerplant may employ a combination of the different water treatment operations described above. However, the waste streams from all these water treatment operations are generally similar in pollutant characteristics. Consequently, a description of the combined pollutants found in the waste streams is given below.

Character of Water Treatment Wastes

Water treatment waste streams should be described by three parameters: 1) pH, 2) suspended solids concentration, and 3) concentration parameters typical of processes involved or toxic elements involved in the process. Reference 21 reports waste water flows as shown in Table A-V-3.

Clarification wastes consist of clarifier sludge and filter washes. Clarifier sludge could be either alum or iron salt sludge, from coagulant chemicals. If the clarifier is lime softening, then the sludge would be a calcium carbonate-magnesium hydroxide sludge. Filter washes would contain suspended solids either as light carry-over floc from the clarifier or as naturally contained in unclarified raw water. Activated carbon absorber wash would contain light suspended particles or very fine activated carbon particles due to attrition of the carbon.

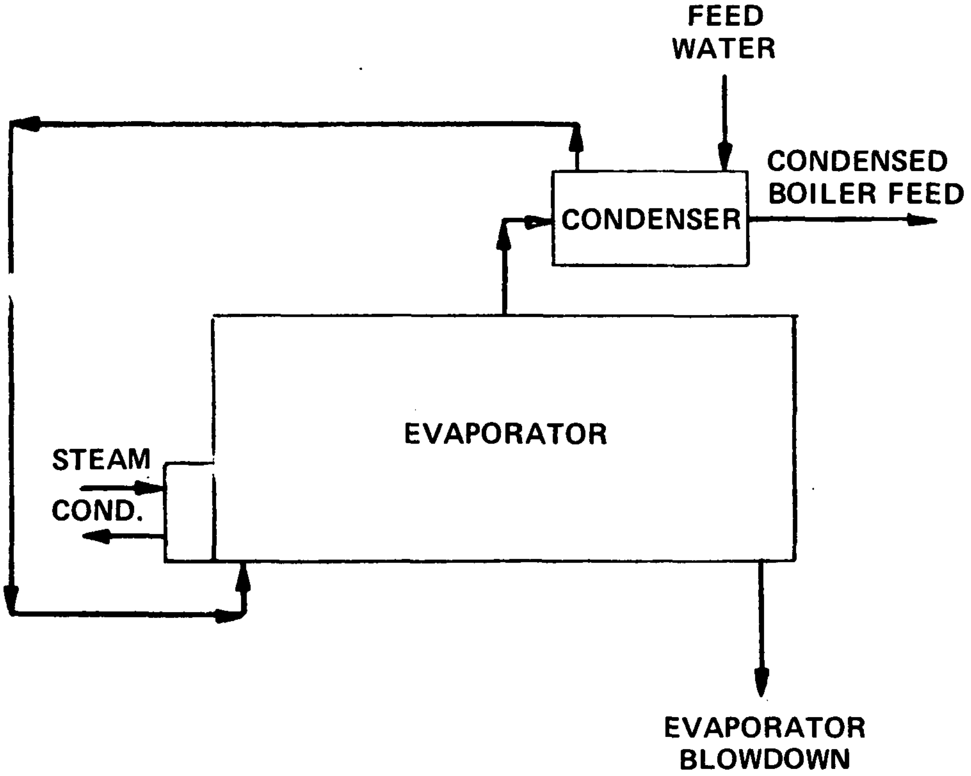


FIGURE A-V-8 EVAPORATION PROCESS

Table A-V- 3

TYPICAL WATER TREATMENT WASTE WATER FLOWS (Ref. 21)

PROCESS	RANGE OF FLOWS gal/ 1000 lb water treated
Clarifier blowdown	1 - 4
Lime-soda	1 - 4
Raw water filtration backwash	0 - 6
Feed water filter	0 - 6
Sodium zeolite regeneration	0.5 - 3
Cation exchange regeneration	0.5 - 3
Anion exchange regeneration	0.5 - 3
Evaporator blowdown	12 -40
Condensate filtration and ion exchange	0.02 - 0.6
Condensate powdex	0.01 - 0.06

Various attempts have been made to classify clarifier sludges. Although these vary from plant to plant, the basic characteristics are quite similar. Alum sludge is a non-Newtonian, bulky gelatinous substance composed of aluminium hydroxide, inorganic-particles, such as clay or sand, color colloids, micro-organisms including plankton and other organic matter removed from water.

The major constituent in sludge from lime soda softening is calcium carbonate. Other consituents which may be present are magnesium hydroxide, hydroxides of aluminum or iron, insoluble matter such as clay, silt or sand, and organic matter such as algae or other plankton removed from the water.

The American Water Works Association Research Foundation has conducted a study among its members to gather information on the nature of waste disposal problems in water treatment plant to assist the utilities. [14]

Waste sludges from clarifiers generally have a solids content in the range of 3,000 - 15,000 mg/l. Suspended solids amount to approximately 75 - 80% of total solids with the quantity of volatile solids being 20 - 25% of total solids. The BOD level usually is 30 - 100 mg/l. A large corresponding COD level of 500 - 10,000 mg/l shows that the sludge is not biodegradable, but that it is readily oxidizable. The sludge has a pH of about 5 - 9.

Filter backwash is more dilute than the wastes from clarifiers. Generally, it is not a large volume of waste. Turbidity of wash water is usually less than 5 mg per liter and the COD is about 160 mg per liter. The total solids existing in filter backwash from plants producing an alum sludge is about 400 mg per liter with only 40 - 100 mg/l suspended solids.

All ion exchange wastes are either acidic or alkaline except sodium chloride solutions which are neutral. While ion exchange wastes do not naturally have any significant amount of suspended solids, certain chemicals such as calcium sulfate and calcium carbonate have extremely low solubilities and are often precipitated because of common ion effects. Calcium sulfate precipitation is common in ion exchange systems because of excess quantities of sulfuric acid.

Evaporator blowdown consists of concentrated salts from the feed water. Evaporators are usually operated to a point where the blowdown is three to five times the concentration of the feed water. Due to the low solubility of calcium carbonate and calcium sulfate, it is possible that there will be precipitation of calcium carbonate and sulfate, if present in the feed water. While the concentrated salts of the feed water are neutral, decomposition of bicarbonate to carbon dioxide and calcium carbonate, creates an alkaline waste stream from the evaporator.

Table A-V-4 shows the arithemetic mean and standard deviation for a number of parameters for water treatment wastes. These data were gathered from many different sources and reported in various ways. Therefore they show wide variations. As can be seen, the standard deviation of each parameter chosen, is two to three times greater than the mean value of the parameter.

Undoubtedly, other factors that do not appear in the data caused this variation. Under the sub-heading of clarification wastes, the reported data do not indicate whether the waste stream is a sludge from a clarifier removing suspended solids, a sludge from a lime softener for hard water, or a wash-water from a filter. Obviously, waste stream composition will vary depending upon its origin.

Similarly, data listed under ion-exchange wastes do not indicate whether the waste is acid, caustic or brine waste. There are no indicators of what source the waste originated from, or if the waste was neutralized before reporting. In summary, data collected on water treating wastes is of limited value because of the process variations which were not reported, and because of the limited quantity of information available on these waste streams.

Boiler or PWR Steam Generator Blowdown

Except for zero solid treatment systems, no external water treatment regardless how efficient, is in itself protection against boiler scale without the use of supplementary internal chemical treatment of the boiler water.

The primary cause of scale formation is that the solubilities of scale forming salts decrease with an increase in temperature. The higher the temperature and pressure of boiler operation, the more insoluble the scale forming salts become. No method of external chemical treatment operates at a temperature as high as that of the boiler water. Consequently, when the boiler feed water is heated to the boiler operating temperatures, the solubility of the scale forming salts is exceeded and they crystallize from solution as scale on the boiler heating surfaces.

TABLE A-V-4

ARITHMETIC MEAN AND DEVIATION OF SELECTED WATER TREATMENT WASTE PARAMETERS

	ARITHMETIC MEAN m	STANDARD DEVIATION 0-	0-/m
CLARIFICATION WASTES			
Flow - M^3 per day	316	613	1.9
Turbidity - J.T.U.	1,088	2,015	1.8
Total Suspended Solids - mg TSS per l	25,213	53,060	2.1
Total Suspended Solids - kg TSS per day	2,673	5,594	2.1
Total Hardness - mg $CaCO_3$ per l	3,215	7,812	2.4
Total Hardness - kg $CaCO_3$ per day	27	63	2.3
Iron - mg Fe per l	352	572	1.6
Iron - kg Fe per day	212	662	3.1
Aluminum	1 Piece	Data	-
ION EXCHANGE WASTE			
Flow - M^3 per day	74,515	374,737	5.0
Total Dissolved Solids - mg TDS per l	7,408	11,550	1.6
Total Dissolved Solids - kg TDS per day	1,311	4,263	3.2
Sulfate - mg SO_4 per l	2,085	3,859	1.8
Sulfate - kg SO_4 per day	1,100	3,414	3.1
Chloride - mg Cl per l	1,708	4,603	2.7
Chloride - kg Cl per day	124	389	3.1
Sodium - mg Na per l	3,112	6,448	2.1
Sodium - kg Na per day	558	1,572	2.8
Ammonia - mg NH_3 - N per l	46	137	3.0
Ammonia - kg NH_3 - N per day	14	41	2.9
EVAPORATOR BLOWDOWN			
Flow - M^3 per day	38	62	1.6
Total Dissolved Solids - mg TDS per l	730	805	1.1
Total Dissolved Solids - kg TDS per day	88	187	2.1
Total Suspended Solids - mg TSS per l	175	443	2.5
Total Suspended Solids - kg TSS per day	16	36	2.2
Sulfate - mg SO_4 per l	79	109	1.4
Sulfate - kg SO_4 per day	4	8	2.0
Chloride - mg Cl per l	194	337	1.7
Chloride - kg Cl per day	17	31	1.8

Calcium and magnesium salts are the most common source of difficulty with boiler scale. Internal chemical treatment is required to prevent deposit scale formation from the residual hardness concentration remaining in the feed water. One of the most common sources of scale is the decomposition by heat of calcium bicarbonate to calcium carbonate and carbon dioxide.

$$Ca(HCO_3)_2 + Heat = CaCO_3(s) + H_2O + CO_2(g)$$

Deposits of iron oxide, metalic copper and copper oxide are frequently found in boilers operating with very pure feedwater. The source of deposits is corrosion. Causes of the corrosive action are dissolved oxygen and carbon dioxide.

To prevent calcium and magnesium salts from scaling on boiler evaporative surfaces, internal treatment consists of precipitating the calcium and magnesium salts as a sludge and maintaining the sludge in a fluid form so that it may be removed by boiler blowdown. The blowdown can be continuous or intermittent and the operation involves controlled discharge of a certain quantity of boiler water. The most common chemicals used for precipitation of calcium salts are the sodium phosphates.

Chelating or complexing agents are sometimes applied. Tetrasodium salt of ethylenediaminetetracetic acid (Na_4-EDTA) and trisodium salt of nitrilotriacetic acid (Na_3-NTA) are the most commonly used chelating agents. The chelating agents complex the calcium, magnesium, iron and copper in exchange for the sodium.

The solubility of iron in water increases as the pH decreases below the neutral point. To prevent corrosion, neutralization of the acid with an alkali is necessary. Sodium carbonate, sodium hydroxide and/or ammonia are commonly employed for this purpose.

Dissolved oxygen present in boiler water causes corrosion of metallic surfaces. Dissolved oxygen is introduced into the boiler, not only by the makeup water, but by air infiltration in the condensate system. In addition to mechanical deaeration, sodium sulfite is employed for chemical deaeration.

$$2\ Na_2SO_3 + O_2 = 2Na_2SO_4$$

It is common practice to maintain an excess of the sulfite to assure complete oxygen removal. The use of sodium sulfite is restricted to low pressure boilers because the reaction products are sulfate and dissolved solids which are undesirable in high pressure boilers.

Hydrazine is a reducing agent which does not possess these disadvantages for high pressure operation. Hydrazine reacts with oxygen to form water.

$$N_2H_4 + O_2 = 2H_2O + N_2$$

The excess hydrazine is decomposed by heat to ammonia and nitrogen.

The characteristics of boiler blowdown are an alkaline waste with pH from 9.5-10.0 for boilers treated with hydrazine and pH from 10-11 for boilers treated with phosphates.

Blowdown from medium pressure boiler has a total dissolved solids (TDS) in the range of 100-500 mg/1. High-pressure boiler blowdown has a total dissolved solids in the range of 10-100 mg/1. Blowdown from boiler plants using phosphate treatment contain 5-50 mg/1 phosphate and 10-100 mg/1 hydroxide alkalinity. Boiler plants with hydrazine treatment produce a blowdown containing 0-2 mg/l ammonia.

In PWR nuclear-fueled powerplants, the steam generator employs ultrafine quality water. Consequently the blowdown frequency and the impurities are much less than that in fossil fuel plants.

The blowdown frequency is commonly once a day. Most of the data also confirm the typical alkaline nature of the blowdown. The data do not show completely the type of treatment and the raw water treatment efficiency. Consequently, the data have greatly varying parameters. Reference 21 reports waste water flows from boiler blowdown ranging from 0-4 gal/1000 lb steam generated.

Equipment Cleaning

Chemical Cleaning Boiler or PWR Steam Generator Tubes

Boilers are subject to two major chemical problems, corrosion and scale formation. Proper operation and maintenance involves the pretreatment of boiler makeup water, and the addition of various corrosion and scale control additives to the feed water. Boilers operating at high pressures (and temperatures) require more critical control of boiler water chemistry than low pressure boilers.

Even with the best preventive maintenance, occasional boiler cleaning is a necessary operation for proper performance of steam boilers. Condenser leaks, oxygen leaks in the boiler water and corrosion/erosion of metallic parts by boiler water may increase the frequency of boiler cleanings.

The data in Table A-V-5 shows pollutant concentrations for specific cases. Inasmuch as boiler cleaning is tailored for individual requirements, generalization about pollutant concentration is not possible. However, the data does indicate generally observed high amounts of metallic species and COD requirements.

In this study, boiler tube cleaning was not categorized on the basis of once-through or drum-type. However, it is to be noted that similar cleaning as described earlier is followed for once-through type boilers.

In nuclear powerplants of the PWR type, strict control on the quality of steam generator water is maintained. Cleaning frequently varies with plant characteristics, as in fossil-fuel power plants, but the cleaning methods are the same.

Chemical cleaning of boilers can be of two types - 1) Preoperational--necessary for new boilers before going onstream and 2) Operational-necessary for scale and corrosion products removal to maintain normal boiler operating performance.

Preoperational Boiler Cleaning Wastes

During the manufacture and assembly of boiler steel components, a black iron oxide scale (mill scale) is formed on metal surfaces. The removal of mill scale is necessary to eliminate potential galvanic corrosion and erosion of turbine blades which can occur because of trapped mill scale in the steam path. Similarly, the presence of oil, grease (used during fabrication and assembly) and construction debris can be detrimental to boilers. Consequently, preoperational cleaning of boilers is an important aspect of powerplant start-up procedures.

Typical steps for preoperational cleaning involve:

(i) an alkaline boilout using a solution containing caustic or soda ash, phosphates, wetting or emulsifying agents and sodium nitrite as an inhibitor to protect against caustic embrittlement.

TABLE A-V-5

CHEMICAL WASTE CHARACTERIZATION

INCREASE IN POLLUTANT QUANTITY PER CLEANING CYCLE

BOILER TUBES' CLEANING

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
Plant Code	Cleaning Frequency	Boiler Volume		Alkalinity (CaCO3)		BOD		COD		Total Solids		Total Dissolved Solids		Total Suspended Solids		Ammonia	
	months	m3	(1000 gal.)	(lb)	Kg	(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg
3409	24	174	46	1380	626	104	47.2	4017	1823	11816	5369	8588	3899	176	80	16.7	7.58
3409	24	174	46	1380	626	104	47.2	4017	1823	11816	5369	8588	3899	176	80	16.7	7.58
3410	12	106	28	181	82	-9.8	-4.45	5091	2311	12024	5458	10684	4850	9.8	4.45	1.2	0.54
3412	24	215	57	-158	-72	-8.3	-3.8	8302	3769	11972	5435	11225	5096	75	34	9.8	4.45
3414	12	303	80	3770	1711.9	121.4	55	11101	5040	34817	15807	1983	900.4	505.2	229.4	52.86	24.0
3416		190	50	158.4	71.94	-1.65	-0.75	9169	4163	39698	18023	37196	16887	246	111.7	3.2	1.454
3404		571	150.8	-23.8	-10.84	0	0	-14.07	-6.39	99.34	45.1	99.34	45.1	0	0	0	0
3603	22	314.58	83.09	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3603	23	117.1	30.93	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3604	15		43.165	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3604	20		43.165	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3604	13	278.8	92.92	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3604	7	163.4	35.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3604	20	163.4	35.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3605	50	261.19	69.18	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3605	60	261.19	69.18	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3605	50	261.19	69.18	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3605	12	143.45	37.89	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3605	24	143.45	37.89	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3605	24	189.3	50.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3606	36	183.1	48.37	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3606	22	183.1	48.37	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3609	48	108.95	28.78	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3609	100	108.95	28.78	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3609	74	108.95	28.78	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3607	15	148.903	39.33	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3610	12	136.18	35.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3610	9	136.18	35.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3610	18	136.18	35.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3610	15	136.18	35.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3611	50	129.6	34.23	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3611	100	129.6	34.23	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3612	60	52.65	13.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3612	30	52.65	13.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3612	50	52.65	13.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3612	40	52.65	13.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3612	24	77.17	20.38	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3612	30	77.17	20.38	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3612	36	77.17	20.38	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3612	40	77.17	20.38	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3612	40	137.54	36.33	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3612	30	137.54	36.33	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3614	40	59.9	15.82	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3614	24	74.4	19.66	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3614	20	74.4	19.66	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3614	36	74.4	19.66	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3614	14	74.4	19.66	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3614	12	74.4	19.66	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3613	30	74.9	19.78	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3613	24	74.9	19.78	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3613	24	74.9	19.78	-	-	-	-	-	-	-	-	-	-	-	-	-	-

TABLE A-V-5

CHEMICAL WASTE CHARACTERIZATION

INCREASE IN POLLUTANT QUADTITY PER CLEANING CYCLE

BOILER TUBES' CLEANING (continued)

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	
Plant Code	Nickel		Zinc		Sodium		Nitrate		Hardness		Bromide		Manganese		Turbidity	Acidity, Oil and Grease, Mercury, Sulfite, Lead, Selenium, Phenols, Surfactants
	(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg	JTU	
3409	95.8	43.5	5.99	2.72	1076	488	0.56	0.25	1·11	550	-	-	-	-	370	NO DATA
3409	95.8	43.5	5.99	2.72	1076	488	0.56	0.25	1:11	550	-	-	-	-	370	
3410	-	-	10.3	4.67	2018	916	-5.6	-2.54	-	-	-	-	-	-	276	
3412	--	--	-0.045	-0.02	-	-	-0.542	-0.25	-29.19	-13.25	-	-	-	-	23	
3414	294	133.88	169.6	77	4885	2218	2.9	1.32	89.86	40.8	-	-	-	-	387	
3416	108.4	49.22	91.56	41.57	12378	5620	0.817	0.371	-	-	-	-	-	-	100	
3404	-	-	0.00018	0.00008	-55.9	-25.46	-	-	1.25	0.57	-	-	0.0059	0.0027	0	
3603	111	50.4	141	64	-	-	-	-	-	-	-	-	30.8	14	-	
3603	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
3604	-	-	-	-	2569	1166	-	-	-	-	484	219.7	-	-	-	
3604	-	-	-	-	2569	1166	-	-	-	-	484	219.7	-	-	-	
3604	100	45.4	126	57.2	3504	1590	-	-	-	-	492	223	27.9	12.7	-	
3604	-	-	-	-	1902	863	-	-	-	-	582	264	-	-	-	
3604	-	-	-	-	2742	1244	-	-	-	-	484	219.7	-	-	-	
3605	81.9	37.2	106	48.1	3363	1526	-	-	-	-	-	-	48.9	22.2	-	
3605	-	-	-	-	3363	1526	-	-	-	-	-	-	-	-	-	
3605	-	-	-	-	5007	2273	-	-	-	-	-	-	-	-	-	
3605	-	-	-	-	2200	998	-	-	-	-	503	228	-	-	-	
3605	-	-	-	-	1515	687	-	-	-	-	503	228	-	-	-	
3605	-	-	-	-	2031	922	-	-	-	-	773	350.9	-	-	-	
3606	577	262	74.89	34	182	82	-	-	-	-	635	288	15.4	7	-	
3606	-	-	-	-	243	110.3	-	-	-	-	847	384	-	-	-	
3609	33	15	44	20	128	58	-	-	-	-	444	201	11	5	-	
3609	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
3609	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
3607	46.2	21	59.4	27	-	-	-	-	-	-	-	-	13.2	6	-	
3610	-	-	-	-	2603	1181	-	-	-	-	476	216	-	-	-	
3610	-	-	-	-	1301	590.6	-	-	-	-	635	288	-	-	-	
3610	44	20	55	25	2603	1244	-	-	-	-	476	216	11	5	-	
3610	-	-	-	-	-	-	-	-	-	-	476	216	-	-	-	
3611	41.8	19	52.8	24	3500	1589	-	-	-	-	465	211	11	5	-	
3611	-	-	-	-	5374	2441	-	-	-	-	465	211	-	-	-	
3612	-	-	-	-	1144	519	-	-	-	-	481	218	-	-	-	
3612	-	-	-	-	573	260	-	-	-	-	243	110	-	-	-	
3612	-	-	-	-	1144	519	-	-	-	-	481	218	-	-	-	
3612	-	-	-	-	573	260	-	-	-	-	243	110	-	-	-	
3612	-	-	-	-	3027	1374	-	-	-	-	270	122	-	-	-	
3612	-	-	-	-	3027	1374	-	-	-	-	270	122	-	-	-	
3612	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
3612	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
3612	44.0	20	55	25	-	-	-	-	-	-	-	-	11	5	-	
3612	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
3614	-	-	-	-	201	91.4	-	-	-	-	698	317	-	-	-	
3614	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
3614	-	-	-	-	55.7	25.28	-	-	-	-	193	87.6	-	-	-	
3614	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
3614	24.23	11	30.8	14	1440	653	-	-	-	-	-	-	6.6	3	-	
3614	-	-	-	-	2161	981	-	-	-	-	-	-	-	-	-	
3613	24.23	11	30.8	14	2105	955	-	-	-	-	201	91.2	6.6	3	-	
3613	-	-	-	-	810	367	-	-	-	-	328	148.9	-	-	-	
3613	-	-	-	-	2105	955	-	-	-	-	201	91.2	-	-	-	

TABLE A-V- 5

CHEMICAL WASTE CHARACTERIZATION

INCREASE IN POLLUTANT QUANTITY PER CLEANING CYCLE

BOILER TUBES' CLEANING (continued)

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
Plant Code	Phosphorus		Sulfate		Chloride		Fluoride		Aluminum		Chromium		Copper		Iron		Magnesium	
	(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg
3409	4.07	1.84	11.26	5.11	7772	3528	-	-	-	-	6.91	3.13	251.6	114.2	599	271.9	224	101.7
3408	4.07	1.84	11.26	5.11	7772	3528	-	-	-	-	6.91	3.13	251.6	114.2	599	271.9	224	101.7
3410	0.4	0.18	-40	-18.6	19100	8671	-	-	-	-	1.4	0.63	245.5	111.4	1571	713.2	-	-
3412	-0.08	-0.036	-	-	6142	2788	-	-	-	-	1.21	0.55	-	-	1668	757.2	-	-
3414	7.26	3.3	73.37	33.31	25898	11758	-	-	-	-	23.17	10.52	718	326	1841	836	13.83	6.28
3416	-0.001674	-0.00076	0.33	0.15	32191	14615	-	-	-	-	0.0832	0.0378	325	147.7	5491	2493	-	-
3404	-0.0125	-0.0057	2.24	1.02	6.03	2.74	-	-	-	-	0.035	0.0160	0.00006	0.00003	0.001	0.00045	-	-
3603	74	33.6	-	-	40361	18324	870	395	18.94	8.6	-	-	800	363	3100	1407	66	29.9
3603	-	-	-	-	15052	6834	-	-	-	-	-	-	800	363	3100	1407	-	-
3604	-	-	-	-	21006	9537	478	217	-	-	-	-	900	408.6	2400	1089	-	-
3604	-	-	-	-	21006	9537	478	217	-	-	-	-	800	363	4900	2224	-	-
3604	78.9	35.82	-	-	45224	20532	2509	1139	17	7.7	16.9	7.7	500	227	3800	1725	59.0	26.8
3604	-	-	-	-	14588	6623	514.7	233	-	-	-	-	300	136.2	2200	999	-	-
3604	-	-	-	-	14588	6623	514.7	233	-	-	-	-	600	272	2100	953	-	-
3605	58.72	26.66	-	-	42085	19107	3837	1742	13.87	6.3	13.87	6.3	200	90.8	4000	1816	48.9	22.2
3605	-	-	-	-	38290	17834	3837	1742	-	-	-	-	100	45.4	3000	1362	-	-
3605	-	-	-	-	42085	19107	3837	1742	-	-	-	-	25	11.35	3000	1362	-	-
3605	-	-	-	-	18440	8372	1050	477	-	-	-	-	500	227	1100	499	-	-
3605	-	-	-	-	18440	8372	1050	477	-	-	-	-	600	272	1100	499	-	-
3605	-	-	-	-	24332	11047	1385	628	-	-	-	-	600	272	5000	2270	-	-
3606	40.97	18.6	-	-	29422	13358	-	-	11.0	5	11.01	5	200	90.8	3500	1816	33	15
3606	-	-	-	-	29422	13358	-	-	-	-	-	-	300	136.2	4500	2043	-	-
3609	24.45	11.1	-	-	13167	5978	1596	724	28.6	13	6.6	3	400	181.6	1500	681	22	10
3609	-	-	-	-	13167	5978	-	-	-	-	-	-	200	90.8	2500	1135	-	-
3609	-	-	-	-	13167	5978	399	181	-	-	-	-	300	136.2	3000	1362	-	-
3607	33.76	15.33	-	-	19140	8690	-	-	8.8	4	8.8	4	300	136.2	3000	1362	28.6	13
3610	-	-	-	-	14588	6623	514.7	233.6	-	-	-	-	500	227	100	45.4	-	-
3610	-	-	-	-	17506	7948	997	452.6	-	-	-	-	400	181.6	1000	454	-	-
3610	30.1	13.7	-	-	14588	6623	514.7	233.6	8.8	4	-	-	500	227	1000	454	26.43	12
3610	-	-	-	-	14588	6623	514.7	233.6	-	-	-	-	500	227	900	408	-	-
3611	28.7	13.05	-	-	19477	8843	864.5	392.4	6.6	3	6.6	3	600	272	2000	908	24.23	11
3611	-	-	-	-	16696	7580	864.5	392.4	-	-	-	-	400	181.6	2500	1135	-	-
3612	-	-	-	-	6768	3073	192.8	87.53	-	-	-	-	200	90.8	900	408	-	-
3612	-	-	-	-	8460	3841	192.8	87.53	-	-	-	-	100	45.4	800	363	-	-
3612	-	-	-	-	6768	3073	192.8	87.53	-	-	-	-	200	90.8	700	318	-	-
3612	-	-	-	-	8460	3841	192.8	87.53	-	-	-	--	300	136.2	500	227	-	-
3612	-	-	-	-	8266	3753	282	128	-	-	-	-	300	136.2	1000	454	-	-
3612	-	-	-	-	8266	3753	282	128	-	-	-	-	400	181.6	1000	454	-	-
3612	-	-	-	-	12398	5629	1130	513	-	-	-	-	100	45.4	1500	681	-	-
3612	-	-	-	-	11572	5254	1130	513	-	-	-	-	100	45.4	1000	454	-	-
3612	30.9	14.03	-	-	17101	7764	504	228.8	8.8	4	8.8	4	300	136.2	3000	1362	26.43	12
3612	-	-	-	-	14733	6689	504	228.8	-	-	-	-	200	90.8	1500	681	-	-
3614	-	-	-	-	9625	4370	253	114.86	-	-	-	-	500	227	1600	726	-	-
3614	-	-	-	-	11962	5431	1092	495	-	-	-	-	100	45.4	1400	635	-	-
3614	-	-	-	-	9568	4344	546	247.88	-	-	-	-	100	45.4	1200	545	-	-
3614	-	-	-	-	11962	5431	546	247.88	-	-	-	-	100	45.4	1000	454	-	-
3614	17.24	7.83	-	-	11962	5431	552	250.6	4.4	2	13.2	6	50	22.7	1000	454	13.22	6
3614	-	-	-	-	11962	5431	829	376.3	-	-	-	-	50	22.7	500	227	-	-
3613	17.24	7.83	-	-	8022	3642	549	249.2	4.4	2	4.4	2	200	90.8	1000	454	13.22	6
3613	-	-	-	-	8022	3642	362.3	164.5	-	-	-	-	200	90.8	1000	454	-	-
3613	-	-	-	-	8022	3642	275	124.8	-	-	-	-	200	90.8	1000	454	-	-

TABLE A-V-16

CHEMICAL WASTE CHARACTERIZATION

INCREASE IN POLLUTANT QUANTITY PER CLEANING CYCLE

AIR PREHEATER CLEANING

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
Line	Plant Code	Cleaning Frequency	Batch Volume		Alkalinity		COD		Total Solids		Total Dissolved Solids		Total Suspended Solids		Sulfate		Chloride	
		cycles/yr	m^3	(1000 gal.)	(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg
1)	3409	12	409	108	-72.02	-32.7	14.4	6.54	11951	5426	7907	3590	1975	897	1066	484	1.801	0.8178
2)	3410	12	852	225	-76.65	-34.8	16.87	7.66	24964	11334	16605	7539	4008	1820	2231	1013	0	0
3)	3411	8	1363	360	-90.08	-40.9	14.98	6.8	40528	18400	27022	12268	6603	2998	3601	1635	0	0
4)	3412	12	2272	600	-530.39	-240.8	35.02	15.9	65515	29744	44264	20096	10788	4898	6114	2776	9989	4534
5)	3413	5	265	70	189.73	86.14	116.7	53	2616	1188	4467	2028	477.9	217	692	314.2	0	0
6)	3414	6	162.8	43	-19.71	-8.95	5.72	2.6	4768	2165	3189	1448	785.24	356.5	423.8	192.4	-8.96	-4.07
7)	3415	4	378.6	100	-25.02	-11.36	9.16	4.16	11257	5111	8249	3745	1834	833	979	444.5	-14.16	-6.43
BOILER FIRESIDE CLEANING																		
8)	3410	2	2626	720	-240	-109	1134	515	40861	18551	35127	15948	3823	1736	11949	5425	0	0
9)	3411	8	90.8	24	5.99	-2.72	19	8.63	4002	1817	3002	1363	119.09	54.07	299.4	135.9	18.01	8.18

AIR PREHEATER CLEANING (continued)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
Line	Plant Code	Ammonia		Nitrate		Phosphorus		Hardness		Chromium		Copper		Iron		Magnesium		Nickel	
		(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg	(lb)	kg
1)	3409	2.378	1.08	3.414	1.55	0.513	0.233	3949	1793	1.1[illegible]	0.529	4.434	2.018	1531	695.1	874.45	397	67.55	30.67
2)	3410	4.49	2.04	5.06	2.3	2.66	1.21	8255	3748	24.25	11.01	-	-	3189	1448	1850	840	140.72	63.89
3)	3411	8.1	3.68	11.25	5.11	4.67	2.12	13372	6071	39.03	17.72	-	-	5103	2317	2986	1356	225	102.2
4)	3412	12	5.45	5.48	2.49	5.86	2.66	22196	10077	59.19	26.875	0	0	8506	3862	4812	2185	375.3	170.38
5)	3413	0.722	0.328	0.471	0.214	0.035	0.016	476.8	216.5	0.749	0.34	2.907	1.32	3.495	1.587	107.4	48.76	28.63	13
6)	3414	0.925	0.42	1.074	0.488	0.559	0.254	1577	716	0.458	0.208	1.788	0.812	2.13	0.967	352.4	160	17.93	8.14
7)	3415	2.176	0.988	3.37	1.53	1.32	0.6	3709	1684	0.533	0.242	1.86	0.848	2.379	1.08	828	376	20.83	9.46
BOILER FIRESIDE CLEANING (continued)																			
8)	3410	1.49	0.68	14.75	6.7	11.1	5.04	35409	16076	0.0299	0.0136	-	-	900	408.9	11949	5425	30.02	13.63
9)	3411	0.039	0.018	0.7	0.318	0.257	0.117	791.41	359.3	0.998	0.453	0.249	0.113	30	13.63	190.35	86.42	-	-

AIR PREHEATER CLEANING (continued)

	A	B	C	D	E	F	G	H
Line	Plant Code	Sodium		Zinc		BOD		Turbidity
		(lb)	kg	(lb)	kg	(lb)	kg	JTU
1)	3409	1.799	0.818	4.43	2.011	3.6	1.635	495
2)	3410	0	0	8.97	4.075	0	0	476
3)	3411	0	0	14.93	6.78	0	0	497
4)	3412	8630	3918	25.02	11.36	15.01	6.815	478
5)	3413	552	251	0.283	0.1285	2.335	1.06	500
6)	3414	-0.35	-0.16	1.788	0.812	1.793	0.814	500
7)	3415	1.66	0.757	2.07	0.942	1.668	0.757	498
BOILER FIRESIDE CLEANING (continued)								
8)	3410	0	0	28.72	13.042	0	0	476
9)	3411	9	4.09	2	0.908	0	0	98

(ii) draining of the solution after achieving satisfactory removal of oil, grease, silica, loose scale, dirt and construction debris etc.

(iii) rinsing of the boiler

(iv) acid cleaning of the boiler to remove mill scale using corrosion inhibited hydrochloric acid or organic acids, such as citric and formic acids or patented chelating scale removers.

(v) draining of the acid solution using nitrogen to prevent metal rusting

(vi) second rinsing of the boiler with demineralized water

(vii) an alkaline boilout to neutralize trapped acid and to remove trapped hydrogen gas molecules (which if left in the boiler can cause metal embrittlement over a period of time)

(viii) and finally followed by a passivation rinse using sodium nitrite and phosphate solution.

These typical preoperational cleaning steps are followed for drum type boilers. For once-through boilers, process steps are similar except that instead of boilout, continuous flushing is carried out.

The pollution parameters associated with preoperational boiler cleanings are extreme pH values (acidic or alkaline solutions), phosphates,. nitrates, BOD from the organic emulsifying agents, oil and grease and suspended solids. The quantity of these wastes and the pollutant concentrations vary for each specific case.

Reference 468 describes the preoperational chemical cleaning program for a nuclear powerplant.

Operational Boiler Cleaning Wastes

A variety of cleaning formulations are used to chemically clean boilers whose operation has deteriorated due to build up of scale and corrosion products. Analyses of scale deposits are made on sample sections of tubes cut from the boiler. Based on the composition of scale discovered in these samples, a cleaning program is selected. Some procedures are more effective for copper removal, others for iron removal, and still others for silica removal. The composition of boiler scale and corrosion products is briefly described. This is followed by a description of methods used to renovate boilers.

Composition of Scale

Boiler scale contains precipitated salts and corrosion products. Precipitation occurs because of local supersaturation of their solution concentration near the heated tube surfaces. These salts include calcium carbonate and sulfate, calcium and magnesium phosphates and silicates, and magnesium hydroxide as principal constituents. Iron and copper oxides are present as corrosion byproducts and various trace metals as zinc, nickel, aluminum may be present either as constituents of the feed water, or as corrosion products. In addition, mud, silt, dirt or other debris introduced via condenser leaks are also present. Oil contamination of boiler water results in carbonation of this waste and this is incorporated into the boiler scale. The composition of boiler scale is dependent on the composition of boiler feed water, materials of construction, boiler chemical additives, and contaminants leaked into the boiler water, and therefore will differ with each successive cleaning of the boiler.

Frequency of Boiler Cleanings

There are many factors which affect the cleaning schedule for power utility steam boilers. High pressure boilers require more critical control of feed water purity and consequently usually require less frequent cleanings. A review of boiler cleaning data in Table A-V-5 shows that cleaning frequency varies from once in seven months to once in one hundred months. The mean time between boiler cleanings is estimated from these data as thirty months with a standard deviation of eighteen months.

Reference 469, prepared by the ASME Research Committee Task Force on Boiler Feedwater Studies, is a report of an investigation of current practices regarding factors influencing the need (frequency) for chemical cleaning of boilers.

Types of Boiler Tube Cleaning Processes

Alkaline Cleaning Mixtures with Oxidizing Agents for Copper Removal

These formulations may contain free ammonia and ammonium salts, (sulfate or carbonate), an oxidizing agent such as potassium or sodium bromate or chlorate, or ammonium persulfate, nitrates or nitrites, and sometimes caustic soda. Air is sometimes used as the oxidant. These mixtures clean by the following mechanism: Oxidizing agents convert metallic copper deposits to copper oxide. Ammonia reacts with the copper oxide to solubilize it as the copper ammonium blue complex.

Since metallic copper interferes with the conventional acid cleaning process described below, this cleaning formulation is frequently used to precede acid cleaning when high copper levels are present in the boiler scale.

The pollutants introduced by these cleaning formulations are as follows: ammonium ion, oxidizing agents, high alkalinity, and high levels of iron and copper ion dissolved from the boiler scale.

Acid Cleaning Mixtures

These mixtures are usually based on inhibited hydrochloric acid as solvent, although sulfuric, sulfamic, phosphoric, nitric, citric, formic and hydroxyacetic acids are also used. Hydrofluoric acid or fluoride salts are added for silica removal. Corrosion inhibitors, wetting agents, and complexing agents to solubilize copper may also be included.

These mixtures are effective in removal of scale due to water hardness, iron oxides, and copper oxide, but not metallic copper.

The principal pollutants introduced to the waste stream from these cleaning chemicals are acidity, phosphates, fluorides, and organic compounds (BOD). In addition large quantities of copper, iron, hardness, phosphates and turbidity are released as a result of loosening and dissolving the boiler scale.

Alkaline Chelating Rinses and Alkaline Passivating Rinses

These formulations contain ammonia, caustic soda or soda ash, EDTA, NTA, citrates, gluconates, or other chelating agents, and may contain certain phosphates, chromates, nitrates or nitrites as corrosion inhibitors. These cleaning mixtures may be used alone, or after acid cleaning to neutralize residual acidity and to remove additional amounts of iron, copper, alkaline earth scale compounds, and silica. Their use introduces the following pollutants to the discharged wastes: alkalinity, organic compounds (BOD), phosphates, and scale components such as iron, copper and hardness.

Methods Using Organic Solvents

Organic solvents are also widely used to remove iron/copper scales from boiler tubes. Two common methods, described in Reference 444, are:

1. Vertan 675(R) (Dow trademark). This is an ammoniated salt of ethylenediaminetetraacetic acid. In this process the boiler is first protected by injecting a corrosion inhibitor, then sufficient Verton 675 or EDTA is pumped in to achieve a 5-10% solution. The boiler is then fired to 75-100 psi (about 300-325°F) until the iron has been picked up, the boiler is cooled to 200°F, the chelant strength is restored to about 5% and air is introduced into the unit. This oxidizes the copper to the cupric form which is readily complexed. The boiler is drained, rinsed and is made ready for service. The pH of this solvent is about 9.5.

2. Citrosolv Process. This is another two-step process. It starts with a 3% citric acid solution ammoniated to a pH of 3.5. The solution is circulated at a temperature of 200°F for 6-8 hours or until all of the iron has been picked up. The second step calls for raising the pH to 9.2 - 9.5 by addition of anhydrous or aqueous ammonia after cooling the boiler to 150°F. Air is then injected to oxidize the copper and finally sodium nitrite is injected to assist in rendering passive surfaces. A final demineralized water or condensate rinse completes the job.

Proprietary Processes

Frequently boiler tubes are cleaned by specialized companies using proprietary processes and cleaning chemicals. Most of these chemicals are similar to those described earlier and the resulting wastes contain: alkalinity, organic compounds (BOD), phosphate, ammonium compounds, and scale compounds such as iron, copper and hardness.

Condenser Cleaning

The other major heat transfer component in a boiler system is the condenser. The spent steam from the turbine is liquefied in the condenser by the condenser cooling water system. Condenser tubes are made out of stainless steel, titanium or copper alloys. Preoperational cleaning of the condensers is done with alkaline solutions, with emphasis on the steam side of the condenser because of high quality water circulation. Operational cleaning on the steam side depends upon boiler water quality and is not done frequently. The water side of the condenser is cleaned with inhibited hydrochloric acid.

Boiler Fireside Cleaning

The fireside of boiler tubes collects fuel ash, corrosion products and airborne dust. Gas-fired boilers have the cleanest combustion process.

In order to maintain an efficient heat transfer, boiler firesides are cleaned with high pressure fire hoses, while the boilers are hot. Soda ash or other alkaline materials may be used to enhance the cleaning. Depending upon the sulfur content of the fuel, the cleaning wastes are more or less acid.

Data was available from only two plants for boiler fireside cleaning. These data are shown in Table A-V-6. The pollutants in the waste stream may reveal extreme values of pH, hardness and suspended solids as well as some metals.

Air Preheater Cleaning

Air preheaters are an integral part of the steam generating system. They are used to preheat the ambient air required for combustion and thus economize thermal energy. Two types of preheaters are used -- tubular or regenerative. In either case, part of the sensible heat of the combustion flue gases is transferred to the incoming fresh air.

In tubular air preheaters, cold fresh air is forced through a heat exchanger tube bundle using a forced-draft-fan. The flue gases leaving the economizer flow around the tubes and heat is transferred through the metal interface. Regenerative type preheaters are used more frequently in large powerplants. In this type, heat is regenerated by using metallic elements in a rotor. The rotor revolves between two ducts -- outlet duct carrying hot flue gases to the stack and intake duct carrying fresh air to the boiler windbox. Heat is transferred to the metallic elements which in turn transfer it to the fresh air by convection.

Soot and fly ash accumulate on the preheater surfaces and the deposits must be removed periodically to maintain good heat transfer rates as well as to avoid plugging of the tubes or metallic elements. Preheaters are cleaned by hosing them down with high-pressure water from fire hoses.

Depending upon the sulfur content of the fuel, the cleaning wastes are more or less acidic in nature. The washing fluid may contain soda ash and phosphates or detergents which have been added to neutralize excess acidity or alkaline depending on the cleaning product used. Fly ash and soot, rust, magnesium salts, and metallic ions leached from the ash and soot are normal constituents of the cleaning wastes. Copper, iron, nickel, and chromium are usually prevalent in this discharge, and in oil-fired installations vanadium may also be present at significant levels.

Cleaning frequency is usually about once a month, but frequencies of 4 to 180 cleanings per year are reported in Table A-V-5.

Chemical data for air preheater cleaning are also shown in Table A-V-5. Data for plant number 3412 appears to deviate considerably from the other plants, and much of the data reported varies considerably from other plants, by as much as an order of magnitude.

Feedwater Heaters Cleaning

According to Reference 444, the number of closed feedwater heaters in the preboiler cycle ranges from 4 to 10. Tubes may be formed from admiralty brass; 90/10, 80/20, 70/30 cupro-nickel; monel and arsenical copper in the nonferrous group and carbon steel and stainless steel in the ferrous family. Tube sizes are 5/8" or 3/4" O.D. by 15 to 80 feet long. They may be straight or hairpin bent tubes. Feedwater flows through the tubes, extracting heat from the steam which surrounds the tubes.

Pre-operationally both sides of the heaters may be cleaned to remove oils, grease, dirt and preservative coatings put on by the manufacturer. The cleaning solvent is generally a solution of 0.0% to 1.0% tri-sodium phosphate containing wetting agents. Recirculation at 180°F is maintained for 6-12 hours. Draining and rinsing with demineralized water completes the job. In some cases the water side of the heaters are also acid cleaned using an organic acid such as 3% solution of citric, ammoniated citric or hydroxyacetic-formic acids at 190°F. Sometimes these jobs are done simultaneously with the cleaning of the boiler. Again there is a reluctance to acid clean the steam side of the heater for fear of acid "hanging up" in crevices.

Operational cleaning in general has not been required on the ferrous alloy tubes. Deposits found on the water side of the copper alloy tubing have been predominantly copper and iron oxides. The common solvent used has been 5-20% hydrochloric acid, circulated for 6-8 hours at a temperature of 150°F. Neutralization of the system has been accomplished by circulating a 0.5 - 1.0% soda ash or caustic soda solution for 2-3 hours at 120-150°F. Rinsing with demineralized water completes the cleaning process.

Miscellaneous Small Equipment Cleaning

At infrequent intervals, other plant components such as condensate coolers, hydrogen coolers, air compressor coolers, stator oil coolers, etc. are cleaned chemically. Inhibited hydrochloric acid is a common chemical used for cleaning. Detergents and wetting agents are also added when necessary. The waste volume is, of course, smaller than that encountered in other type of chemical cleanings. Pollutant parameters are low-high pH, total suspended solids (TSS) metallic components, oil, etc.

Stack Cleaning

Depending upon the fossil fuel used, the stack may have deposits of fly ash, and soot. Acidity in these deposits can be imparted by the sulfur oxides in the flue gases. If a wet scrubber is used to clean the flue gas, process or equipment upsets can result in additional scaling on the stack interior. Normally, high-pressure water is used to clean the deposits on stack walls. These wastes may contain total suspended solids (TSS), high or low pH values, metallic species, oil, etc.

Cooling Tower Basin Cleaning

Depending upon the quality of the make-up water used in the cooling tower, carbonates can be deposited in the tower basin. Similarly, depending upon the inefficiency of chlorine dosages, some algae growth may occur on basin walls. Some debris carried in the atmosphere may also collect in the basin. Consequently, periodic basin washings with water is carried out. The waste water primarily contains total suspended solids (TSS) as a pollutant.

Ash Handling

Steam-electric powerplants which utilize oil or coal as a fuel produce ash as a waste product of combustion. The total ash is of two sorts: bottom ash and fly ash. Bottom ash is the residue which accumulates in the furnace bottom, and fly ash is the material which is carried over in the flue gas stream.

Ash-handling or transport is the conveyance of the accumulated waste products to a disposal system. The method of conveyance may be either wet (sluicing) or dry (pneumatic). This section discusses the wet ash handling system and in particular, the waste water which it produces.

The chemical characteristics of ash handling waste water is basically a function of the fuel burned. The following table from Reference 278 lists commercial fuels for power production.

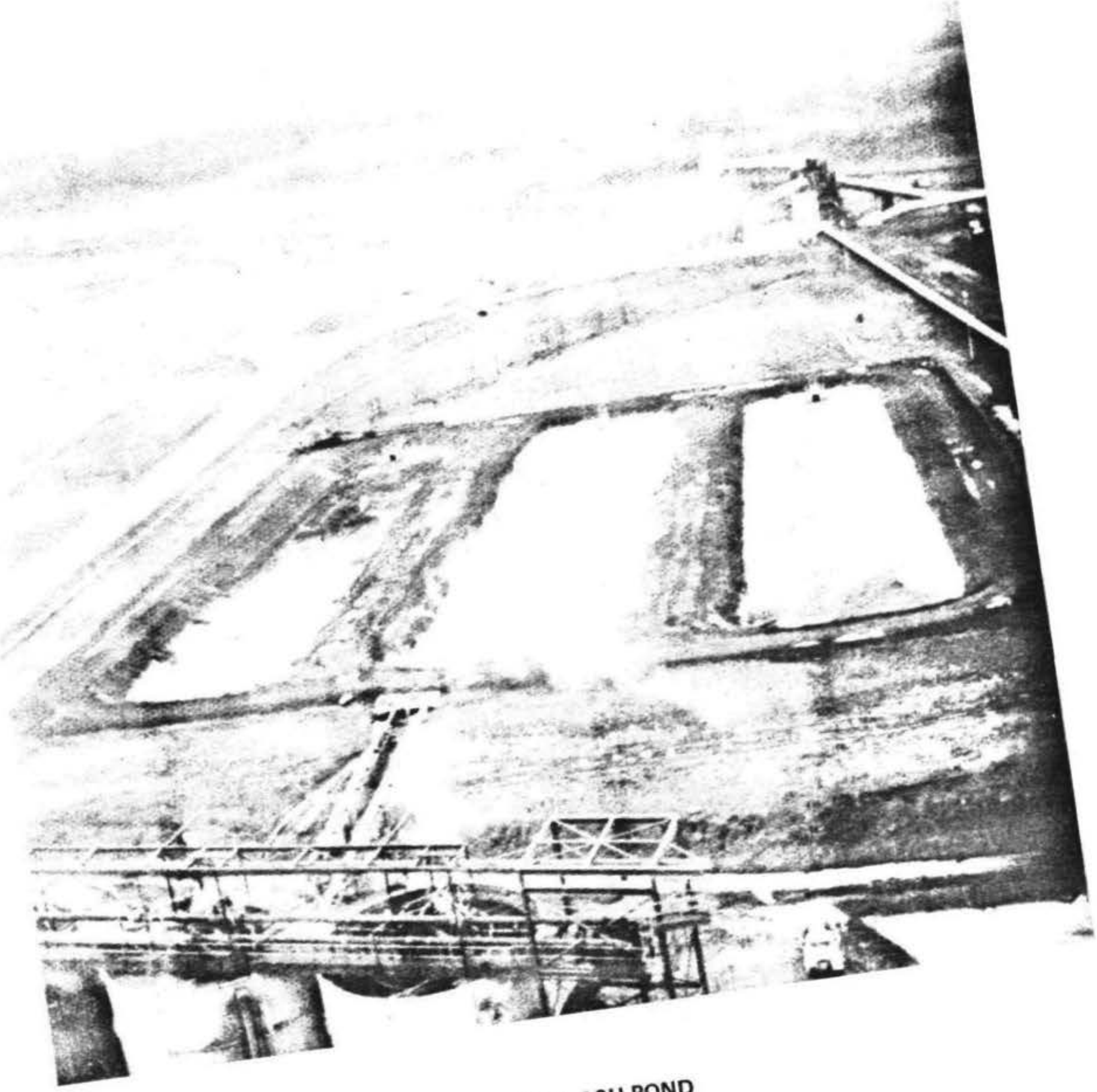
Fuels Containing Ash	Fuels Containing Little or No Ash
All coals	Natural gas
Fuel oil-"Bunker C"	Manufactured gas
Refinery sludge	Coke-oven gas (clean)
Tank residues	Refinery gas
Refinery Coke	Distillates (most)
Most tars	Combustion-turbine exhaust
Wood and wood products	
Other products of vegetable	
Waste-heat gases (most)	
Blast-furnace gas	
Cement-kiln gases	

Of the fuels containing ash, coals and fuel oil are mostly used in the power industry.

Coal

Coal is the most widely used fossil fuel in United Stated powerplants. In 1972, 335 million tons of coal were consumed in the U.S. for power generation. The average ash content of coal is 11% for the nation,[238] with a range from 6 to 20%. It may, therefore be estimated that roughly 37,000,000 tons of ash were produced in 1972 by U.S. powerplants. Disposal of this quantity of solids from the waste water stream has prompted most utilities to install some sedimentation facility. In many cases, ash settling ponds are used. A typical ash pond is illustrated in Figure A-V-9, which is located in plant no. 4217. However, in some cases, because of unavailability of land, aesthetics, or some other reason, utilities have installed more sophisticated materials-handling systems based on the sedimentation process.

The characteristics of the water handling coal ash is related to the physico-chemical properties of that ash and to



TYPICAL ASH POND
PLANT NO. 4217
Figure A-V-9

the volume and initial quality of the water used. Table A-V-7 lists some of the constituents of coal ash.[238] Table A-V-8 shows the volume and time variabilities of water flow in an ash handling system. Reference 21 reports that water requirements for ash handling are as follows:

- fly ash 1,200-40,000 gal/ton ash conveyed
- bottom ash 2,400-40,000 gal/ton ash conveyed

Data obtained from discharge permit applications on ash pond overflows for 33 plants burning coal indicates a wide range in the overflow quantities, from about 0.2 MGD per 1000 Mw of generating capacity to about 50 MGD per 1000 Mw of capacity. The data, as MGD per 1000 Mw, approximate a log-normal distribution, with 50 percent of the ash pond overflows being less than 5 MGD per 1000 Mw and 60 percent less than 10 MGD per 1000 Mw. Based on the annual coal consumption reported for these plants (Ref.: Steam Electric Plant Factors/1971), the overflows range from about 0.1 MGD per million tons coal burned per year to about 16 MGD per million tons coal burned per year, with a median value of about 4 MGD per million tons coal burned per year.

The relative percentages of bottom ash and fly ash depend upon the mode of firing and the type of combustion chamber. Following figures are satisfactory averages, for a coal of 13,000 Btu/lb.

Type of operation	Fly ash (% of total ash)
Pulverized coal burners	
Dry bottom, regardless of type of burner	85
Wet bottom (without fly ash reinjection)	65
Cyclone furnaces	20
Spreader stokers (without fly ash reinjection)	65

The number of variables involved in characterizing the water used for ash handling is such that it is not probable that any two plants would exhibit the same waste stream characteristics. The approach taken in this report is to examine a cross section of plant data. There are no data available on the actual ash sluicing waste water. However, since most plants now employ a settling pond, the ash pond overflow data can be used to evaluate associated waste water characteristics. These data are summarized in Table A-V-9.

Table A-V- 7

CONSTITUENTS OF COAL ASH [238]

Constituent	Percent
SiO_2	30-50
Al_2O_3	20-30
Fe_2O_3	10-30
TiO_2	0.4-1.3
CaO	1.5-4.7
MgO	0.5-1.1
Na_2O	0.4 1.5
K_2O	1.0-3.0
SO_3	0.2-3.2
C and volatiles	0.1-4.0
P	0.1-0.3
B	0.1-0.6
U and Th	0.0-0.1
Cu	trace
Mn	trace
Ni	trace
Pb	trace
Zn	trace
Sr	trace
Ba	trace
Zr	trace

Table A-V- 8

TIME OF FLOW FOR ASH HANDLING SYSTEMS

Plant No. 0110, a 952 Mw unit fueled by pulverized coal

- basis is one 8-hr cycle -

Duty	Flow Rate, gpm	Duration, minutes
H. E. #1	1,960	73
Flushing	600	15
H. E. #2	1,960	60
Flushing	600	20
H. E. #3	1,960	47
Flushing	600	15
Purge	1,960	3 x 8 each
Fill	1,500	3 x 15 each
Pyrites Tank	2,660	12
Purge	2,660	8
Grider Seal	8	180
Mill Rejects	515	7 x 6 each
Pressure Transfer	1	210
Hydrovac*	4,604	270
Bubblers	4	continuous
Cool Weirs	540	continuous
Pyrites Tank Make-up	640	12

*NOTE: Only significant item pertaining to fly ash handling. All other items pertain to bottom ash handling.

TABLE A-V- 9

CHEMICAL WASTE CHARACTERIZATION

ASH POND OVERFLOW - NET DISCHARGE

CHANGE IN PARAMETER LEVEL FROM INTAKE TO DISCHARGE

Plant Code	Plant Capacity		Fuel	Flow		Total Solids					Total Dissolved Solids					Total Suspended Solids				
	MW	MWHr/day	C - Coal O - Oil	m^3/day	(1000gpd)	mg/l	(lb/day)	kg/day	(lb/MWHr)	kg/MWHr	mg/l	(lb/day)	kg/day	(lb/MWHr)	kg/MWHr	mg/l	(lb/day)	kg/day	(lb/MWHr) x 10^6	kg/MWHr x 10^6
3412	1114.5	13205	C/O	19574	5170	3560	153490	69688	11.62	5.272	3328	143495	65147	10.87	4.929	91	3923	1781	297100	134800
3416	740	10525	C	13100	3460	-23	-663	-301	-0.064	-0.0292	-110	-3174	-1441	-0.308	-0.14	40	1154	524	112066	50878
3404	300	5420	C/O	2556	675	1879	10577	4802	1.952	0.886	1852	10423	4732	1.92	0.873	27	152	69	28044	12732
3402	308	4965	C/O	2726	720	54	324	147	0.065	0.0296	40	240.2	109.04	0.483	0.219	14	84.05	38.16	16931	7687
3401	31	865	C	9132	2412	-1338	-26914	-12219	-31.1	-14.12	-1309	-26323	-11951	-30.41	-13.81	1	20.11	9.13	2323	1055
3405	116.2	1629	C/O	18.17	4.8	-18509	-745	-338	-0.457	-0.207	-18520	-741.41	-336.6	-0.455	-0.206	11	0.44	0.20	270	123
1703	766	6288	C	22716	6000	-240	-12008	-5452	-1.91	-0.867	-129	-6453	-2930	-1.026	-0.465	-111	-5552	-2521	-89867	-40800
1720	1178	16155	C	49218	13000	362	39247	17818	2.423	1.1	330	35777	16243	2.12	1	32	3469	1575	213656	97000
1710	1162	3164	C/O	2726	720	0	0	0	0	0	108	648.45	294.4	0.2048	0.093	0	0	0	0	0
1722	1232	15563	C	98436	26000	112	24284	11025	1.54	0.7	106	22984	10435	1.475	0.67	-1	-216.7	-98.4	-13920	-6320
1709	690	0706	O	3786	1000	309	2574.9	1169	0.295	0.134	328	2735	12417	0.3127	0.142	-13	-108.3	-49.2	-12445	-5650
1711				32560	8600	509	36506	16574	1.652	0.075	486	34856	15825	1.586	0.72	23	1647	748	75110	34100
1711				2650	700	506	2954	1341	0.135	0.061	499	2912	1322	0.133	0.06	7	40.86	18.55	1868	848
*1711	1179	21872	C	35210	9300		39460	17915	1.787	0.0811		37768	17147	1.719	0.78		1687.86	766.55	76978	34948
3936				3786	1000	387	3227	1465	0.169	0.077	447	2892	1313	0.153	0.069	17	141.76	64.36	7467	3390
3936				22716	6000	680	34026	15448	1.799	0.816	650	32524	14766	1.719	0.78	94	4702	2135	248678	112900
*3936	1086	18908	C	26502	7000		37253	16913	1.968	0.893		35416	16079	1.873	0.85		4843.76	2199.36	256145	116290
3927	1469	21705	C	5300	1400	647	7552	3429	0.345	0.157	620	7237	3286	0.3326	0.151	17	198.45	90.1	9141	4150
2616	933	14276	C	15901	4200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1808	732	12050	C	15144	4000	121	4035	1832	0.334	0.152	364	12143	5513	1.006	0.457	-243	-8105	-3680	-671800	-305000
1729	186	2978	C	1817	480	670	2680	1217	0.9	0.408	646	2586	1174	0.868	0.394	51	203.96	92.6	68491	31095
1718	1042	13856	C/O	53000	14000	79	9222	4187	0.665	0.302	75	8755	3975	0.632	0.287	1	116.74	53	8266	3753
3930				15144	4000	1124	37491	17021	9.82	4.46	1059	35328	16039	9.25	4.2	65	2167.4	984	567841	257800
3930				3786	1000	1084	9013	4092	2.356	1.07	1081	9013	4092	2.356	1.07	3	25	11.35	6555	2976
*3930	500	3816	C	18930	5000		46504	21213	12.176	5.53		44341	20131	11.606	5.27		2192.4	995.35	574396	260776
1825				37103	9800	626	51163	23228	2.06	0.936	611	49934	22670	2	0.91	15	1224.67	556	49339	22400
1825				12115	3200	525	14011	6361	0.564	0.256	435	11608	5270	0.467	0.212	85	2268	1030	91418	41504
1825				6058	1600	500	6669	3028	0.268	0.122	460	6136	2786	0.247	0.112	35	4669	212	18819	8544
1825				114	30	1000	250.2	113.6	0.01	0.0045	500	125.11	56.8	.00504	0.00229	100	25.02	11.36	1008	458
*1825	1304	24813	C	55390	14630		72093	32730	2.9031	1.319		67803	30782	2.72	1.237		8186	1809	160584	72906
3920	544	7695	C	27259	7200	300	18614	8451	2.41	1.098	-320	-18614	-8451	-2.398	-1.098	-4	-300	-136.3	-39017	-17714
1816	600	10149	C	3786	1000	1290	10757	4884	1.06	0.481	1210	10090	4581	0.994	0.4513	36	300	136.3	29581	13430
2608	510	7550	C	5679	1500	230	2876	1306	0.362	0.164	225	2812	1277	0.354	0.1607	5	62.53	28.39	7868	3572
0111	1300	18169	C	27782	7338	295.5	18084	8210	0.9953	0.4518	-	-	-	-	-	-	-	-	-	-
4704	823	9874	C	15434	4076	-1	- 34	- 15	-.0034	-.0016	-	-	-	-	-	-	-	-	-	-
2119				40694	10748	475	42578	19330	1.3535	.6145	-	-	-	-	-	-	-	-	-	-
2119				82252	21725	61	11052	5017	.3513	.1595	-	-	-	-	-	-	-	-	-	-
*2119	2558	31458	C	122946	32473		53630	24347	1.7048	0.7740		-	-	-	-		-	-	-	-
0107	568	5741	C	2726	720	182	1093	496.16	0.1904	0.0864	193	1159	526	0.2019	0.0917	-11	-66.05	-29.98	-11504	-5223
3514	2152	11315	C	10865	2870	-	-	-	-	-	844	20201	9171	1.785	0.8098	-337	-8066	-17767	-712900	-323400
1716				1893	500	414	1724.7	783	.1553	.0705	445	1854	842	.1672	.0759	-7	-29.07	-13.2	-2621	-1190
1716				568	150	324	405.32	184.01	.0365	.0166	277	346.52	157.32	.0312	.0142	69	86.319	39.188	7782	3533
*1716	676	11092	C	2461	650		2129.39	967	0.1928	0.0871		2200	999	0.1984	0.0891		57.25	26	5161	2343

*total of more than one waste stream for plant

TABLE A-V-9

CHEMICAL WASTE CHARACTERIZATION

ASH POND OVERFLOW - NET DISCHARGE (continued)

CHANGE IN PARAMETER LEVEL FROM INTAKE TO DISCHARGE

Plant Code	Total Hardness ($CaCO_3$)					Sulfate					Aluminum					Chromium				
	mg/l	(lb/day)	kg/day	(lb/MWHr) x 10^6	kg/MWHr x 10^6	mg/l	(lb/day)	kg/day	(lb,MWHr) x 10^6	kg/MWHr x 10^6	mg/l	(lb/day)	kg/day	(lb/MWHr) x 10^6	kg/MWHr x 10^6	mg/l	(lb/day)	kg/day	(lb/MWHr) x 10^6	kg/MWHr x 10^6
3412	736	31733	14407	2403000	1090000	152	6554	2973	496300	225100	0.075	3.233	1.468	244	111	-0.113	-4.86	-2.21	-368	-167
3416	25	1010	458.5	98057	44518	2.2	63.48	28.82	6163	2798	-	-	-	-	-	0	0	0	0	0
3404	-	-	-	-	-	120	675.5	306.68	124378	56468	-	-	-	-	-	-	-	-	-	-
3402	-12	-72.04	-32.71	-14513	-6589	8	48.01	21.8	9676	4393	-	-	-	-	-	0.01	0.059	0.027	11	5
3401	-	-	-	-	-	-240	-4826	-2191	-5570000	-2530000	-	-	-	-	-	-	-	-	-	-
3405	-252	-10.04	-4.56	-6165	-2799	-996	-42.5	-19.3	-26165	-11879	-	-	-	-	-	0.139	0.0055	0.0025	3.407	1.547
1703	-	-	-	-	-	45	2251	1022	357929	162500	-	-	-	-	-	0.00001	0.0005	0.00023	0.079	0.036
1720	99	10731	4872	662995	301000	-18	-1951	-886	-120704	-54800	0.011	1.19	0.541	72.68	33	-0.014	-1.515	-0.688	-92.5	-42
1710	-	-	-	-	-	43	258.19	117.22	81497	37000	-	-	-	-	-	-	-	-	-	-
1722	255	55293	25103	3.546x10^6	1610000	63	13658	6201	876651	398000	0.15	32.51	14.76	2070	940	-	-	-	-	-
1709	357	2975	1351	341409	155000	34	258.37	117.3	29515	13400	0.1	0.722	0.378	94.71	43	-	-	-	-	-
1711	220	15777	7163	720264	327000	286	20513	9313	936123	425000	0	0	0	0	0	0	0	0	0	0
1711	110	642	291.55	29361	13330	-26	-151.78	-68.91	-6940	-3151	-0.145	-0.8326	-0.384	-39.6	-18	-0.03	-0.174	-0.079	-8.8	-4
*1711		16419	7454	749625	340330		20665	9244	929183	421849		-0.8326	-0.384	-39.6	-18		-0.17	-0.079	-8.8	-4
3936	207	1724	783	90969	41300	158	1317	598	69603	31600	-	-	-	-	-	0.0005	0.0044	0.0019	0.218	0.099
3936	335	16762	7610	886249	402357	201	10057	4566	531749	241414	-	-	-	-	-	0.007	0.35	0.159	17.6	8
*3936		18486	8393	977218	443657		11374	5164	601352	273014	-	-	-	-	-		0.354	0.1609	17.81	8.099
3927	275	3209	1457	147577	67000	60	700	318	32158	14600	0.153	1.784	0.81	81.49	37	0.011	0.1277	0.058	5.88	2.67
2616	-	-	-	-	-	123	4308	1956	301762	137000	1.67	58.48	26.55	4097	1860	-	-	-	-	-
1808	-	-	-	-	-	128	4268	1938	352420	160000	-	-	-	-	-	-	-	-	-	-
1729	388	1552	705	521445	236736	527	2109	957.5	708205	321525	-	-	-	-	-	-	-	-	-	-
1718	51	5953	2703	429687	195078	98	11440	5194	825674	374856	1.350	157.62	71.56	11376	5165	0.001	0.116	0.053	8.81	4
3930	340	11341	5149	2970000	1349000	220	7339	3332	1922907	873000	0.021	0.7	0.318	182.82	83	-	-	-	-	-
3930	350	2918	1325	764860	347248	300	2501	1135.8	655599	297642	0.021	0.175	0.0795	46.25	21	-	-	-	-	-
*3930		14259	6474	3735000	1696000		9840	4467.8	2578506	1070642		0.875	0.3975	229.07	104		-	-	-	-
1825	406	33182	15065	1320000	600000	180	14709	6678	592511	269000	-	-	-	-	-	0.080	6.54	2.97	262	119
1825	250	6671	3029	268881	122072	225	60044	2726	241993	109865	-	-	-	-	-	0.004	0.105	0.048	4.4	2
1825	200	2668	1211.5	107541	48824	314	4189	1902	168841	76654	-	-	-	-	-	0.007	0.092	0.042	4.4	2
1825	270	67.55	30.67	2722	1236	132	33.01	14.99	1330	604	-	-	-	-	-	0.005	0.001251	0.000568	0.005	0.023
*1825		42588	19336	1699000	772132		78975	11321	1004675	456123		-	-	-	-		6.738	3.06	270.85	123.03
3920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1816	-	-	-	-	-	200	1667	757	164097	74500	6	50	22.72	4912	2230	-	-	-	-	-
2608	0	0	0	0	0	28	350.22	159	44057	20002	-	-	-	-	-	-	-	-	-	-
0111	283	17319	7863	953233	432768	93	5691.5	2584	313253	142217	-	-	-	-	-	-	-	-	-	-
4704	-134.8	-4582	-2078	-464000	-210500	61.5	2090.6	949	211730	96125	-	-	-	-	-	-	-	-	-	-
2119	272.3	24408	11081	775892	352255	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2119	31.3	5671	2574	180278	81846	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
*2119		30079	13655	956170	434101	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
0107	-	-	-	-	-	129.9	840.07	381.1	146328	66433	5.30	32.12	14.58	5597	2541	0	0	0	0	0
3514	-	-	-	-	-	446	10675	4846	943400	428300	-	-	-	-	-	-	-	-	-	-
1716	83	346	157.1	31057	14100	230	959	435.4	86343	39200	-0.22	-0.916	-0.4160	-81.49	-37	-	-	-	-	-
1716	74	92.57	42.02	8346	3789	-49	-61.3	-27.83	-5526	-2509	0.1	0.125	0.0568	11	5	-	-	-	-	-
*1716		438	199	39403	17889		897.3	407.6	80817	36691	-0.12	-0.791	-0.3592	-70.49	-28		-	-	-	-

*total of more than one waste stream for plant

TABLE A-V- 9

CHEMICAL WASTE CHARACTERIZATION

ASH POND OVERFLOW - NET DISCHARGE -(continued)

CHANGE IN PARAMETER LEVEL FROM INTAKE TO DISCHARGE

Plant Code	Sodium					Alkalinity (CaCO$_3$)					Ammonia (N)					Nitrate (N)				
	mg/l	(lb/day)	kg/day	(lb/MWHr) x 10^6	kg/MWHr x 10^6	mg/l	(lb/day)	kg/day	(lb/MWHr) x 10^6	kg/MWHr x 10^6	mg/l	(lb/day)	kg/day	(lb/MWHr) x 10^6	kg/MWHr x 10^6	mg/l	(lb/day)	kg/day	(lb/MWHr) x 10^6	kg/MWHr x 10^6
3412	0	0	0	0	0	-19	-819.2	-371.6	-62000	-28100		-	-	-	-	-	-	-	-	-
3416	-4	-115.4	-52.4	-11204	-5087	-6	-173.1	-78.6	-16808	-7631	-0.03	-0.859	-0.39	-83.39	-37.86	-	-	-	-	-
3404	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3402	-	-	-	-	-	160	960	436	193508	87853	-2.4	-14.4	-6.54	-2903	-1318	0.24	1.44	.65	290	132
3401	52	1046	56.07	1209000	548500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3405	-1609	-63.43	-28.8	-38940	-17679	-	-	-	-	-	0.66	0.026	0.012	16.21	7.36	-0.33	-0.01	-0.005	-6	-3
1703	-	-	-	-	-	-110	-5504	-2499	-875110	-397300	-3	-150	-68.1	-23852	-10829	-0.73	-36.52	-16.58	-5806	-2636
1720	982	106467	48336	6.58x10^6	2.99x10^6	10	1084	492.2	66960	30400	-5	-541	-246	-33480	-15200	0.12	13	5.9	804	365
1710	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1722	26	5638	2560	361233	164000	2	433.7	196.9	27753	12600	0.1	21.67	9.84	13.92	6.32	1.3	282	128	18061	8200
1709	-	-	-	-	-	7	58.37	26.5	6696	3040	-5	-41.69	-18.93	-4790	-2175	0.04	0.33	0.15	37.45	17
1711	-3	-215.63	-97.9	-9845	-4470	-67	-4804	-2181	-218061	-99000	0	0	0	0	0	1.0	71.7	32.560	3260	1480
1711	173	1008	458	46176	20964	64	373	169.6	17083	7756	-4.5	-	-	-	-	0.16	1.51	0.689	70.48	32
*1711		793	361	36331	16494		-4431	-2010.4	-200978	-91244	-	-	-	-	-		73.21	33.249	3330	1512
3936	30	250.22	113.60	13200	6000	13	108.37	49.20	5726	2600	0.83	6.91	3.14	365.68	166	0.8	6.87	3.12	361	164
3936	32	1601	726.98	84656	38434	13	650.50	295.33	34392	15614	1.01	50.52	22.94	2671	1213	0.6	30.02	13.63	1588	721
*3936		1851.22	840.58	97856	44434		758.87	344.53	40118	18214		57.43	26.08	3036	1379		36.89	16.75	1949	885
3927	73	852.4	387	39207	17800	69	805.5	365.7	37004	16800	0.51	5.94	2.7	273.12	124	0.33	3.85	1.75	176.2	80
2616	14	489	222	34350	15595	-67	-2345	-1065	-162995	-74000	0	0	0	0	0	0	0	0	0	0
1808	-	-	-	-	-	28	934	424	77312	35100	0.38	12.68	5.75	1000	500	0.72	24	10.9	1982	900
1729	-	-	-	-	-	-94	-376.2	-170.8	-126330	-57354	0.12	0.48	0.218	160.8	73	1.19	4.75	2.16	1597	725
1718	3	350.2	159	25275	11475	-15	-1751	-795	-126378	-57376	-0.04	-4.67	-2.12	-337	-153	0.09	10.5	4.77	757	344
3930	92	3068	1393	803964	365000	120	4002	1817	1048458	476000	3.4	113.43	51.5	29713	13490	4.2	140	63.6	36696	16660
3930	88	733.83	333.16	192308	87308	95	792.2	359.67	207605	94253	1.2	10	4.54	2623	1191	0.97	8.08	3.67	2119	962
*3930		3801	1726.16	996272	442308		4792.2	2176	1256063	570253		123.43	56.04	32336	14681		148.08	67.27	38815	17622
1825	27	2204	1001	88100	40000	75	6130	2783	24669	11200	0.55	44.9	20.4	1806	820	6.1	498	226.3	20044	9100
1825	23	613.6	278.6	24737	11231	48	12810	581.6	51625	23438	0.12	3.2	1.454	129.9	59	2.6	69.38	31.5	2797	1270
1825	18	240.15	109.03	9678	4394	70	934	424	37638	17088	1.1	14.67	6.66	592.5	269	0.07	0.934	0.424	37.44	17
1825	37	9.25	4.2	372.2	169	65	16.25	7.38	656	298	0.5	0.1233	0.056	5.044	2.29	4.6	1.149	0.522	46.25	21
*1825		3067	1392.83	122887	55794		19890	3786	114588	52024		62.89	28.57	2533	1150.3		569.46	258.74	22924	10408
3920	-	-	-	-	-	-38	-2282	-1035	-296600	-134500	0.6	30.02	13.63	3900	1771	-0.8	-48.04	-21.79	-6000	-2700
1816	-	-	-	-	-	216	1799	817	177482	80577	-0.13	-1.083	-0.492	-105.72	-48	-1.35	-11.25	-5.11	-1110	-504
2608	23	287.7	130.5	37600	17100	-63	-787174	-357.77	-99125	-45033	-	-	-	-	-	-0.19	-2.37	-1.08	-299.6	-136
0111	-	-	-	-	-	226.4	13855	6235	755868	343164	-	-	-	-	-	-	-	-	-	-
4704	-	-	-	-	-	-6.2	-210.7	-95.68	-21346	-9691	-	-	-	-	-	-	-	-	-	-
2119	-	-	-	-	-	-93.6	-8390	-3809	-266709	-121086	-	-	-	-	-	-	-	-	-	-
2119	-	-	-	-	-	-13.7	-2464	-1118	-77985	-35405	-	-	-	-	-	-	-	-	-	-
*2119		-	-	-	-		-10854	-4927	-344694	-156491		-	-	-	-		-	-	-	-
0101	-	-	-	-	-	-16	-96.07	-43.61	-16736	-7598	-	-	-	-	-	-	-	-	-	-
3514	-	-	-	-	-	443.7	10620	4821	938600	426100	-	-	-	-	-	--	-	-	-	-
1716	-45	-187.66	-85.2	-16916	-7680	-22	-91.74	-41.65	-8260	-3750	0.4	1.670	0.76	149.78	68	0.09	0.374	0.17	33	15
1716	-136	-170	-77.24	-15339	-6964	15	18.76	8.51	1692	768	-5	-6.255	-2.84	-564	-256	0.23	0.287	0.13	26	12
*1716		-357.6	-162.4	-32255	-13644		-72.98	-33.14	-6568	-2782		-4.585	-2.08	415.78	-188		0.661	0.3	59	27

*total of more than one waste stream for plant

TABLE A-V- 9

CHEMICAL WASTE CHARACTERIZATION

ASH POND OVERFLOW - NET DISCHARGE (continued)

CHANGE IN PARAMETER LEVEL FROM INTAKE TO DISCHARGE

Plant Code	Chloride					Copper					Iron					Manganese				
	mg/l	(lb/day)	kg/day	(lb/MWHr) x 10^6	kg/MWHr x 10^6	mg/l	(lb/day)	kg/day	(lb/MWHr) x 10^6	kg/MWHr x 10^6	mg/l	(lb/day)	kg/day	(lb/MWHr) x 10^6	kg/MWHr x 10^6	mg/l	(lb/day)	kg/day	(lb/MWHr) x 10^6	kg/MWHr x 10^6
3412	2415	104121	47271	7885000	3577000	-0.001	-0.043	-0.0196	-3	-1	-0.479	-20.65	-9.376	-1600	-726	-	-	-	-	-
3416	-1	-28.85	-13.1	-3215	-1460	0	0	0	0	0	0.045	1.297	0.589	125.55	57	-	-	-	-	-
3404	1700	9570	4345	1765918	801727	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3402	13.5	81.01	36.78	16319	7409	-0.006	-0.0359	-0.0163	-6.6	-3	-4.6	-27.62	-12.54	-5563	-2626	-	-	-	-	-
3401	-140	-2815	-1278	-3230000	-1470000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1703	15	750.5	340.74	119350	54185	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1720	75	8130	3691	503295	228496	-	-	-	-	-	0.6	65	29.53	4008	1820	-	-	-	-	-
1710	1	6	2.726	1898	862	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1722	34	7372	3347	473678	215050	-	-	-	-	-	0.28	60.7	27.56	3898	1770	0.02	4.34	1.97	277.5	126
1709	81	675.3	306.6	77588	35225	0.02	0.166	0.075	18.94	8.6	0.001	0.008326	0.00378	0.9559	0.434	0.0002	0.001652	0.00075	0.189	0.0861
1711	21	1506	683.7	68859	31262	-	-	-	-	-	0	0	0	0	0	-	-	-	-	-
1711	-16	-93.4	-42.4	-4271	-1939	-	-	-	-	-	-0.252	-1.4978	-0.68	-68.28	-31	-	-	-	-	-
*1711		1412.6	641.3	64588	29323		-	-	-	-		-1.4978	-0.68	-68.28	-31	-	-	-	-	-
3936	35	291.85	132.5	15431	7006	-	-	-	-	-	0.034	0.2819	0.128	14.98	6.8	-	-	-	-	-
3936	51	2551	1158.5	134909	61249	-	-	-	-	-	0.040	2.0	0.908	105.72	48	-	-	-	-	-
*3936		2842	1291	150340	68255	-	-	-	-	-		2.2819	1.208	120.70	54.8	-	-	-	-	-
3927	161	1879	853.3	86594	39314	0.005	0.0573	0.026	2.62	1.19	0.099	1.15	0.524	52.86	24	0.076	8.85	4.02	40.74	18.5
2616	2	70.04	31.8	4907	2228	-	-	-	-	-	1.770	61.98	28.14	4341	1971	-	-	-	-	-
1808	1	33.35	15.144	2768	1257	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1729	41	164.1	74.5	55101	25016	-0.037	-0.148	-0.0672	-50.66	-23	-0.593	-2.37	-1.077	-797	-362	-	-	-	-	-
1718	8	934	424	67400	30600	-	-	-	-	-	-0.387	-45.8	-20.8	-3306	-1501	-	-	-	-	-
3930	120	4002	1817	1049000	476226	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3930	120	1000	454.3	262240	119057	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
*3930		5002	2271	1311000	595283		-	-	-	-		-	-	-	-		-	-	-	-
1825	30	2451	1113	98804	44857	-	-	-	-	-	0.02	1.634	0.742	63.87	29	-	-	-	-	-
1825	29	773.78	351.3	31189	14160	-	-	-	-	-	0.09	2.4	1.09	96.9	44	-	-	-	-	-
1825	32	426.8	193.8	17207	7812	-	-	-	-	-	0.032	0.4270	0.194	17.6	8	-	-	-	-	-
1825	152	38.01	17.26	1533	696	-	-	-	-	-	0.098	0.0245	0.0111	0.984	0.447	-	-	-	-	-
*1825		3689	1675	148733	67525		-	-	-		0.141	4.4855	2.037	179.35	81.447		-	-	-	-
3920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1816	41	341.4	155	33480	15200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2608	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
0111	-2.5	-153	-69.46	-8421	-3823	-	-	-	-	-	0.44	26.92	12.22	1482	673	-0.02	-1.224	-0.555	-68	-31
4704	-43.7	-1485	-674	-150449	-68303	-	-	-	-	-	2.894	98.37	44.66	9963	4523	0.102	3.467	1.574	350	159
2119	-13.4	-1201	-545.3	-38183	-17335	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2119	-16.4	-2971	-1349	-94458	-42884	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
*2119		-4172	-1894	-132641	-60219		-	-	-	-		-	-	-	-		-	-	-	-
0107	-	-	-	-	-	0.06	0.36	0.1635	62	28	0.15	0.9	0.409	32	71	-	-	-	-	-
3514	73	1747	793.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1716	163	679.6	308.56	61273	27818	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1716	26	32.52	14.76	2932	1331	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
*1716		712.1	323.32	64105	29149		-	-	-	-		-	-	-	-		-	-	-	-

*total of more than one waste stream for plant

TABLE A-V- 9

CHEMICAL WASTE CHARACTERIZATION

ASH POND OVERFLOW - NET DISCHARGE (continued)

CHANGE IN PARAMETER LEVEL FROM INTAKE TO DISCHARGE

Plant Code	Magnesium					Mercury					Nickel					Zinc				
	mg/l	(lb/day)	kg/day	(lb/MWHr) x 10^6	kg/MWHr x 10^6	mg/l	(lb/day)	kg/day	(lb/MWHr) x 10^6	kg/MWHr x 10^6	mg/l	(lb/day)	kg/day	(lb/MWHr) x 10^6	kg/MWHr x 10^6	mg/l	(lb/day)	kg/day	(lb/MWHr) x 10^6	kg/MWHr x 10^6
3412	156	6724	3053	509200	231000	-	-	-	-	-	-0.054	-2.32	-1.057	-175	-80	-0.014	-0.603	-0.274	-45	-20
3416	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.162	4.67	2.12	453.7	206
3404	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00013	0.00073	0.00032	0.134	0.061
3402	-11	-54.03	-24.53	-10885	-4942	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3401	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.17	3.41	1.552	3951	1794
3405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.117	0.00467	0.00212	2.86	1.301
1703	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0	0	0
1720	18	1951	886	120704	54800	-	-	-	-	-	-	-	-	-	-	-0.073	-7.9	-3.59	-489	-222
1710	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1722	25	5420	2461	348017	158000	0.0002	0.044	0.0197	2.77	1.26	0.01	2.167	0.984	139.2	63.2	0.03	6.5	2.953	416.23	189
1709	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.011	0.09	0.041	10.35	4.7
1711	-3	-215.6	-97.9	-9846	-4470	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1711	10	58.37	26.5	2669	1212	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
*1711		-157.23	-71.4	-7177	-3258		-	-	-	-		-	-	-	-	-	-	-	-	-
3936	15	125.11	56.8	6608	3000		-	-	-	-	-	-	-	-	-	0.009	0.0749	0.034	3.94	1.79
3936	14	700	318	37037	16815	-	-	-	-	-	-	-	-	-	-	0.009	0.45	0.2044	24.23	11
*3936		825.11	374.8	43645	19815		-	-	-	-		-	-	-	-		0.5249	0.2384	28.17	12.79
3927	21	244.5	111	11233	5100	-	-	-	-	-	0.011	0.1277	0.058	5.88	2.67	0.003	0.035	0.0159	1.6	0.73
2616	0.1	3.50	1.59	3898	1770	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1808	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-0.01	-0.332	-0.151	-2.75	-1.25
1729	-	-	-	-	-	-0.002	-0.00793	-0.0036	-0.44	-0.2	-	-	-	-	-	-	-	-	-	-
1718	-2	-233.48	-106	-16850	-7650	-	-	-	-	-	-	-	-	-	-	0.03	3.5	1.59	253.3	115
3930	-	-	-	-	-	-	-	-	-	-	0.015	0.5	0.227	130.83	59.4	0.003	0.099	0.0450	24.229	11
3930	-	-	-	-	-	-	-	-	-	-	0.008	0.066	0.0302	17.62	8	0.013	0.108	0.0492	28.63	13
*3930		-	-	-	-		-	-	-	-		0.566	0.257	148.45	67.4		0.207	0.0942	52.959	24
1825	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	0.07	5.7	2.59	231.27	105
1825	12	320.26	145.4	12907	5860	-	-	-	-	-	-	-	-	-	-	-0.007	-0.185	-0.084	-6.6	-3
1825	11	146.76	66.63	5914	2685	-	-	-	-	-	-	-	-	-	-	-0.006	-0.079	-0.036	-2.2	-1
1825	12	2.99	1.36	121.1	55	-	-	-	-	-	-	-	-	-	-	0.001	0.000251	0.000114	0.011	0.005
*1825		470	213.4	13942	8600		-	-	-	-		-	-	-	-		5.436	2.47	222.48	101
3920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1816	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2608	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
0111	-3.8	-232.55	-105.58	-12800	-5811	-	-	-	-	-	-	-	-	-	-	-	-	-	- -	-
4704	-1.9	-64.58	-29.32	-6542	-2970	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2119	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2119	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
*2119		-	-	-	-		-	-	-	-		-	-	-	-	-	-	-	-	-
0107	-	-	-	-	-	0	0	0	0	0	-	-	-	-	-	0.05	0.30	0.14	50	24
3514	10	239.36	108.67	21100	9600		-	-	-	-	-	-	-	-	-	-	-	-	-	-
1716	6	25.02	11.36	2247	1020	-	-	-	-	-	-	-	-	-	-	0.12	0.5	0.227	44	20
1716	18	22.52	10.22	2031	922	-	-	-	-	-	-	-	-	-	-	-0.02	-0.025	-0.0113	-2.2	-1
*1716		47.54	21.58	4278	1942		-	-	-	-		-	-	-	-		0.475	0.216	41.8	19

*Total of more than one waste stream for plant

TABLE A-V- 9

CHEMICAL WASTE CHARACTERIZATION

ASH POND OVERFLOW - NET DISCHARGE (continued)

CHANGE IN PARAMETER LEVEL FROM INTAKE TO DISCHARGE

Plant Code	Phosphorus (P)					Turbidity	Sulfite, Lead, Oil and Grease, Phenols, Surfactants, Algicides
	mg/l	(lb/day)	kg/day	(lb/MWHr) x 10^6	kg/MWHr x 10^6	JTU	
3412	-	-	-	-	-	-5	
3416	-	-	-	-	-	13	
3404	0	0	0	0	0	-	
3402	0	0	0	0	0	-29	
3401	-	-	-	-	-	183	NO DATA
3405	-0.5	-0.02	-0.01	-10	-5	8	
1703	-0.33	16.5	-7.49	-2623	-1191	0	
1720	-0.7	-75.88	-34.45	-33480	-15200	-	
1710	-	-	-	-	-	-	
1722	-0.09	-19.51	-8.86	-1253	-569	10	
1709	-1.19	-9.91	-4.5	-1136	-516	27	
1711	-0.7	-50.22	-22.8	-2290	-1040	-14	
1711	-	-	-	-	-	1	
*1711		-50.22	-22.8	-2290	-1040		
3936	0.1	0.815	0.37	41.8	19	-	
3936	0.2	10	4.54	528	240	-	
*3936		10.815	4.91	569.8	259	-	
3927	0.14	1.63	0.74	74.89	34	-	
2616	0	0	0	0	0	-	
1808	0.26	8.65	3.93	718	326	-	
1729	0.08	0.319	0.145	107.93	49	-	
1718	-0.05	-5.83	-2.65	-420	-191	-	
3930	-	-	-	-	-	-2	
3930	-	-	-	-	-	-22	
*3930		-	-	-	-	-	
1825	-	-	-	-	-	-	
1825	-	-	-	-	-	-	
1825	-	-	-	-	-	-	
1825	-	-	-	-	-	-	
*1825		-	-	-	-	-	
3920	-0.09	-5.4	-2.45	-702.6	-319	-	
1816	0.41	3.41	1.55	337	153	-	
2608	-0.06	-0.749	-0.34	-94.7	-43	-	
0111	-	-	-	-	-	-	
4704	-	-	-	-	-	-	
2119	-	-	-	-	-	-2.2	
2119	-	-	-	-	-	16.3	
*2119		-	-	-	-	-	
0107	-	-	-	-	-	-	
3514	-	-	-	-	-	-	
1716	-0.23	-0.958	-0.435	-85.9	-39	-13	
1716	-0.23	-0.280	-0.13	26	12	-13	
*1716		-1.238	-0.565	-59.9	-27	-	

*total of more than one waste stream for plant

In that table, plant capacities range from 31 Mw to 2,533 Mw and the ash pond overflow varies between 1,817 cu m/day (480,000 gpd) and 122,946 cu m/day (32,473,000 gpd).

Because of the large variation in quality of coal used in powerplants, the data also show a wide variation in concentration of trace metals in the effluent. Some of the metals discharged may be harmful to aquatic life.

Oil

The ash content of fuel oils is low (about 1% of the amount commonly found in coal).[278] It is generally 0.10 to 0.15% by weight, although it may be as high as 0.2%.

The quantity of ash produced in an oil-fired plant is very small, but the settling characteristics of oil ash are not as favorable as those of coal ash. It has been found that in some cases recycling oil fly into the furnance increases efficiency and eliminates the fly ash disposal problem. Depending on the vanadium content of the oil, the dry bottom ash can actually be a saleable by-product.

Most oil ash deposits are partially soluble and can be removed by water washing. Generally the washing is done while the unit is out of service. In-service water washing at reduced loads has been practiced to some extent, using the hot, high-pH boiler water in carefully regulated amounts.

Limited data are available on the characteristics of oil ash handling waste water. Table A-V-9 lists 6 plants which use both coal and oil, but only one plant is listed using oil alone. No data are reported for vanadium in waste streams. In certain cases, however, when other means of collecting the vanadium are not available, the content of vanadium in waste water should be evaluated, because of its possibly toxic effect on aquatic life.

Coal Pile Runoff

For coal-fired generating plants, outside storage of coal at or near the site is necessary to assure continuous plant operation. Normally, a supply of 90 days is maintained. These storage piles are typically 8 to 12 meters (25-40 ft) high spread over an area of several square meters (or acres). Typically from 600 to 1,800 cubic meters (780 to 2340 cu yd) are required for coal storage for every Mw of rated capacity. As such a 1000 Mw plant would require from 600,000 to 1,800,000 cubic meters (78,000 to 2,340,000 cu yd) of storage. Depending on coal pile height, this represents between 60,000 to 300,000 square meters (15-75 acres) of coal storage area.

Coal is stored either in active piles or storage piles. Active piles are open and contact of active coal with air and moisture results in oxidation of metal sulfides, present in the coal, to sulfuric acid. The precipitation trickles or seeps into coal piles. When rain falls on these piles, the acid is washed out and eventually winds up in coal pile runoff. Storage piles are sometimes sprayed with a tar to seal their outer surface. In such cases, the precipitation runs down the side of the pile.

Based on typical rainfall rates, pile runoff may range from 64,000 to over 32,0000 cubic meters (17 to 85 million gallons) per year with average figures around 75,000 to 100,000 cubic meters (20 to 26 million gallons) per year. Table A-V-10 presents the amount of coal consumed per day, area and height of coal pile, average rainfall and runoff from various coal-fired generating plants across the country.

Liquid drainage from coal storage piles presents a potential danger of stream contamination, if it is allowed to drain into waterways or to seep into useful aquifers. Ground seepage can be minimized by storing the coal on an imprevious base. Vinyl liners of various thicknesses have been used for that purpose. To prevent the sharp edges of coal particles from puncturing the liner, a 15 cm(6") bed of sand or earth is placed on top of a liner before forming the coal pile.

Water pollution associated with coal pile runoff is due to the chemical pollutants and suspended solids usually transported in coal pile drainage. Drainage quality and quantity is variable, depending on the meteorological condition, area of pile and type of coal used. Areas of high average rainfall have much higher drainage than those of low average rainfall. Contact of coal with air and moisture results in oxidation of metal sulfides to sulfuric acid and precipitation of ferric compounds. High humidity areas have higher precipitation and produce larger runoffs.

Coal pile runoff is commonly characterized as having a low pH (high acidity) and a high concentration of total dissolved solids including iron, magnesium and sulfate. Undesirable concentrations of aluminum, sodium, manganese and other metals may also be present. Contact of coal with air and moisture results in oxidation of the metal sulfides present in the coal to sulfuric acid. Pyrites are also oxidized by ferric ion to produce ferrous sulfate. When rain

TABLE A-V-10

COAL PILE DRAINAGE

PLANT ID	COAL CONSUMED/DAY		AREA OF PILE		HEIGHT OF PILE		AVERAGE ANNUAL RAINFALL		RUN-OFF PER YEAR	
	lbs x10^6	Kgs x10^6	Acres	M^2 x10^3	Ft.	Meters	Inches	Meters	Million Gallons	M^3 x10^3
4701	15	6.81	25	101.85	40	12.19	44	1.117	20	75.7
4706	31	14.07	58	236.29	25	7.62	-	-	-	-
4702	15	6.81	75	305.55	17	5.18	54.7	1.389	25	94.62
4705	27.6	12.53	28	114.07	25	7.62	-	-	-	-
4703	20.6	9.35	18	73.33	40	12.19	45.84	1.164	25	94.62
2120	25.4	11.53	61	248.5	22	6.7	-	-	-	-
4704	14.34	6.51	21	85.55	25	7.62	43.1	1.094	17	64.34
2119	47.6	21.6	25	101.85	-	-	44.4	1.1277	22	83.27
0112	35.8	16.25	25	101.85	40	12.19	-	-	26.5	100.3
5305	-	-	120	488.8	-	-	60	1.524	-	-

falls on these piles, the acid is washed out and eventually winds up in the coal pile drainage. At the low pH produced, other metals such as aluminum, copper, manganese, zinc, etc. are dissolved to further degrade the water.

Coal pile runoff, like coal mine drainage, can be classified into three distinct types according to chemical characteristics. The first type of drainage will usually have a pH of 6.5 to 7.5 or greater, very little or no acidity, and contain iron, usually in the ferrous state. Alkaline drainage may occur where no acid-producing material is associated with the mineral seam or where the acid is neutralized by alkaline material present in the coal. Some alkaline waters have high concentration of ferrous ion, and, upon oxidation and hydrolysis, precipitate large amounts of iron.

A second type of drainage is highly acidic. This water contains large amount of iron, mostly in ferrous state, and aluminum.

Although the exact reaction process is still not fully understood, the formation of acid coal pile drainage can be illustrated by the following equations. Initial reaction that occurs when iron sulfate and sulfuric acid

$$2\ FeS_2 + 7\ O_2 + 2\ H_2O = 2\ FeSO_4 + 2\ H_2SO_4$$

Subsequent oxidation of ferrous sulfate produces ferric sulfate:

$$4\ FeSO_4 + 2\ H_2SO_4 + O_2 = 2Fe_2(SO_4)_3 + 2\ H_2O$$

Depending on physical and chemical conditions, the reaction may then proceed to form ferric hydroxide or basic ferric sulfate:

$$Fe_2(SO_4)_3 + 6H_2O = 2Fe(OH)_3 + 3H_2SO_4$$

$$Fe_2(SO_4)_3 + 2H_2O = 2Fe(OH)(SO_4) + H_2SO_4$$

Pyrites can also be oxidized to ferric ions as shown below:

$$FeS_2 + 14\ Fe^{+3} + 8H_2O = 15\ Fe^{+2} + 2SO_4^{-2} + 16H^{+}$$

Regardless of the reaction mechanism, the oxidation of one mole of pyrite ultimately leads to the release of two moles of sulfuric acid (acidity).

Other constitutents found in coal pile drainage are produced by secondary reactions of sulfuric acid with minerals and organic compounds present in the coal. Such secondary reactions are dependent upon type of coal and physico-chemical conditions of the pile.

The pollution of streams by coal-pile runoff may be attributed to higher concentration of dissolved solids, mineral acid, iron, and sulfate present in the runoff. In addition, aluminum, copper, zinc and manganese may be present. The degree of harm caused by these elements is compounded by synergism among several of them; for example zinc with copper. The harmful effects of iron, copper and zinc solutions can be greater in the acid water polluted by coal pile drainage than in neutral or alkaline water. Data reported from various plants are shown in Table A-V-11. An inspection of these data reveals an extremely large variation in the pollutant parameters listed. The concentration of runoff is dependent on the type of coal used, history of the pile and rate of flow. Plant nos. 1729, 3626, and 0107 using high sulfur coal are highly acidic (low pH), and have high sulfate and metallic concentrations.

The acidity, sulfate and metal concentrations of plant no. 3505 which uses very low sulfur coal are very small. The concentration of pollutants during heavy rainfall will be very small after an initial removal of precipitated material from coal, while during low flow conditions the retention time may be high enough to complete oxidation, resulting in higher runoff concentrations.

Floor and Yard Drains

A steam electric powerplant contains a number of potential sources of wastewater in the nature of piping and equipment drainage and leakage. The list in Table A-V-12 is a representative compilation of sources, showing major contaminants, the likely frequency, potential severity of discharges, and control technologies that might be considered.

The floor drains within a powerplant which collect equipment drainage and leakage generally include dust, fly ash, coal dust (coal-fired plants) and floor scrubbing detergent. This waste stream also contains lubricating oil or other oils which are washed away during equipment cleaning, oil from leakage of pump seals, etc., and oil collected from spillage around storage tank area.

TABLE A-V-11

CHEMICAL WASTE CHARACTERIZATION

COAL PILE DRAINAGE

Discharge Concentrations

Line	A Plant Code	B Alkalinity mg/l	C BOD mg/l	D COD mg/l	E TS mg/l	F TDS mg/l	G TSS mg/l	H Ammonia mg/l	I Nitrate mg/l	J Phosphorus mg/l	K Turbidity mg/l	L Acidity mg/l	M Total Hardness mg/l	N Sulfate mg/l	O Chloride mg/l	P Aluminum mg/l	Q Chromium mg/l
1)	3402	6	0	1080	1330	720	610	0	0.3	-	505	-	130	525	3.6	-	0
2)	3401	0	0	1080	1330	720	610	0	0.3	-	505	-	130	525	3.6	-	0
3)	3936	0	10	806	9999	7743	22	1.77	1.9	1.2	-	-	1109	5231	481	-	0.37
4)	1825	-	-	85	6000	5800	200	1.35	1.8	-	-	-	1850	861	-	-	0.05
5)	1726	82	3	1099	3549	247	3302	0.35	2.25	0.23	-	-	-	133	23	-	-
6)	1729	-	-	-	-	-	-	-	-	-	-	-	-	6837	-	-	-
7)	3626	-	-	-	-	28970	100	-	-	-	-	21700	-	19000	-	1200	15.7
8)	0107	0	-	-	45000	44050	950	-	-	-	-	27810	-	21920	-	825	0.3
9)	5305	21.36	-	-	-	-	-	-	-	-	8.37	8.68	-	-	-	-	-
10)	5305	14.32	-	-	-	-	-	-	-	-	2.77	10.25	-	-	-	-	-
11)	5305	36.41	-	-	-	-	-	-	-	-	6.13	8.84	-	-	-	-	-

Discharge Concentrations

Line	A Plant Code	B Copper mg/l	C Iron mg/l	D Magnesium mg/l	E Zinc mg/l	F Sodium mg/l	G pH pH
1)	3402	1.6	0.168	-	1.6	1260	2.8
2)	3401	1.6	0.168	-	1.6	1260	2.8
3)	3936	-	-	89	2.43	160	3
4)	1825	-	0.06	174	0.006	-	4.4
5)	1726	-	-	-	0.08	-	7.8
6)	1729	-	0.368	-	-	-	2.7
7)	3626	1.8	4700	-	12.5	-	2.1
8)	0107	3.4	93000	-	23	-	2.8
9)	5305	-	1.0	-	-	-	6.7
10)	5305	-	1.05	-	-	-	6.6
11)	5305	-	0.9	-	-	-	6.6

Table A-V-12

Equipment Drainage, Leakage[444]

Source	Major Contaminants	Frequency	Potential Severity	Potential Control Techniques
Oil-water Heat Exchangers	Oil	Remote Possibility	Severe	1. Continuous Gravity Separation 2. Detection and Batch Gravity Separation 3. Detection & Mechanical Separation 4. Maintain pressure of water greater than oil
Oil Tank, Lines & Transformer Rupture	Oil	Remote Possibility	Severe	1. Isolation from Drains 2. Containment of Drainage
Floor spills	Suspended Solids or Oil	Daily	Slight	1. Plug Floor Drain 2. Route Floor Drainage Through Clarifier & gravity or mechanical separation
Oil Drips and Tank Leakage	Oil	Daily	Slight	1. Isolate from Floor Drains 2. Route to Gravity or Mechanical Separation
Sump Discharges from Service Bldg. & Yard	Oil and Suspended Solids	Often	Slight	1. Isolate and route through clarifier and gravity or mechanical separation
Chemical Tank Rupture	Regenerant and cleaning chemicals	Remote Possibility	Severe	1. Containment of Drainage 2. Isolation from Drains 3. Route Drains to Ash Pond or Holding Pond for neutralization
Chemical Tank Leakage	Regenerant and cleaning chemicals	Occasional	Slight	1. Isolate from Floor Drains 2. Route Drains to Ash Pond or Holding Pond

NOTE: Oil Spill Contingency Plans would apply to significant oil releases.

No data regarding the flow and composition of this waste stream have been reported, however, oil, suspended solids, and phosphate from floor scrubbing detergent may be present in the floor drains. The discharge stream will be acidic if any wash water from air preheater or fireside of the boiler winds up in floor drains.

Air Pollution Control Devices

A number of processes have been proposed for removing particulate and SO_2 emissions from stack gases. Some of these processes have been suggested for potential application in fossil-fuel powerplants. In general the SO_2 removal processes can be categorized, according to Reference 123, as follows:

1. Alkali scrubbing using calcium carbonate or lime with no recovery of SO_2.
2. Alkali scrubbing with recovery of SO_2 to produce elemental sulfur or sulfuric acid.
3. Catalytic oxidation of SO_2 in hot flue gases to sulfur trioxide for sulfuric acid formation.
4. Dry-bed absorption of SO_2 from hot flue gases with regeneration and recovery of elemental sulfur.
5. Dry injection of limestone into the boiler furnace for removal of SO_2 by gas-solid reaction.

The removal of particulates from stack gases can also be carried out separately - using an electrostatic precipitator or a dry mechanical collector, wet scrubbing for SO_2 removal can be applied subsequently.

The waste water problems are mainly concerned with wet processes (first three types mentioned above). Wastewater problems associated with particulate (fly-ash) removal devices are described in an earlier portion of this section of the report.

At present three wet processes are under development or in use: alkali scrubbing with and without SO_2 recovery, and oxidation of SO_2 for sulfuric acid production. Of the three processes, data is available mainly for the alkali scrubbing process without SO_2 recovery, and consequently only this process is described briefly in the following paragraph.

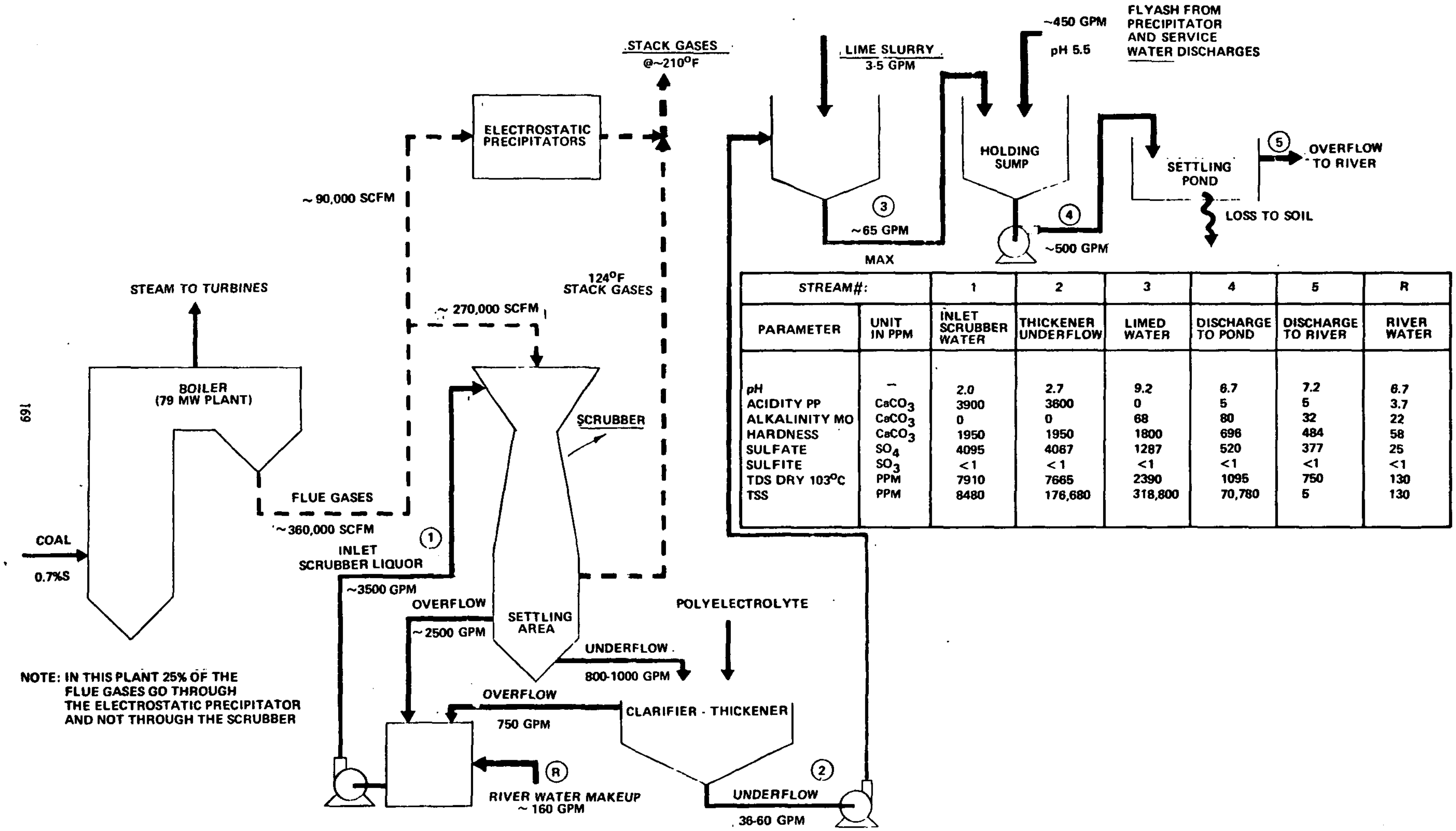
Flue gas from electrostatic precipitators (optional equipment) is cooled and saturated by water spray. It then passes through a contacting (scrubbing) device where SO_2 is removed by an aqueous stream of lime absorbent. The clean gas is then reheated (optional step) and vented to the atmosphere through an induced draft fan if necessary. The lime absorbent necessary for scrubbing is produced by slaking and diluting quicklime in commercial equipment and passing it to the delay tank for recycle as a slurry through the absorber column(s). Use of the delay tank provides sufficient residence time for the reaction of dissolved SO_2 and alkali to produce calcium sulfite and sulfate. The waste sulfite/sulfate is them pumped as a slurry to a lined settling pond or mechanical system where sulfite is oxidized to sulfate. The clear supernatent liquid is returned to the process for reuse. The waste sludge containing fly ash (if electrostatic precipitator is not employed) and calcium sulfate is sent for disposal (as a landfill).

The process described above has the potential for scaling problems. The calcium salts tend to form a deposit, which may cause equipment shutdown and maintenance.

The process is a closed loop type and consequently there is no net liquid discharge from the process. The disposal of sludge has been covered in the literature. However, depending upon the solids separation efficiency in a pond or mechanical equipment, there may be excess free water associated with the sludge. To dewater this sludge, mechanical filtration equipment may be necessary.

To date eleven or more utilities have committed themselves to full-scale installation of the alkaliscrubbing process without SO_2 recovery. During the course of the present study, visits were made to two plants for observing the scrubbing devices. However, in plant no. 1720, the scrubber was not running because of operational problems. The process for the other plant (no. 4216) is described below.

Plant no. 4216 of 79 Mw capacity burns 0.7% sulfur coal. The boiler gases are split into two streams - approximately 75% going to a scrubber and the remaining 25% going to an electrostatic precipitator. The exhaust gases from the two are then recombined and vented to atmosphere at 210°F. This splitting of the boiler gases is done to reheat the scrubber exhaust gases which are at 124°F (saturated). This stack gas reheating is achieved to minimize scaling problems from moist gases. The scrubber is not specifically used for SO_2 removal. Rather, the primary function is to remove particulates. On the other hand, some SO_2 pick-up may be achieved based on Figure A-V-10 where the net output from the process (thickener underflow) is richer in sulfate than the



STREAM#:		1	2	3	4	5	R
PARAMETER	UNIT IN PPM	INLET SCRUBBER WATER	THICKENER UNDERFLOW	LIMED WATER	DISCHARGE TO POND	DISCHARGE TO RIVER	RIVER WATER
pH	–	2.0	2.7	9.2	6.7	7.2	6.7
ACIDITY PP	$CaCO_3$	3900	3600	0	5	5	3.7
ALKALINITY MO	$CaCO_3$	0	0	68	80	32	22
HARDNESS	$CaCO_3$	1950	1950	1800	696	484	58
SULFATE	SO_4	4095	4067	1287	520	377	25
SULFITE	SO_3	<1	<1	<1	<1	<1	<1
TDS DRY 103°C	PPM	7910	7665	2390	1095	750	130
TSS	PPM	8480	176,680	318,800	70,780	5	130

NOTE: IN THIS PLANT 25% OF THE FLUE GASES GO THROUGH THE ELECTROSTATIC PRECIPITATOR AND NOT THROUGH THE SCRUBBER

FIGURE A-V-10 FLOW DIAGRAM AIR POLLUTION CONTROL SCRUBBING SYSTEM AT PLANT NO. 4216 process input (river water). However, some of the increase in sulfate may be due to chemicals added to enhance particulate removal. The flow diagram and the different stream compositions are shown in Figure No. A-V-10.

For a more complete review of the status of air pollution control technology for steam electric powerplants, see References 470-473.

Sanitary Wastes

The amount of sanitary waste depends upon the number of employees. This in turn is dependent upon the type of plant--coal, oil, or gas, its size and its age. A powerplant employs administrative personnel and plant personnel (plant crews and maintenance personnel). Coal-fired plants require more operational personnel then others. For a coal-fired plant, the breakdown in types of employees is typically as follows:

operational personnel:	1 per 20-40 Mw
maintenance personnel:	1 per 10-15 Mw
administrative personnel:	1 per 15-25 Mw

A typical three boiler 1,000 Mw coal-fired plant may employ 150-300 people. Whereas, in a oil plant of similar size, the total number of employees may be in the range of 80-150.

The typical parameters which define the pollutional characteristics of sanitary wastes are BOD-5 and suspended solids. The following table lists per capita design estimates for the waste stream:

	FLOW	BOD-5	TSS
Office-Admin.	0.095cu m/day (25 gpd)	30 g (0.07 lb)	70 g (0.15 lb)
Plant	0.133 cu m/day (35 gpd)	40 g (0.09 lb)	85 g (0.19 lb)

Knowing the number of personnel in the office-administrative and plant categories, the characteristics of the raw sewage waste stream can be estimated. Typically, for an oil-fired plant generating 1,000 Mw the personnel required might be 20 office and administrative, and 85 plant personnel. The raw sewage characteristics for this plant can be estimated on the basis presented above as follows:

	FLOW	BOD-5	TSS
Office-Admin.	1.890 cu m/day (500 gpd)	635 g (1.40 lb)	1360 g (3.00 lb)
Plant	1.125 cu m/day (2975 gpd)	3480 g (7.65 lb)	7330 g (16.15 lb)
Total	3.015 cu m/day (3475 gpd)	4115 g (9.05 lb)	8690 g (19.15 lb)

The sanitary waste from steam electric powerplants is generally similar to municipal sanitary wastes with the exception that powerplant wastes do not normally contain laundry or kitchen wastes. Moreover, the per capita hydraulic loading for powerplant personnel is relatively small (25 to 35 gallons) in comparision to domestic usage (100 to 150 gallons). Normally the local health agencies dictate requirements for treating sanitary wastes. In metropolitan areas, the raw sewage may be discharged to a municipal treatment plant. In rural areas, packaged treatment plants for sanitary wastes may be employed.

Plant Laboratory and Sampling Streams

Laboratory facilities are maintained in many steam electric powerplants to carry out chemical analysis for checking different operations such as ion exchange, water treatment, boiler tube cleaning requirements, etc. The size of the laboratory depends upon the size, type, and age of the plant. Modern high pressure steam plants require closer control on the operations and consequently increased laboratory activity. In nuclear plants the use of a laboratory is extensive.

The waste from laboratories vary in quantity and constituents, depending upon the use of the facilities and the type of powerplant.

Laboratory facilities for steam electric powerplants also vary considerably depending on the age of the plant and the extent to which different companies rely on plant labs for their chemical analysis needs. For some plants, particularly small and older plants, no laboratory work is done on site and samples are shipped to central laboratories for analysis. In others, and especially modern, high-pressure steam plants and nuclear facilities, much more laboratory support is required.

Laboratory wastewater can contain a wide array of chemicals, although they are usually present in extremely small amounts. Chrarcteristics are also highly variable and could entail a wide range of pH. It has been common practice to combine laboratory drains with other plant plumbing and consequently data on representative analysis, flows or special treatment procedures are not available. In general, it would appear that a toxic materials inventory approach to account for chemicals that might be discharged to laboratory drains would be more practical than conducting an analysis on the wastewater.

If a problem is shown to exist because of contamination through a laboratory drain, approaches to control would involve a wide range of alternatives ranging from a revision of the specific test procedure causing the difficulty to a batch analysis, containment and separate treatment of the waste or removal from the site.

Intake Screen Wash

Powerplants require water for various operations. Plants using once-through type condenser cooling systems draw the cooling water from a waterbody such as an ocean, a lake, a river, etc. On the other hand, plants using a recirculating condenser cooling system need less water intake than the once-through types. Depending upon the water requirements and the source of intake water, traveling screens are used to prevent river debris, fish, leaves, etc. from entering the intake system. The accumulated debris is collected and the screens hosed down to prevent plugging.

Service Water System

Service water systems supply water which is used for such house services as bearing and gland cooling for pumps and fans, auxiliary cooling and heat exchangers, hydrogen cooler and fire pumps. In many cases toilet and potable water is included in this category.

According to Reference 21, there are basically two types of service water systems. Once-through service water systems are most common. In these types raw water with no treatment chemical is added. These types of systems are operated in parallel to the condenser cooling water system. Raw water is used and no continuous treatment is practiced. Occasional shock chlorination is given to similar levels as with condenser cooling water. Chlorination treatment is, however, much less frequent. Many nuclear plants integrate the emergency core cooling system with a once-through service water system. Once-through service water systems can be used exclusively or in conjunction with closed-loop recirculatory systems. With recirculatory systems the makeup can be supplied from either raw or city water. This makeup is pretreated to a high degree of purity. This closed loop recirculatory water is treated to a high degree to prevent corrosion within the system. In general, chromates are used in conjunction with caustic soda for control of pH at 9.5 to 10 up to levels of 250 ppm. Borate-nitrate corrosion inhibition treatment is also used to levels of between 500 to 2,000 ppm. Generally, there is little or no loss from these closed-loop systems. The only occasions when water loss can occur are during maintenance or occasionally if the system has to be drained for cleaning, which although infrequent can occur at a three year frequency.

Service water requirements cover a wide range. For once-through systems water flows range from 0.5 to 35 gpm per Mw of rated plant capacity. Typically, the flow is 10 to 11 gpm per Mw of rated capacity. Where closed-loop systems are operated a figure of 22 to 23 gpm per Mw of rated capacity is typical. On this basis, closed-loop blowdown can typically be 5 gallons per day with a settleable solids content of 1 to 2 ppm. Service water requirements of plant no. 4251, a nuclear unit of 851 Mw using 480,000 gpm of main condenser cooling water, are as follows:

Primary plant component cooling water	5,800 gpm
Secondary plant component cooling water	16,000 gpm
Centrifugal water chiller	3,000 gpm
Control room air conditioner	210 gpm

Low Level Rad Wastes

The radioactive waste handling system is beyond the scope of this study. Some of the low level rad wastes from a nuclear powerplant contain boron and therefore can also be considered as chemical wastes. Consequently, a brief description of the waste handling systems in a nuclear powerplant is included. The sources of radioactive wastes are the reactor coolant and spent fuel coolant and the various systems with which these coolants come into contact. In general, the radioactive fluids are treated by filtration, ion exchange, and distillation. The fluids are then either recycled for use in the plant or diluted with condenser cooling water for discharge to the environment.

Most commercial nuclear powerplants in the country are either pressurized water reactors (PWRs) or boiling water reactors (BWRs). In a pressurized water reactor, the primary coolant is maintained at a pressure (2,200 psi) sufficient to keep it from boiling. After the primary coolant is heated in the reactor, it flows through the tube side of large heat exchangers generating steam on the shellside. This steam is used to drive the turbine and is then condensed and returned to the steam generator through a series of preheaters. Thus, in a PWR, the primary coolant is isolated from the steam-condensate system. However, some leakage through defects in steam-generator tubes may occur resulting in contamination of the steam-condensate system. There are several other fluid systems which may be contaminated. In a PWR, boron is used in the primary coolant to help control reactivity. As the fuel burn-up progresses, the boron concentration is lowered by feed and bleed of reactor coolant.

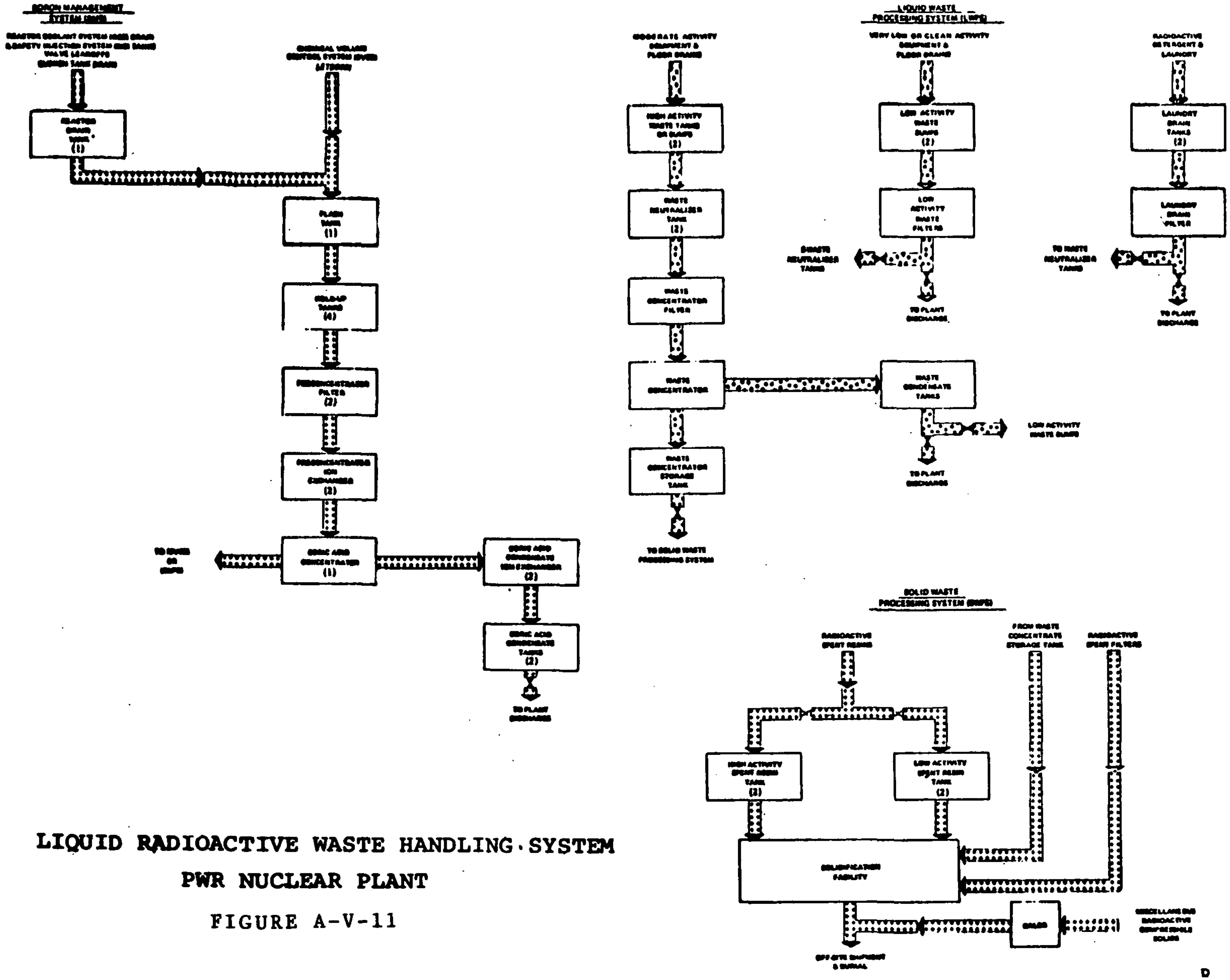
Two systems are associated with this process. The first system, which is sometimes called the chemical and volume control system (CVCS), is on stream at all times and is used to control the radioactivity chemistry and volume of reactor coolant. Reactor coolant is continously bled from the primary system into the CVCS where it usually passes through filters and ion exchangers. The coolant can then be returned to the reactor or diverted to the second system to allow addition of water with a different boron concentration to the reactor through the CVCS. The second system can be labeled the boron management system (BMS). It processes the reactor coolant letdown after it has passed through the CVCS ion exchangers. Processing in the BMS usually includes gas stripping to remove hydrogen and the radioactive noble gases, ion exchange, and distillation. The distillate may be recycled for use as reactor coolant or diluted with condenser cooling water for discharge to the environment. The concentrated bottoms from the distillation process are either recycled as boric acid for use in the reactor coolant or mixed with cement and placed in drums or larger containers for shipment to a solid radioactive waste burial site.

Provisions are made so that after reactor shutdown it is possible to cycle reactor coolant through ion exchangers prior to flooding the reactor area and fuel transfer canal with water from the refueling water tank. However, there is still some residual activity in both the refueling water tank and the fuel storage pools. Thus, it is possible that refueling water, spent fuel coolant, new fuel pool water and secondary coolant are contaminated as well as reactor coolant and letdown. Also, the fluids used to transfer or regenerate resins in any of the systems mentioned above may be contaminated. Therefore, all leaks and resin-handling and regeneration fluids from these systems are collected and processed in a radioactive waste management system (WMS). This WMS also uses filtration, ion exchange, or distillation or a combination of the three to produce very low activity water suitable in most cases for discharge to the environment. Because the WMS processes a wide variety of liquids, some of which may be contaminated with oil or other undesirable substances, the WMS effluent is generally not recycled. Figure A-V-11 shows a block diagram of the liquid radioactive waste management system for a PWR.

In BWRs, the reactor coolant is itself boiled and thus flows through the steam condensate system. The condensate is usually heated and returned to the reactor. The solutions produced in handling or regenerating the ion exchange resins constitute the major radioactive liquid waste in a BWR. In addition to the equipment for "polishing condensate" a system is provided for filtering and demineralizing the reactor coolant. This system, called the reactor water cleanup system (RWCS), takes coolant from the reactor vessel, cools it, filters and demineralizes it and returns it to the reactor coolant system, thus controlling nonvolatile corrosion products and impurities in the reactor water. Because no boric acid is used in the reactor water under normal circumstances there is no feed and bleed operation for boron concentration control and consequently no boron management system.

As in the PWR, the water for refueling also becomes contaminated and any leakage of refueling water as well as any leakage and resin regenerating or transporting fluids and filter backwash (from any of the contaminated systems discussed above) is collected and treated. Treatment of wastes in a BWR also includes filtration, ion exchange, and distillation. The exact design of the systems vary from plant to plant; however, from the liquid radioactive waste point of view, BWRs may be placed in two categories: (1) those which use disposable ground resin in filter demineralizers for condensate polishing, and (2) those which use resin regenerable in deep bed demineralizers. In general, it appears that the former system is favored except where saline cooling water is used.

The use of regenerable resin means that large volumes of regenerant solutions have to be processed every day. The processing usually involves the use of large evaporators with total through-put capacity on the order of 0.0025 cu



LIQUID RADIOACTIVE WASTE HANDLING SYSTEM
PWR NUCLEAR PLANT
FIGURE A-V-11

m/s (40 gpm) or more for some plants. The distillate from these evaporators is generally sent to high-purity waste system for further treatment by ion exchange. About 90% of the effluent of this high-purity waste system is recycled for use in the reactor and 10% discharged.

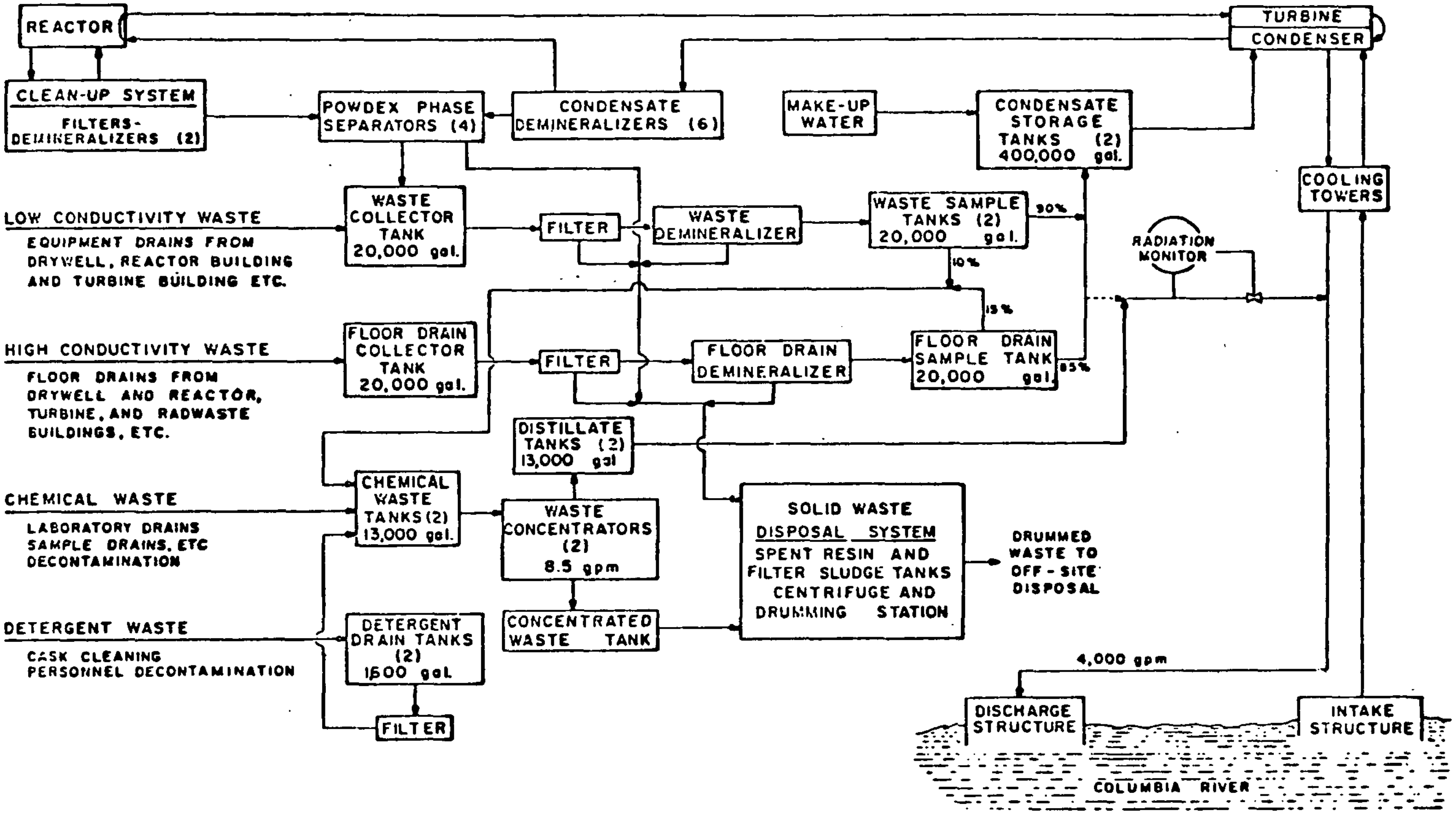
In those plants which use ground resin units for condensate polishing, no regeneration takes place since water is used only to transport the powder. Thus, considerably less fluid has to be treated and, since the radionuclides are not dissolved into the water, only mechanical separation such as settling, filtration and centrifuging is used for initial treatment of the water. Again the water is sent to a high-purity waste system where it is treated by ion exchange and the bulk of the water is recycled for use in the reactor with the remainder discharged into the cooling water.

BWRs usually use ground resin filter demineralizers in the RWCS. The liquid from transporting ground resin in the RWCS is treated in the same way as that used for ground resin condensate polishers.

Other liquid wastes from BWRs are treated by ion exchange, evaporation, and filtration. Other sources of wastes are floor drains and laundry drains (including personnel decontamination and cask cleaning). Distillates from evaporation of these waste are generally discharged to the environment. Concentrated bottoms from evaporators and solids from dewatering equipment are drummed for off-site shipment. Figure A-V-12 shows a block diagram of the liquid radioactive waste handling systems of a BWR of 1,100 Mw capacity.

It is difficult to establish the exact amount of liquid which will be released by the radioactive waste handling systems of a power reactor. The number and type of shutdowns and load changes the amount of leakage from various systems, and the degree of recycle of processed waste all affect the quantities of liquid discharged. However, in the process of obtaining licenses for construction and operation of a nuclear powerplant, estimates are made of these releases based on expected operating conditions. A review of several Environmental Impact Statements for PWRs and BWRs indicates a range of effluent quantities which are expected to be discharged.

PWR wastes processed in the BMS are usually of high enough quality to be recycled. In general, the distillate from BMS's contains concentrations much lower than 1 mg/l of all chemicals other than boric acid which is present at a maxi-



LIQUID RADIOACTIVE WASTE HANDLING SYSTEM
1100 Mw BWR NUCLEAR PLANT
FIGURE A-V-12

mum concentration of 60 mg/l. The anticipated quantities of BMS discharge for a sampling of PWRs ranges from 0 to over 5,000,000 gal/year. The quantity of distillate discharged from the BMS depends on the operating mode of the plant (i.e. base loaded or load following), number of shutdowns and the degree of distillate recycling.

Distillate from the WMS can generally be expected to have the same chemical purity as that from the BMS although it may occasionally contain a few mg/l of sulfates and chlorides resulting from processing condensate polisher regenerants during primary to secondary leaks.

Some of the fluids routed to the WMS are not necessarily treated by the radwaste evaporator. These wastes are expected to be of such low activity that they will be filtered, monitored, and then treated as conventional wastes. The quantity of liquid discharged from the WMS of a PWR can vary widely. For example, during a primary to secondary leak, plant condensate polishers may process the polisher regenerants through the WMS. While this means that millions of gallons of distillate may be discharged from the WMS, it doesn't add to overall plant waste discharged since the regenerants would have to be processed and discharged at nearly the same rate by chemical treatment system in the event there were no primary to secondary leak.

As discussed above, the nature and quantity of liquid discharged by the radioactive waste systems of a BWR differ greatly between units which use ground resin condensate polishing and those which use conventional ion exchangers. Even within a given type of plant there is a large variation in techniques for handling the various wastes and the anticipated discharge quantities vary considerably. For example one plant using ground resin condensate polishers is expected to discharge approximately 1.5 million gallons per year while another also using similar polishers may discharge five times that amount.

Because of the treatment requirements for removing radioisotopes from waste streams, it is expected that most discharges from radioactive waste systems in BWRs will contain extremely low concentrations of chemical pollutants.

Construction Activity

There are liquid wastes associated with on-site construction activities. Such wastes will depend upon the type and size of construction and the location.

Generally, waste water resulting from construction activity will consist of storm water runoff from the site during the course of construction. This stream can be characterized by suspended solids and turbidity resulting from the errosion of soil disturbed by the construction activity.

Construction activity referred to here concerns buildings and equipment immediately related to powerplants and does not address the construction of cooling ponds or cooling lakes, visitor centers, access roads, etc.

Chemical Discharges in General

Effluents from steam electric powerplants contribute a significant portion (14%) of the total national discharge of metals from major industrial point sources. According to information filed by point source dischargers under the National Pollution Discharge Elimination System (NPDES) permit program, steam electric powerplants contribute 50% of the chromium, 14% of the copper, 10% of the iron, 21% of the zinc, and 14% of all metals as a whole, found in the discharges of U.S. industries designated as major dischargers by EPA.

Data from NPDES permit applications stored in the computer file were analyzed in order to determine the percentage of total heavy metal pollutants contributed by the steam electric power industry. The analysis was done for four specific metals: chromium, copper, iron, and zinc.

Data were available for 67% of all major dischargers and for 66% of the major steam electric powerplants. The other 33-34% were not entered into the computer file. The figures include in most cases the contribution from cooling water discharge.

Table A-V-13 shows the relative contribution of metals from powerplants compared to other major industrial sources.

Extrapolating this data to all major and minor dischargers caused little variation in the percentage contribution of powerplants regardless of the assumptions made concerning the relative contributions of major to minor dischargers.

A study by an EPA contractor (ERCO) of coal-fired powerplants showed the following estimates of daily discharge from existing (1973) coal-fired powerplants, in pounds. This study covered only the coal-fired plants and did not include cooling water discharge. The results are given in Table A-V-14

Table A-V-13

Total Metals Discharged from Powerplants in the U.S. (1973) Compared to Other Industrial Sources (Includes cooling water discharges)

Pollutant	Discharges by Major Steam Electric Powerplants, lb/day	Percentage of All Major Dischargers
Chromium	15,365	50
Copper	2,739	14
Iron	20,683	10
Zinc	20,099	21
Total	58,886	14

Table A-V-14

Total Iron and Copper Discharges from Coal-Fired Powerplants in the U.S. (1973)

Source	Iron, lb/day	Copper, lb/day
Ash Ponds	10,200	180
Boiler Cleaning	1,500	150
Condenser Cleaning	-	40
Total	11,700	370

Total suspended solids in waste water streams from a typical 1,000 megawatt coal-fired plant are as follows:

Low-volume wastes	500 lb/day
Coal-pile runoff	500 lb/day
Ash sluicing	1,240,000 lb/day

A conventional ash pond for a 1,000 megawatt coal-fired plant achieving an average effluent total suspended solids concentrations of 30 mg/l and using 10,000,000 gallons per day of sluice water would discharge 2,650 lb/day of total suspended solids.

Summary of Chemical Usage

Table A-V-15 lists chemicals used in steam electric powerplants corresponding to various classes of uses. Table A-V-16, from the U.S. Atomic Energy Commission document, "Toxicity of Power Plant Chemicals to Aquatic Life," lists chemicals specifically associated with nuclear powerplants and includes some chemicals not included in Table A-V-15.[462] Table A-V-17 gives the annual use of high tonnage chemical additives by powerplants. Table A-V-18 gives chemical compositions of trade-name microorganism control chemicals.

Classification of Waste Waters Sources

Waste water sources can be classified as high-volume, intermediate-volume, low-volume, or rainfall run-off. Table A-V-19 lists the individual waste water sources according to the above classification.

The available data on waste water flow rates corresponding to the various waste water sources in steam electric powerplants are summarized in Table A-V-20 along with typical concentrations of major pollutants.

Table A-V-15

CHEMICALS USED IN STEAM ELECTRIC POWERPLANTS
Major source is Reference 21.

Use	Chemical
Coagulant in clarification water treatment	Aluminum sulfate
	Sodium aluminate
	Ferrous sulfate
	Ferric chloride
	Calcium carbonate
Regeneration of ion exchange water treatment	Sulfuric acid
	Caustic soda
	Hydrochloric acid
	Common salt
	Soda ash
	Ammonium hydroxide
Lime soda softening water treatment	Soda ash
	Lime
	Activated magnesia
	Ferric coagulate
	Dolomitic lime
Corrosion inhibition or scale prevention in boilers	Disodium phosphate
	Trisodium phosphate
	Sodium nitrate
pH control in boilers	Ammonia
	Cyclohexylamine
Sludge conditioning	Tannins
	Lignins
	Chelates such as EDTA,NTA
Oxygen scavengers in boilers	Hydrazine
	Morphaline
Boiler cleaning	Hydrochloric acid
	Citric acid
	Formic acid
	Hydroxyacetic acid
	Potassium bromate
	Phosphates
	Thiourea
	Hydrazine
	Ammonium hydroxide
	Sodium hydroxide
	Sodium carbonate
	Nitrates
Regenerants of ion exchange for condensate treatment	Caustic soda
	Sulfuric acid
	Ammonex

Use	Chemical
Corrosion inhibition or scale prevention in cooling towers	Organic phosphates
	Sodium phosphate
	Chromates
	Zinc salts
	Synthetic organics
Biocides in cooling towers	Chlorine
	Hydrochlorous acid
	Sodium hypochlorite
	Calcium hypochlorite
	Organic chromates
	Organic zinc compounds
	Chlorophenates
	Thiocyanates
	Organic sulfurs
pH control in cooling towers	Sulfuric acid
	Hydrochloric acid
Dispersing agents in cooling towers	Lignins
	Tannins
	Polyacrylonitrile
	Polyacrylamide
	Polyacrylic acids
	Polyacrylic acid salts
Biocides in condenser cooling water systems	Chlorine
	Hypochlorites
Additives to house service water systems	Chlorine
	Chromates
	Caustic soda
	Borates
	Nitrates
Additives to primary coolant in nuclear units	Boric acid
	Lithium hydroxide
	Hydrazine
Numerous uses	Numerous proprietary chemicals

Table A-V-16

CHEMICALS ASSOCIATED WITH NUCLEAR POWER PLANTS

Reference: U.S. Atomic Energy Commission report "Toxicity of Power Plant Chemicals to Aquatic Life"

CORROSION & SCALE INHIBITORS

Chromates

Sodium chromate
Sodium dichromate
Zinc chromate
Zinc dichromate
Potassium chromate
Potassium dichromate

Phosphates and Polyphosphates

Calcium metaphosphate
Sodium phosphate
Sodium metaphosphate
Sodium hexametaphosphate
Sodium tripolyphosphate
Sodium pyrophosphate
Zinc phosphate
Sodium orthophosphate
Calcium phosphate

Organic polyphosphates

Glassy Silicates

Sodium silicate

Nitrites and Nitrates

Sodium nitrite
Sodium nitrate
Potassium nitrate

Cyanates

Sodium ferrocyanate

Fluorides

Sodium fluoride

Amines (also used as biocides)

Octadecylamine
Ethylenediamine
Cyclohexylamine
Benzylamine
Morphine

Chelating Agents

Ethylenediamine Tetraacetic acid (EDTA)
Nitrilotriacetic acid (NTA)
LTSR - "low temperature scale remover"
(a proprietary compound produced by Dow Chemical)

CLEANING & NEUTRALIZING COMPOUNDS

Alkaline Cleaning Stage

Sodium hydroxide
Calcium hydroxide
Sodium phosphate
Sodium sulfate

Sodium triphosphate
Ammonium hydroxide

Acid Cleaning Stage

Citric acid
Sulfuric acid

Neutralizing (Passivating) Stage

Sodium carbonate
Sodium sulfate
Sodium phosphate
Sodium diphosphate
Sulfuric acid
Lithium hydroxide
Morpholine
Sodium lignosulfonate
Cyclohexylamine
Ammonium sulfate
Ammonium hydroxide
Ammonia

Oxygen Reducers

Hydrazine
Morpholine
Sodium sulfite
Cobalt sulfate
Cobalt

Reactivity Control

Boric acid
Boron

BIOCIDES (particularily cooling tower use)

Oxidizing Biocides

Chlorine
Bromine
Sodium hypochlorite
Calcium hypochlorite
Potassium permanganate
Chlorinated cyanurates and inocyanurates

Persulfate Compounds

Potassium hydrogen persulfate

Non - oxidizing Biocides

1. Chlorinated and/or phenylated phenols:
    - Chloro-O-phenylphenol
    - 2-Tert-Butyl-4-chloro-5-methylphenol
    - O-Benzyl-p-chlorophenol
    - 4,6-Dichlorophenol
    - 2,4-Dinitrochlorobenzene
    - 2,6-Dinitrochlorobenzene
    - 2,4,5-Trichlorophenol
    - 1,3-Dichloro-5,5-Dimethylhydranotin
    - Trichloromethyl sufone (Bis)
    - Sodium salts (ates) of:
        - O-Phenylphenol
        - 2,4,5-Trichlorophenol (sodium 2,4,5-Trichlorophenate)
        - Chloro-2,phenylphenol
        - 2-Chloro-4-phenylphenol
        - 2-Bromo-4-phenylphenol
        - 2,3,4,6-Tetrachlorophenol
        - Pentachlorophenol
    - Potassium salts (ates) of:
        - 2,4,5-Trichlorophenol
2. Quaternary Amines (quaternary ammonium compounds)
    - Dilauryl dimethyl ammonium chloride
    - Dilauryl dimethly ammonium oleate
    - Dodecyl trimethyl ammonium chloride
    - Trimethyl ammonium chloride
    - Octadecyl trimethyl ammonium chloride
    - N-Alkyl benzyl-N,N,N,-trimethyl ammonium chloride
    - Alkyl-9-methyl benzyl ammonium chloride
    - Lactory mercuriphenyl ammonium lactate
    - Alkyl dimethyl benzyl ammonium chloride
    - 3,4-Dichloro benzyl ammonium chloride
    - Phenylmercuric trihydroxyethyl ammonium lactate
    - Phenylmercuric triethanol ammonium lactate
    - Alkyl (C_{12} to C_{18}) dimethyl benzyl-ammonium chlorides
    - 1-Alkyl (C_6 to C_{18}) amino-3 aminopropane monoacetate
3. Organo-metallic Compounds
    - Organotins
        - Bis (Tributyl Tin) oxide
    - Organosulfurs
    - Disulfides
    - Organothiocyanates
    - Methylene bisthiocyanate
4. Cationic Surface Active Agents
    - Sulfonium
    - Phosphonium
    - Arsonium
    - Iodonium
5. Dithiocarbamic Acid Salts
    - Sodium dimethyl diethyl dithiocarbamate
    - Disodium ethylene bisdithiocarbamate
6. Organic Amines (often used with pentachlorophenol)
    - Primary Rosin Amines
        - Sodium carboxethyl rosin amine
        - Rosin amine acetate
    - Other Amines (primary beta-amines and beta-diamines)
        - Chloramine
        - :
        - Benzylamine
        - Cyclohexylamine
        - Ethylenediamine
        - Polyethyleneamine

Zinc and Copper Salts

Zinc sulfate
Copper sulfate
Copper citrate

Acrolein
Arsenates
Arsenic acid
Sodium arsenite

CORROSION PRODUCTS

Copper Ions
Zinc ions

Inorganic Scale and Precipitates

Calcium carbonate
Calcium phosphate
Calcium sulfate
Calcium hydroxide
Magnesium carbonate
Magnesium hydroxide
Magnesium phosphate
Iron oxides

Table A-V-17

Use of High Tonnage Chemical Additives by Steam Electric Powerplants (1970)[461]

Chemical	Cooling Water Additive, tons	Boiler Water Additive, tons	**Total, tons**
Alum	2,470	1,751	3,221
Caustic Soda	-	37,998	37,998
Chlorine	24,642	985	25,627
Lime	13,324	7,824	21,148
Phosphate	865	1,100	1,965
Total	41,301	49,658	90,959

Table A-V-18 **Chemical composition of trade-name microorganism control chemicals**

Chemical	Composition (%)	Usage
NALCO 21-S		Periodically, as needed, 25–400 ppm or continuously
Sodium pentachlorophenate	21.3	
Sodium 2,4,5-trichlorophenate	11.9	
Sodium salts of other chlorophenols	3.0	
Inert ingredients	63.8	
NALCO 25-L or NALCO 425-L		Weekly, 20–300 ppm
1-Alkyl (C_6 to C_{18})-amino-3-aminopropane propionate–copper acetate complex	15.0	
Isopropyl alcohol	30.0	
Copper expressed as metallic	0.55	
Inert ingredients	55.0	
NALCO 201		Periodically, as needed, 300-400 ppm or 12 60 ppm continuously
Potassium pentachlorophenate	15.7	
Potassium 2,4,5-trichlorophenate	9.0	
Potassium salts of other chlorophenols	1.8	
Inert ingredients	70.3	
NALCO 202		5–200 ppm periodically or continuously
Methyl-1,2-dibromopropionate	29.7	
Inert ingredients	70.3	
NALCO 207		Weekly, 25-50 ppm
Methylene bisthiocyanate	10.0	
Inert ingredients	90.0	
NALCO 209		As needed, 50–100 ppm
1,3-Dichloro-5,5-dimethylhydantoin	25.0	
Inert ingredients	75.5	
NALCO 321		Weekly, 5–200 ppm
1-Alkyl (C_8 to C_{18})[a] amino-3-aminopropane monoacetate	20.0	
Isopropyl alcohol	30.0	
Inert ingredients	50.0	
NALCO 322		As needed, 10-200 ppm
1-Alkyl (C_6 to C_{18})[a] amino-3-aminopropane monoacetate	19.8	
2,4,5-Trichlorophenol	9.5	
Isopropyl alcohol	27.0	
Inert ingredients	43.7	
NALCO 405		As needed, 100-200 ppm
2,4-Dinitrochlorobenzene	22.2	
2,6-Dinitrochlorobenzene	2.8	
Inert ingredients	75.0	
Betz A-9		
Sodium pentachlorophenate	24.7	
Sodium 2,4,5-trichlorophenate	9.1	
Sodium salts of other chlorophenates	2.9	
Sodium dimethyl dithiocarbamate	4.0	
N-Alkyl (C_{12} – 4%, C_{14} – 50%, C_{16} – 10%) dimethylbenzylammonium chloride	5.0	
Inert ingredients (including solubilizing and dispersing agents)	54.3	
Betz C-5		
1,3-Dichloro-5,5-dimethylhydantoin	50	
Inert ingredients (including solubilizing and dispersing agents)	50	
Betz C-30		
Bis(trichloromethyl) sulfone	20.0	
Methylene bisthiocyanate	5.0	
Inert ingredients (including solubilizing and dispersing agents)	75.0	
Betz C-34		
Sodium dimethyl dithiocarbamate	15.0	
Nabam (disodium ethylene bisdithiocarbamate)	15.3	
Inert ingredients (including solubilizing and dispersing agents)	69.7	
Betz J-12		
N-Alkyl (C_{12} – 5%, C_{14} – 60%, C_{16} – 30%, C_{18} – 5%) dimethylbenzylammonium chloride	24.0	
Bis(tributyltin) oxide	5.0	
Inert ingredients (including solubilizing and dispersing agents)	71.0	
Betz F-14		
Sodium pentachlorophenate	20.0	
Sodium 2,4,5-trichlorophenate	7.5	
Sodium salts of chlorophenate	2.5	
Dehydroabutyl ammonium phenoxide	2.0	
Inert ingredients, including dispersants	68.0	

[a] As in fatty acids of coconut oil.

From company sources and Environmental Protection Agency.

Table A-V-19

CLASS OF VARIOUS WASTE WATER SOURCES

Class	Source
High Volume	Nonrecirculating main condenser cooling water
Intermediate Volume	Nonrecirculating house service water Blowdown from recirculating main cooling water system Nonrecirculating ash sluicing systems Nonrecirculating wet-scrubber air pollution control systems
Low Volume	Clarifier water treatment Softening water treatment Evaporator water treatment Ion exchange water treatment Reverse osmosis water treatment Condensate treatment Boiler blowdown Boiler tube cleaning Boiler fireside cleaning Air preheater cleaning Stack cleaning Miscellaneous equipment cleaning Recirculating ash sluicing systems Recirculating wet-scrubber air pollution control systems Intake screen backwash Laboratory and sampling streams Cooling tower basin cleaning Rad wastes Sanitary system Recirculating house service water Floor drainage Miscellaneous streams
Rainfall Runoff	Coal pile drainage Yard and roof drainage Construction activities

Table A-V-20

TYPICAL CHEMICAL WASTES FROM A COAL-FIRED POWERPLANT

Waste Stream	Flow,[1] GPD/Mw	Typical Concentrations of Major Pollutants[1], mg/l				
		TSS	Iron	Copper	Sulfate	Hardness
Ion exchange	88	46	-	-	2085	-
Boiler blowdown	52	25	-	-	-	-
Boiler cleaning	0.25	127	2100	380	-	520
Boiler fireside cleaning	4.44	582	142	-	1650	4661
Air preheater cleaning	11.7	1882	1610	-	1130	3700
Miscellaneous cleaning	1.11	1000[2]	-	-	-	-
Laboratory operations	10	100[2]	-	-	-	-
Floor drains	30	100[2]	-	-	-	-
Recirculating bottom ash sluicing blowdown	400	1000[2]	-	-	-	-
Ash pond overflow (once-through fly ash)	5000	60	-	-	510	244
Coal pile drainage	-[3]	864	-	-	6880	1025

Notes: 1. Based on the average of available data
2. Assumed values
3. Based on 0.02 acres/Mw coal pile and 40 inches of rainfall per year; the flow is calculated to be 59,500 GPD for a 1000 Mw plant

PART A

CHEMICAL WASTES

SECTION VI

SELECTION OF POLLUTANT PARAMETERS

Definition of Pollutants

Section 502(6) defines the term "pollutant" to mean dredged spoil, solid waste, incinerator residue, sewage, garbage, radioactive materials, heat, wrecked or discarded equipment, rock, sand, cellar dirt and industrial, municipal and agricultural waste discharged into water. This report addresses all pollutants discharged from steam electric powerplants with the exception of both high-level and low-level radioactive wastes of nuclear powerplants. The exclusion is made for two reasons: (1) administratively, the permiting or licensing authority for nuclear plants, from the standpoint of radiation safety resides with the U.S. Atomic Energy Commission; and (2) it is not known that the application of conventional waste water treatment technology for the control of non-radiation aspects of radioactive waste will not result in the creation of a radiation hazard (e.g. due to the concentration of the suspended solids removed).

Introduction

Section A-V describes various operations in a steam electric powerplant which give rise to chemical wastes. Reported data were included for each waste stream wherever available. The waste streams are specific to each powerplant and depend upon factors such as raw water quality, type and size of plant, age of plant, ambient conditions and operator preferences. Table A-VI-1 summarizes the pollutants present in the various chemical waste streams based on data recorded in Section A-V, Waste Characterization, and knowledge of the respective processes. The data in many cases show a wide variation from plant to plant. This wide variation in data and the presence of many pollutants in a single waste stream makes the selection of characteristic pollutants a difficult task. Table A-VI-2 summarizes the number of plants for which data was recorded in Section A-V for each waste stream.

TABLE A-VI-1

APPLICABILITY OF PARAMETERS TO CHEMICAL WASTE STREAMS

	Condenser Cooling System		Water Treatment				Chemical Cleaning								
PARAMETER	Once Through	Recircu-lating	Clarifi-cation Wastes	Ion Ex-change Wastes	Evaporator	Boiler Blowdown	Boiler Tubes	Air Pre-heater	Boiler Fireside	Ash Pond Overflow	Coal Pile Drainage	Floor Drains	Air Pollution Devices SO_2 Removal	Sanitary Wastes	Low Rad Wastes
ALKALINITY	X	X	X	X	X	X	X	X	X	X			X		
BOD		X	X	X	X	X	X	X		X		X	X	X	
COD		X	X	X	X	X	X	X	X	X		X		X	
TS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
TDS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
TSS		X	X	X	X	X	X	X	X	X	X	X	X	X	
AMMONIA		X	X	X	X	X	X	X	X	X	X			X	
NITRATE		X	X	X	X	X	X			X	X			X	
PHOSPHOROUS		X	X	X	X	X	X			X	X		X	X	
TURBIDITY		X	X		X	X	X	X	X	X	X	X	X	X	
FECAL COLIFORM														X	
ACIDITY							X	X	X	X	X	X	X		
HARDNESS, TOTAL		X	X	X	X	X	X			X		X	X		
SULFATE		X	X	X	X	X	X	X	X	X	X	X	X		
SULFITE								X	X	X		X	X		
BROMIDE							X								
CHLORIDE		X	X		X	X	X	X	X	X	X			X	
FLUORIDE		X	X	X			X			X					
ALUMINUM		X	X		X	X	X		X	X	X		X		
BORON															X
CHROMIUM		X	X	X	X	X	X	X	X	X	X				
COPPER	X	X	X	X	X	X	X	X	X	X	X				
IRON		X	X	X	X	X	X	X	X	X	X		X		
LEAD										X	X	X			
MAGNESIUM		X	X	X	X	X	X	X	X	X	X	X	X		
MERCURY				X	X		X			X	X				
NICKEL		X	X	X	X	X	X	X	X	X	X				
SELENIUM							X			X	X				
VANADIUM									X	X			X		
ZINC		X	X	X	X	X	X			X	X				
OIL & GREASE				X			X			X		X	X		
PHENOLS		X	X		X					X	X				
SURFACTANTS					X		X			X		X		X	
ALGICIDES	X	X												X	
CHLORINE	X	X													
MANGANESE		X		X	X	X	X		X	X	X		X		

NOTE: Miscellaneous streams such as laboratory sampling, stack chemical cleanings, etc. are not included since the species are accounted for in other streams.

TABLE A-VI-2

CHEMICAL WASTES-

NUMBER OF PLANTS WITH RECORDED DATA

PARAMETER	Condenser Cooling System Once Through	Condenser Cooling System Recirculating	Water Treatment Clarification Wastes	Water Treatment Ion Exchange Wastes	Water Treatment Evaporator	Boiler Blowdown	Chemical Cleaning Boiler Tubes	Chemical Cleaning Air Preheater	Chemical Cleaning Boiler Fireside	Ash Pond Overflow	Coal Pile Drainage	Floor Drains	Air Pollution Devices SO_2 Removal	Sanitary Wastes	Low Rad Wastes
ALKALINITY	-	6	5	12	5	17	6	7	2	27	9	3	1	-	-
BOD	-	4	4	12	7	18	6	7	2	-	4	3	-	-	-
COD	-	4	5	12	7	17	6	7	2	-	5	3	-	-	-
TS	-	4	6	16	8	17	6	7	2	28	6	3	-	-	-
TDS	-	6	6	18	9	18	6	6	2	26	7	3	1	-	-
TSS	-	5	6	16	8	17	6	7	2	26	7	3	1	-	-
AMMONIA	-	5	5	15	7	15	6	7	2	21	5	3	-	-	-
NITRATE	-	6	6	17	7	14	5	7	2	21	5	3	1	-	-
PHOSPHOROUS	-	9	6	20	9	19	17	7	2	18	2	3	1	-	-
TURBIDITY	-	-	6	7	5	10	6	7	2	12	3	3	-	-	-
FECAL COLIFORM	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ACIDITY	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-
HARDNESS, TOTAL	-	6	6	15	7	11	4	7	2	19	4	-	1	-	-
SULFATE	1	11	6	23	7	16	5	7	2	27	8	1	2	-	-
SULFITE	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-
BROMIDE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CHLORIDE	2	10	6	21	8	17	17	7	2	25	4	3	-	-	-
FLUORIDE	-	2	-	-	-	-	10	-	-	-	-	-	-	-	-
ALUMINUM	-	1	1	-	-	-	11	-	-	12	2	-	1	-	-
BORON	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CHROMIUM	-	4	5	14	8	11	15	7	2	12	6	1	1	-	-
COPPER	-	1	4	8	5	7	17	5	1	7	4	-	1	-	-
IRON	-	5	5	13	5	8	17	7	2	16	7	-	-	-	-
LEAD	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-
MAGNESIUM	-	6	5	17	6	6	13	7	2	15	2	-	1	-	-
MERCURY	-	-	-	2	2	-	-	-	-	2	-	-	-	-	-
NICKEL	-	1	2	5	2	5	14	7	1	4	-	-	1	-	-
SELENIUM	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VANADIUM	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ZINC	-	5	5	16	8	13	17	7	2	16	7	1	-	-	-
OIL & GREASE	-	-	-	2		-	-	-	-	-	-	1	-	-	-
PHENOLS	-	2	-	5	3	5	-	-	-	-	-	1	-	-	-
SURFACTANTS	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-
ALGICIDES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CHLORINE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MANGANESE	-	3	-	4	2	-	12	-	-	5	-	-	-	-	-

Common Pollutants

Since powerplant waste effluents are primarily due to inorganic chemicals, the common pollutants reflect the general level of inorganic chemical concentration.

pH Value

pH value indicates the general alkaline or acidic nature of a waste stream, and represents perhaps the most significant single criteria for the assessment of its pollutional potential. While a pH in the neutral range between 6.0 and 9.0 does not by itself assure that the waste stream does not contain detrimental pollutants, a pH outside of this range is an immediate indication of the presence of potential pollutants.

Total Dissolved Solids

Total dissolved solids represents the residue (exclusive of total suspended solids) after evaporation and includes soluble salts such as sulfates, nitrates, chlorides, and bromides. Total dissolved solids are particularly significant as a pollutant in discharges from closed systems which involve recirculation and re-use. These systems tend to concentrate dissolved solids as a result of evaporation and require blowdown to maintain dissolved solids within ranges established by process requirements. The blowdown may contain specific pollutants in detrimental amounts depending on the number of cycles of concentration.

Total Suspended Solids

Total suspended solids is another pollutant which is a characteristic of all the waste streams. Suspended solids are significant as an indicator of the effectiveness of solids separation devices such as mechanical clarifiers, ash ponds, etc. One of the functions of water use in a powerplant is to convey solids from one stage of the process to another or to a point of final disposal. Some processes used in a powerplant create suspended solids by chemically treating compounds in solution so that they become insoluble and precipitate. Turbidity is related to suspended solids but is a function of particle size and not an independent pollutant.

Having established the three common pollutants, the characteristic pollutants of individual waste streams are outlined below.

Pollutants from Specific Waste Streams

Biochemical Oxygen Demand (BOD)

BOD is a significant pollutant only for sanitary waste water originating from the use of sanitary facilities by plant personnel.

Chemical Oxygen Demand (COD)

COD is a pollutant usually attributed to the organic fraction of industrial waste waters. Since steam electric powerplants do not have a significant volume of organic wastes, COD is generally not a significant pollutant in powerplant effluents, but may be used as gross indicator for certain combined wastes.

Oil and Grease

Oil and grease enter the plant drainage system primarily as a result of spillage and subsequent washdown during housekeeping operations or following natural precipitation. Oil and grease are also removed from equipment during pre-operational cleaning. Oil and grease is normally present in the following waste streams:

Chemical cleaning - boiler tubes;
- boiler fireside;
- air preheater;
- miscellaneous small equipment;

Ash handling wastes - oil fired plants;
- coal fired plants;

Drainage and misc. waste streams - floor and yard drains;
- closed cooling water systems; and
- construction activity.

Ammonia

Ammonia is a significant pollutant in plants that use ammonia compounds in their operations. Ammonia may be used to control the pH in the boiler feedwater. It may also be used for ion exchange regeneration in condensate polishing and in boiler cleaning. An ammonia derivative, hydrazine, is used as an oxygen scavenger, but is used only in small quantities. Because of its instability, it is not likely to be a component of a waste stream. Ammonia will therefore be a component of those waste streams which emanate from the operations during which ammonia is added to the system, such as ion exchange wastes, boiler blowdown, boiler tube cleaning and closed cooling water systems.

Total Phosphorus

Phosphates are used by some powerplants in recirculating systems to prevent scaling on heat transfer surfaces. To the extent that they are used, they will be a component of any blowdown from such systems. These include primarily boiler and PWR steam generator blowdown and blowdown from closed cooling water systems but could also include a number of minor auxiliary systems. In some cases, phosphorus compounds are also used in boiler cleaning operations and would therefore be a possible component of cleaning wastes.

Chlorine Residuals

Many condenser cooling water systems use chlorine or hypochlorites to control biological growth on the inside surface of condenser tubes. The biological growth, if left uncontrolled, causes excessive tube blockages, poor heat transfer, and accelerated system corrosion--all of which reduce plant efficiency. For any cooling tower system the length of time of the chlorine feed period and the number of chlorine feed periods per day, week, or month change as the biological growth situation changes. In most cooling systems, the chlorine is added at or near the condenser inlet in sufficient quantity to produce a free available chlorine level of 0.1-0.6 mg/l in the water leaving the condenser. The amounts of chlorine added to maintain the free available chlorine depend upon the amount of chlorine demand agents and ammonia in the water.

Chlorine and ammonia react to form chloramines. Chloramines contribute to the combined residual chlorine of the water. The combined residual chlorine is less efficient and slower in providing biological control than is the free available chlorine. Total residual chlorine is the sum of the free available chlorine and the combined residual chlorine.

Although chlorination is effective for slime control in condenser tubes of cooling system, its application may result in the discharge of total residual chlorine to the receiving water. The effects of total residual chlorine on aquatic life are of great concern.

Metals

Various metals may be contained in some of the waste streams as a result of corrosion and erosion of metal surfaces and as soluble components of the residues of combustion where such residues have been handled hydraulically.

Blowdown from boiler feedwater systems and from closed cooling water systems will contain trace amounts of the metals making up the heat exchanger surfaces with which they have been in contact. Treatment of these waters generally minimizes the amount of corrosion. However, cleaning operations of these systems are designed specifically to restore the heat transfer surfaces to bare metal. In this process significant amounts of metal and metal oxide are dissolved and are conveyed with the waste streams. The two most common metals likely to be present in cleaning wastes are iron and copper.

Metals present in wastes from fuel storage and from ash handling operations will depend on the metals present in the fuel. Generalization is difficult because of the wide variation in fuel composition, but iron and aluminum are typically present in significant quantities in ash from coal. Mercury may be present if the coal used contained mercury. Vanadium is present in sufficient quantities in ash resulting from the burning of some types of residual fuel oil, notably of Venezuelan origin.

If chromates and/or zinc compounds are used for the treatment of closed cooling water systems, chromium and/or zinc will be significant pollutants for any blowdown or leakage from these systems.

These metals are likely to occur in the following waste streams:

1. Iron

   water treatment - clarification;
   maintenance cleaning - boiler tubes;
   - boiler fireside;
   - air preheater;
   ash handling - coal fired plants;
   and coal pile drainage.

2. Copper

   boiler and steam generator (PWR) blowdown;
   chemical cleaning - boiler tubes;
   - air preheater;
   - boiler fireside
   condenser cooling water systems - once through; and recirculating

3. Mercury

ash handling - coal fired plants; and coal pile drainage.

4. Vanadium (oil-fired plants only)

ash handling;
chemical cleaning - boiler fireside; and
- air preheater.

5. Chromium and Zinc

recirculating condenser cooling system; and closed cooling water system.

6. Aluminum and Zinc

coal pile drainage;
ash handling - coal fired plants;
water treatment - clarification;
chemical cleaning - boiler fireside; and
- air preheater.

Phenols

Polychlorinated biphenyls (PCB's) are sometimes used as coolants in large transformers. PCB's may also be used as heat transfer fluids and for other purposes. In case of leaks or spills, these materials could find their way into the yard drainage system. Materials showing up as phenols are also possible in drainage from coal piles, floor and yard drainage, ash handling streams, and cooling tower blowdown.

Sulfate

Sulfates in powerplant effluents arise primarily from the regenerant wastes of ion exchange processes. Sulfate may occur in ion exchange and evaporator wastes, boiler fireside and air preheater cleaning, ash handling and coal pile drainage.

Sulfite

Sulfite is used as an oxygen scavenger in the boiler feedwater system in some plants. Plants using sulfite may discharge the sulfite with their boiler blowdown. Because of its high oxygen demand, sulfite in significant quantities is considered undesirable in a plant discharge.

Sulfite may occur in the following waste streams:

maintenance cleaning - boiler fireside;
- air preheater;
- stack;
- cooling tower basin;

ash handling - oil fired plants;
- coal fired plants;

coal pile drainage;and
air pollution control
devices for SO_2 removal.

Boron

Oxidizing agents such as potassium or sodium borate may be contained in cleaning mixtures used for copper removal in the chemical cleaning of boiler and steam generator (PWR) tubes.

Fluoride

Hydrofluoric acid or fluoride salts are added for silica removal in the chemical cleaning of boiler and steam generator (PWR) tubes.

Alkalinity and Acidity

Both alkalinity and acidity are parameters which are closely related to the pH of a waste stream.

Total Solids

Total solids is the sum of the total suspended solids and the total dissolved solids.

Fecal Coliform

Fecal coliform is only significant in sanitary waste.

Total Hardness

Hardness is a constitutent of natural waters, and as such is not generally considered as a pollutant in effluents from industrial processes. Also, hardness is not harmful in the concentrations recorded in Section A-V.

Chloride and Magnesium

Both chloride and magnesium are not practicably treatable at the levels recorded, and also are not harmful at the levels present in the various waste streams.

Bromide

Bromide may result from boiler cleaning operations, but is not considered harmful at the levels present. Moreover, it is not practicably treatable at these levels.

Nitrate and Manganese

Nitrate and manganese are also not harmful nor practicably treatable at the levels present in the various waste streams.

Surfactants

Surfactants are not practicably treatable at the recorded levels.

Algicides

Very little data was found for algicides (exclusive of chlorine) although various algicides may be utilized in cooling water systems. Most utilities requiring algicides utilize chlorine.

Other Potentially Significant Pollutants

The following are potentially significant pollutants, which may be present in effluents from steam electric powerplants, but for which little data are available at this time.

Cadmium
Lead
Nickel
Selenium

Complete analyses of the fossil fuel used by a particular plant can be used as a basis for determining which pollutants, in addition to those covered by effluent limitations guidelines and standards, are likely to be present in effluents in quantities justifying monitoring and the establishment of effluent limitations.

Selection of Pollutant Parameters

The U. S. Environmental Protection Agency published (Federal Register, Volume 38, No. 199, pp. 28758-28670, October 16, 1973) 40 CFR 136 "Guidelines Establishing Test Procedures for the Analysis of Pollutants." Seventy-one pollutant parameters were covered. This list with the addition of free available chlorine, polychlorinated biphenyls, chemical additives, debris and pH, which were not included, provides the basis for the selection of pollutant parameters for the purpose of developing effluent limitations guidelines and standards. All listed parameters are selected except for these excluded for one or more of the following reasons:

1. Not harmful when selected parameters are controlled
2. Not present in significant units
3. Not controllable
4. Control substitutes more harmful pollutant
5. Insufficient data available
6. Indirectly controlled when selected parameters are controlled.
7. Indirectly measured by another parameter
8. Radiological pollutants not within the scope of effluent limitations guidelines and standards.

Table A-VI-3 presents a breakdown of the methodology for selection of parameters for the following waste water stream (except for sanitary wastes) which comprise the entire waste water discharged from steam electric powerplants:

High Volume

- nonrecirculating (once-through) condenser cooling systems

Intermediate Volume

- blowdown from recirculating condenser cooling water systems
- nonrecirculating ash sluicing systems;
- nonreciruclating service water systems

Table A-VI-3

SELECTION OF POLLUTANT PARAMETERS*

POLLUTANT PARAMETER	CLASS OF WASTE WATER STREAMS			
	High-Volume	Intermediate-Volume	Low-Volume	Rainfall Runoff
General				
Acidity (as $CaCO_3$)	1	1	1	1
Alkalinity (as $CaCO_3$)	1	1	1	1
Ammonia (as N)	2	2	2	2
Biochemical oxygen demand (5-day)	2	2	2	2
Chemical oxygen demand	2	2	2	2
Hardness-total	3	4	4	4
Kjeldahl nitrogen (as N)	2	2	2	2
Nitrate (as N)	2	2	2	2
Nitrite (as N)	2	2	2	2
pH value	2	●	●	●
Total dissolved (filterable) solids	3	3	6	3
Total organic carbon	2	2	2	2
Total phosphorus (as P)	2	●	6	2
Total solids	3	6	6	6
Total suspended (nonfilterable) solids	3	●	●	●
Total volatile solids	2	2	2	2
Nutrients, Anions, and Organics				
Algicides	6	6	5	2
Benzidine	2	2	2	5
Bromide	2	3	3	3
Chloride	3	3	3	3
Chlorinated organic compounds	2	5	5	5
Chlorine-free available	●	●	2	2
Chlorine-total residual	6 **	6 **	2	2
Cyanide-total	2	2	2	2
Debris	●	2	2	2
Flouride	2	2	6	2
Oil and grease	2	●	●	●
Organic nitrogen (as N)	2	2	2	2
Ortho-phosphate (as P)	2	6	6	2
Pesticides	2	5	2	5
Phenols	2	2	2	2
Polychlorinated biphenyls	2	2	2	●
Sulfate (as SO_4)	3	3	3	3
Sulfide (as S)	3	3	3	3
Sulfite (as SO_3)	3	3	3	3
Surfactants	2	6	6	2
Chemical additives (biocide,corr.inhib.)	6**	6**	6	2

*Key: ● =Selected
1 =Rejected because not harmful when selected parameters are controlled
2 =Rejected because not present in significant amounts
3 =Rejected because not controllable
4 =Rejected because control substitutes a more harmful pollutant
5 =Rejected because insufficient data available
6 =Rejected because indirectly controlled when selected parameters are controlled
7 =Rejected because indirectly measured by another parameter
8 =Rejected because radiological pollutants are not within the scope of E.P.A. guidelines and standards

** Selected where technology is available to achieve no discharge

Table A-VI-3 (continued)

SELECTION OF POLLUTANT PARAMETERS *

POLLUTANT PARAMETER	CLASS OF WASTE WATER STREAMS			
	High-Volume	Intermediate-Volume	Low-Volume	Rainfall Runoff
Trace Metals				
Aluminum-total	2	6	6	6
Antimony-total	2	2	2	2
Arsenic-total	2	2	2	2
Barium-total	2	2	2	2
Beryllium-total	2	2	2	2
Boron-total	2	3	3	3
Cadmium-total	2	3	2	2
Calcium-total	1	1	1	1
Chromium-VI	2	6	6	2
Chromium-total	2	●	6	2
Cobalt-total	2	2	2	2
Copper-total	3	6	●	2
Iron-total	3	6	●	2
Lead-total	2	2	2	2
Magnesium-total	1	1	1	1
Manganese-total	2	2	2	2
Mercury-total	2	2	2	2
Molybdenum-total	2	2	2	2
Nickel-total	3	6	6	6
Potassium-total	1	1	1	1
Selenium-total	2	2	2	2
Silver-total	2	2	2	2
Sodium-total	1	1	1	1
Thallium-total	2	2	2	2
Tin-total	2	2	2	2
Titanium-total	2	2	2	2
Vanadium-total	2	2	2	2
Zinc-total	2	●	6	2
Physical and Biological				
Coliform bacteria (fecal)	2	2	2	2
Coliform bacteria (total)	2	2	2	2
Color	2	6	6	6
Fecal streptococci	2	2	2	2
Specific conductance	2	7	7	7
Turbidity	3	6	6	6
Radiological				
Alpha-counting error	8	8	8	8
Alpha-total	8	8	8	8
Beta-counting error	8	8	8	8
Beta-total	8	8	8	8
Radium-total	8	8	8	8

*Key ● =Selected
1 =Rejected because not harmful when selected parameters are controlled
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5 =Rejected because insufficient data avialable
6 =Rejected because indirectly controlled when selected parameters are controlled
7 =Rejected because indirectly measured by another parameter
8 =Rejected because radiological pollutants are not within the scope of E.P.A. guidelines and standards

- nonrecirculating wet-scrubbing air pollution control systems

Low Volume

- blowdown from recirculating ash sluicing systems
- blowdown from recirculating wet-scrubber air pollution control systems
- boiler blowdown
- equipment cleaning (air preheater, boiler fireside, boiler tubes, stack, etc.)
- evaporator blowdown
- flow drains
- intake screen backwash
- recirculating service water systems
- water treatment system

Rainfall Runoff

- coal pile drainage
- road and yard drains
- construction activities

Sanitary System

The selected parameters for the various classes of waste water streams are shown in Table A-VI-4.

Environmental Significance of Selected Pollutant Parameters

The environmental significance of many of the pollutant parameters evaluated in this section are discussed in detail in "Water Quality Criteria 1972," a report of the Committee on Water Quality Criteria, Environmental Studies Board, National Academy of Sciences/National Academy of Engineering, published in 1972 at the request of and funded by the U.S. Environmental Protection Agency. The report addresses the several parameters individually in the light of water quality needs for recreation and aesthetics, public

Table A-VI- 4

SELECTED POLLUTANT PARAMETERS

Class of Waste Water Stream	Parameter
High Volume	Chemical additives (biocides)* Chlorine-free available Chlorine-total residual* Debris
Intermediate Volume	Chemical additives (corrosion inhibitors)* Chlorine-free available Chlorine-total residual* Chromium-total Oil and grease pH value Total phosphorus (as P) Total suspended solids Zinc-total
Low Volume	Copper-total Iron-total Oil and grease pH value Total suspended solids
Rainfall Runoff	Oil and grease pH value Polychlorinated biphenyls Total suspended solids

* Note: Selected where technology is available to achieve no discharge.

water supplies, freshwater and aquatic life and wildlife, agricultural uses, and industrial water supplies.

Briefly summarized below are factors concerning the environmental significance of the pollutant parameters selected in this section.

Iron-Total

Iron is the fourth most abundant, by weight, of the elements that make up the earth's crust. It is common in many rocks and is an important component of many soils, especially the clays where usually it is a major constituent. Iron in water may be present in varying quantities dependent upon the geology of the area and other chemical components of the waterway.

The ferrous, or bivalent (Fe^{++}), and the ferric, or trivalent (Fe^{+++}) irons, are the primary forms of concern in the aquatic environment, although other forms may be in organic and inorganic wastewater streams. The ferrous (Fe^{++}) form can persist only in waters void of dissolved oxygen and originates usually from ground waters or mines when these are pumped or drained. For practical purposes the ferric (Fe^{++}) form is insoluble. Iron can exist in natural organomettallic or humic compounds and colloidal forms. Black or brown swamp waters may contain several parts per million of iron in the presence or absence of dissolved oxygen, but this iron form has little effect on aquatic life because it is complexed or relatively inactive chemically or physiologically.

In stratified lakes with anaerobic hypolimnia, soluble ferrous iron occurs in the deep anaerobic waters. During the autumnal or vernal overturns and with aeration of these lakes, it is oxidized rapidly to the ferric ion that precipitates to the bottom sediments as a hydroxide, $Fe(OH)_3$ or with other anions. If hydrogen sulfide (H_2S) is present in anaerobic bottom waters or muds, ferrous sulfide (FeS) may be formed. Ferrous sulfide is a black compound and results in the production of dark mineral muds.

Prime iron pollution sources are industrial wastes, mine drainage waters, and ironbearing ground waters. In the presence of dissolved oxygen, waters from mine drainage are rapidly precipitated as a hydroxide ($Fe(OH)_3$). These yellowish or ochre precipitates produce "yellow boy" deposits found in many streams draining coal mining regions of Appalachia. Occasionally ferric oxide (Fe_2O_3) is precipitated, which forms red waters. Both of these precipitates form as gels or flocs that may be detrimental when suspended in water to fishes and other aquatic life. They can settle to form flocculant materials that cover stream bottoms thereby destroying bottom-dwelling invertebrates, plants or incubating fish eggs. With time these flocs can consolidate to form cement-like materials, thus consolidating bottom gravels into pavement-like areas that are unsuitable as spawning sites for nest building fishes; particularly this is detrimental to trout and salmon populations whose eggs are protected in the interstices of gravel and incubated with oxygen bearing waters passing through the gravel.

Iron is an objectionable constituent in water supplies for either domestic or industrial use. Iron appreciably affects the taste of beverages and can stain laundered clothes and plumbing fixtures. A study by the Public Health Service indicates that the taste of iron may be readily detected at 1.8 mg/l in spring water and 3.4 mg/l in distilled water.

96 hour LC50 values of 0.32 mg/l of iron have been obtained for mayflies, stoneflies, and caddisflies; all are important fish food organisms. Iron has been found toxic to carp (Cyprinus carpio) at concentrations of 0.9 mg/l when the pH of the waters was 5.5. Pile (Esox lucius) and trout (species not known) died at concentrations of 1-2 mg/l. In an iron polluted Colorado stream, trout or other fish were not found until the waters were diluted or the iron had precipitated to effect a concentration of less than 1.0 mg/l even though other water quality constituents measured were suitable for the presence of trout.

Ferric hydroxide flocs have been observed to coat the gills of white perch (Roccus americanus), minnows and silversides (Menidia sp. ?) The smothering effects of settled iron precipitates may be particularly detrimental to fish eggs and bottom-dwelling fish food organisms. Iron deposits in the Brule River, Michigan and Wisconsin were found to have a residual long term adverse effect on fish food organisms even after the pumping of iron bearing waters from deep shaft iron mines had ceased. Settling iron flocs have also been reported to trap and carry diatoms down from waters.

The effects of iron on marine life have not been investigated adequately to determine a water quality criterion. Soluble iron readily precipitates in alkaline sea waters. Fears have been expressed that these settled iron flocs may have adverse effects on important benthic commercial mussel and other shellfish resources.

Iron has not been reported to have a direct effect on the recreational uses of water other than its effects on aquatic life. Suspended iron precipitates may interfere with swimming and be aesthetically objectionable. Deposits of yellow ochre or reddish iron oxides can be aesthetically objectionable.

Iron at exceedingly high concentrations has been reported to be toxic to livestock and interfere with the metabolism of phosphorus. In aerated soils, iron in irrigation waters are not toxic. Precipitated iron may complex phosphorus and molybdenum making them less available as plant nutrients. In alkaline soils, iron may be so insoluble as to be deficient as a trace element and result in chlorosis, an objectionable plant nutrient deficiency disease.

Polychlorinated Biphenyls

Polychlorinated biphenyls (PCB's) are a class of compounds produced by the chlorination of biphenyls and are known in the United States commercially as Aroclors (R). The degree of chlorination determines their chemical properties and generally their composition can be identified by the numerical nomenclature, e.g., Aroclor 1242, Aroclor 1254, etc. The first two digits represent the molecular type and the last two digits the average percentage by weight of chlorine. Gas-liquid chromatography with highly sensitive and selective detectors has been employed successfully in their detection at low levels. PCB compounds are slightly soluble in water; soluble in fats, oils, and organic solvents, and resistant to both heat and biological degradation. Typically, the specific gravity, boiling point, and melting point of PCB's increase with their chlorine content. PCB's are relatively non-flammable have useful cooling, insulating, and dielectric properties, and principally are used in the electrical industry in capacitors and transformers.

Exposure to PCB is known to cause skin lesions and to increase liver enzyme activity that may have a secondary effect on reproductive processes. It is not clear whether the effects are due to the PCB's or their contaminants, the chlorinated dibenzofurans, that are very harmful, while chlorinated dibenzofurans are a byproduct of PCB production, it is not known whether they are also produced by the degradation of PCB's.

Analyses of 40 fish, in one program, indicated only one fish to contain less than 1 ug/g PCB with the ten highest residues ranging from 19 ug/g to 213 ug/g whole body weight.

Studies of the Milwaukee River revealed ambient water concentrations of 2.0 to 2.8 ug/l and residues in fish as high as 405 ug/g. Open water Lake Michigan concentrations have been reported to be less than 0.01 ug/l with mean residues in coho salmon of about 15 ug/g. The Food and Drug Administration guideline for protecting the health of human consumers of fish is 5 ug/g in tissue residues of fish. Based on Lake Michigan data, which indicate that at a concentration of 0.01 ug/l the fish tissue residues exceed a level found to be non-hazardous to man, a criterion of 0.001 ug/l in freshwater is warranted.

Bluegill sunfish exposed to Aroclors 1248 and 1254, exhibited a bioaccumulation factor of 7.1 x 10^4. The bioaccumulation factor for gizzard shad in the Saginaw River (Michigan) varied between 0.6 x 10^5 and 1.5 x 10^5 for Aroclor 1254. A residue level of 2 ug/g in fish consumed by commercial ranch mink has been shown to prevent survival of offspring. Reproduction was almost totally eliminated in ranch mink fed a beef diet containing 0.64 ug/g of Aroclor 1254. This suggests that a mink-food tissue level of not more than 0.5 ug/g would be required to protect the wildlife consumer.

Median PCB concentrations in whole fish of eight species from Long Island Sound obtained in 1970 were reported to be in the order of 1 ug/g, as were comparable concentrations off the coast of Southern California. Generally, residues in ocean fish have been below 1 ug/g.

Surveys of Escambia Bay (Florida) have produced data on the pathways and effects of PCB's in the estuarine and marine environments. Although the major PCB source, accidental leakage from a PCB manufacturing plant has been terminated, residues continue to be observed in aquatic organisms of the bay. The sediment reservoir of Aroclor 1254 is thought to be a continuing source of PCB to biota. The initial survey of Escambia Bay biota revealed fish, shrimp, and crabs with levels as high as 12 ug/g. Higher levels were detected in higher trophic levels than shrimp, which could implicate a chain transfer from sediment to large animals.

From the Escambia Bay data, which include flow-through bioassays with residue analyses where possible, the following conclusions were reached: (1) all of the Aroclors tested are acutely toxic for certain estuarine organisms; (2) bioassays lasting longer than 96 hours demonstrated that Aroclor 1254 is toxic to commercial shrimp at less than 1 ug/l; (3) fish, particularly sheephead minnows, are extremely sensitive to Aroclor 1254 with 0.1 ug/l being lethal to fry; and (4) acute toxicity of Aroclor 1016 to estuarine organisms is similar to the toxicity of other Aroclors but appears less toxic to fish in long-term exposures than does Aroclor 1254.

Oysters were sensitive to Aroclor 1260 with growth diminished by 44 percent in 10 ug/l and by 52 percent in 100 ug/l. Approximately 10 percent of the pink shrimp died in 100 ug/l, but no apparent effects on pinfish were noted at 100 ug/l. Aroclor 1254 had no apparent effect on juvenile pinfish at 100 ug/l in 48-hour flow-through tests, but killed 100 percent of the pink shrimp. At 100 ug/l of Aroclor 1254 for 96 hours, shell growth of oysters was inhibited and decreased only 41 percent at levels of 10 ug/l. The toxicity of Aroclor 1248 and 1242 to shrimp and pinfish was similar to that of Aroclor 1254. Aroclor 1242 was toxic to oysters at 100 ug/l. Killfish exposed to 25 mg/l of Aroclor 1221 suffered an 85 percent mortality. In 96-hour bioassays, Aroclor 1016 was toxic to an estimated 50 percent of the oysters, brown shrimp, and grass shrimp at 10 ug/l; it was toxic to 18 percent of the pinfish at 100 ug/l.

Young oysters exposed to Aroclor 1254 in flowing sea water for 24 weeks experienced reduction in growth rates at 4.0 ug/l, but apparently were not affected by 1.0 ug/l/ Oysters accumulated as much as 100,000 times the testwater concentration of 1.0 ug/l. Tissue alterations were noted in the oysters exposed to 5.0 ug/l. No significant mortality was observed in oysters exposed continuously to 0.01 ug/l of Aroclor 1254 for 56 weeks.

Blue crabs apparently were not affected by a 20 day exposure to 5.0 ug/l of Aroclor 1254. Pink shrimp exposed under similar conditions experienced a 72 percent mortality. In subsequent flow-through bioassays, 51 percent of the juvenile shrimp were killed by Aroclor 1254 in 15 days and 50 percent of the adult shrimp were killed at 3.0 ug/l in 35 days. From pathological examinations of the exposed pink shrimp, it appears that Aroclor 1254 facilitates or enhances the expression of latent viral infections. Aroclor 1254 was lethal to grass shrimp at 4.0 ug/l in 16 days, to amphipods at 10 ug/l in 30 days, and to juvenile spot at 5.0 ug/l after 20 to 45 days. Sheephead minnows were the most sensitive estuarine organisms to Aroclor 1254 with 0.3 ug/l being lethal to the fy within 2 weeks. Aroclor 1016 in two different 42- day flow-through bioassays caused significant mortalities of pinfish at 32 ug/l and 21 ug/l. Pathological examination of those exposed to 32 ug/l revealed several liver and pancreatic alterations. Sheephead minnows in 28 day Aroclor 1016 flow-through bioassays were not affected by concentrations of 10 ug/l or less, but died at 32 and 100 ug/l. The bioaccumulation factors for the different flow-through bioassays ranged from 2.5 x 10^3 for sheephead minnows to 1.0 x 10^5 for oysters.

Based upon an accumlation factor of 100,000 in the oyster, it may be necessary to limit the marine water concentration of PCB's to a maximum of 0.01 ug/l to protect the human consumer.

Evidence is accumlating that PCB's do not contribute to shell thinning of bird eggs. Dietary PCB's produced no shell thinning in eggs of Mallard ducks. PCB's may increase susceptibility to infectous agents such as viral diseases, and increase the activity of liver enzymes that degrade steroids, including sex hormones. Laboratory studies have indicated that PCB with its derivatives or metabolites, causes enbryonic death of birds.

Chlorine-Free Available, - Total Residual

Elemental chlorine is a greenish-yellow gas that is highly soluble in water. It reacts readily with mandy inorganic substances and all animal and plant tissues.

The denaturing effect of chlorine on animal and plant tissues forms the basis for its use as an effective water or wastewater disinfectant. When chlorine dissolves in water, it hydrolyzes according to the reaction: $Cl_2 + H_2O = HOCl + H^+ + Cl^-$. Unless the concentration of the chlorine solution is above 1,000 mg/l, all chlorine will be in the form of HOCl or its disassociated ions H^+ and OCl^-. The HOCl is a weak acid and disassociates according to the equation $HOCl = H^+ + OCl^-$.

The ratio between HOCl and OCl^- is a function of the pH, with 96 percent HOCl remaining at pH 6, 75 percent at pH 7, 22 percent at pH 8 and 3 percent at pH 9. The relationship of HOCl and pH is significant as the undisassociated form appears to be the bactericidal agent in the use of chlorine for disinfection.

Chlorine is not a natural constituent of water. Free available chlorine (HOCl and OCl) and combined available chlorine (mono- and di-chloramines) appear transiently in surface or ground waters as a result of disinfection of domestic sewage or from industrial processes that use chlorine for bleaching operations or to control organisms that grow in cooling water systems. Chlorine in the free available form reacts readily with nitrogenous organic materials to form chloramines. These compounds are harmful to fish. Chloramines have been shown to be slightly less harmful to fish than free chlorine, but their toxicity is considered to be close enough to free chlorine that differentiation is not warranted. Since the addition of chlorine or hypochlorites to water containing nitrogenous materials rapidly forms chloramines, toxicity in most waters is related to the chloramine concentration. The toxicity to aquatic life of chlorine will depend upon the concentration of total residual chlorine, which is the relative amount of free chlorine plus chloramines. The persistence of chloramines is dependent on the availability of material with a lower oxidation-reduction potential. In most receiving water, chloramines will combine with such materials within a few days to form other compounds that may have toxic effects on fish.

In field studies in Maryland and Virginia it was observed that, downstream from plants discharging chlorinated sewage effluents, the total numbers of fish species were drastically reduced with the stream bottom clear of the wastewater organisms characteristically present in unchlorinated wastewater discharges. No fish were found in water with a chlorine residual above 0.37 mg/l and the species diversity index reaches zero at 0.25 mg/l. A 50 percent reduction in the species diversity index occured at 0.10 mg/l. Of the 45 species of fish observed in the study areas, the brook trout and brown trout were the most sensitive and were not found at residual chlorine levels above about 0.02 mg/l. In studies of caged fish placed in waters downstream from chlorinated wastewater discharge, it has been reported that 50 percent of the rainbow trout died within 96 hours at residual chlorine concentrations of 0.014 to 0.029 mg/l. Some fish died as far as 0.8 miles (1.3 km) downstream from the outfall. Studies indicate that salmonids are the most sensitive fish to chlorine. A residual chlorine concentration of 0.006 mg/l was lethal to trout fry in two days. The 7-day LC50 for rainbow trout was 0.08 mg/l with an estimated median period of survival of one year at 0.004 mg/l. Rainbow trout were shown to avoid a concentration of 0.001 mg/l. It has been demonstrated that brook trout had a mean survival time of 9 hours at 0.35 mg/l 18 hours at 0.08 mg/l and 48 hours at 0.04 mg/l, with mortality of 67 percent after 4 days at 0.01 mg/l. A 50 percent brown trout mortality has been observed at 0.02 mg/l within 10.5 hours and at 0.01 mg/l within 43.5 hours.

The range of acutely lethal residual chlorine concentrations is narrow for various species of warm water fish. 96 - hour LC50 values have been determined for the walleye, black bullhead, white sucker, yellow perch, largemouth bass, and fathead minnow. The observed concentration range was 0.09 to 0.30 mg/l.

Using fathead minnows in a continuous bioassay technique, it has been found that an average concentration of 0.16 to 0.21 mg/l killed all of the test fish and that concentrations as low as 0.07 mg/l caused partial kills. A 50 percent mortality has been demonstrated of smallmouth bass exposed to 0.5 mg/l within fifteen hours. The mean 96-hour LC50 value for golden shiners was 0.19 mg/l. It has been found for fathead minnows and the freshwater crustacean Gammarus pseudolimnaeus in dilute wastewater that the 96-hour LC50 of total residual chlorine for Gammarus was 0.22 mg/l and that all fathead minnows were dead after 72 hours at 0.15 mg/l. At concentrations of 0.9 mg/l, all fish survived for seven days, when the first death occurred. In exposure to 0.05 mg/l residual chlorine, investigators found reduced survival of Gammarus and at 0.0034 mg/l ther was reduced repreduction. Growth and survival of fathead minnows after 21 weeks were not affected by continuous exposure to 0.043 mg/l residual chlorine. The highest level showing no significant effect was 0.016 mg/l. With secondary waste water effluent, reproduction by Gammarus was reduced by residual concentrations above 0.012 mg/l residual chlorine.

In marine water, 0.05 mg/l was the critical chlorine level for young Pacific salmon exposed for 23 days. The lethal threshold for chinhook salmon and coho salmon for a 72-hour exposure was noted to be less than 0.01 mg/l chlorine. Studies on the effect of residual chlorine to marine phytoplankton indicate that exposure to 0.10 mg/l reduced primary production by 70 percent while 0.2 mg/l for 1.5 hours resulted in 25 percent of primary production. Labortory studies on ten species of marine phytoplankton indicate tht a 50 percent reduction in growth rate occurred at chlorine concentrations of 0.075 to 0.250 mg/l during a 24-hour exposure period. Oysters are sensitive to chlorine concentrations of 0.01 to 0.05 mg/l and react by reducing pumping activity. At chlorine concentrations of 1.0 mg/l, effective pumping could not be maintained.

Chromium-Total

Chromium, in its various valence states, is hazardous to man. It can produce lung tumors when inhaled and induces skin sensitizations. Large doses of chromates have corrosive effects on the intestinal tract and can cause inflammation of the kidneys. Levels of chromate ions that have no effect on man appear to be so low as to prohibit determination to date.

The toxicity of chromium salts toward aquatic life varies widely with the species, temperature, pH, valence of the chromium, and synergistic or antagonistic effects, especially that of hardness. Fish are relatively tolerant of chromium salts, but fish food organisms and other lower forms of aquatic life are extremely sensitive. Chromium also inhibits the growth of algae.

In some agricultural crops, chromium can cause reduced growth or death of the crop. Adverse effects of low concentrations of chromium on corn, tobacco and sugar beets have been documented.

Copper-Total

Copper salts occur in natural surface waters only in trace amounts, up to about 0.05 mg/l, so that their presence generally is the result of pollution. This is attributable to the corrosive action of the water on copper and brass tubing, to industrial effluents, and frequently to the use of copper compounds for the control of undesirable plankton organisms.

Copper is not considered to be a cumulative systemic poison for humans, but it can cause symptoms of gastroenteritis, with nausea and intestinal irritations, at relatively low dosages. The limiting factor in domestic water supplies is taste. Threshold concentrations for taste have been generally reported in the range of 1.0-2.0 mg/l of copper, while as much as 5-7.5 mg/l makes the water completely unpalatable.

The toxicity of copper to aquatic organisms varies significantly, not only with the species, but also with the physical and chemical characteristics of the water, including temperature, hardness, turbidity, and carbon dioxide content. In hard water, the toxicity of copper salts is reduced by the precipitation of copper carbonate or other insoluble compounds. The sulfates of copper and zinc, and of copper and cadmium are synergistic in their toxic effect on fish.

Copper concentrations less than 1 mg/l have been reported to be toxic, particularly in soft water, to many kinds of fish, crustaceans, mollusks, insects, phytoplankton and zooplankton. Concentrations of copper, for example, are detrimental to some oysters above 0.1 ppm. Oysters cultured in sea water containing 0.13-0.5 ppm of copper deposited the metal in their bodies and became unfit as a food substance.

Oil and Grease

Oil and grease exhibit an oxygen demand. Oil emulsions may adhere to the gills of fish or coat and destroy algae or other plankton. Deposition of oil in the bottom sediments can serve to exhibit normal benthic growths, thus interrupting the aquatic food chain. Soluble and emulsified material ingested by fish may taint the flavor of the fish flesh. Water soluble components may exert toxic action on fish. Floating oil may reduce the re-aeration of the water surface and in conjunction with emulsified oil may interfere with photosynthesis. Water insoluble components damage the plumage and costs of water animals and fowls. Oil and grease in a water can result in the formation of objectionable surface slicks preventing the full aesthetic enjoyment of the water.

Oil spills can damage the surface of boats and can destroy the aesthetic characteristics of beaches and shorelines.

pH, Acidity and Alkalinity

Acidity and alkalinity are reciprocal terms. Acidity is produced by substances that yield hydrogen ions upon hydrolysis and alkalinity is produced by substances that yield hydroxyl ions. The terms "total acidity" and "total alkalinity" are often used to express the buffering capacity of a solution. Acidity in natural waters is caused by carbon dioxide, mineral acids, weakly dissociated acids, and the salts of strong acids and weak bases. Alkalinity is caused by strong bases and the salts of strong alkalies and weak acids.

The term pH is a logarithmic expression of the concentration of hydrogen ions. At a pH of 7, the hydrogen and hydroxyl ion concentrations are essentially equal and the water is neutral. Lower pH values indicate acidity while higher values indicate alkalinity. The relationship between pH and acidity or alkalinity is not necessarily linear or direct.

Waters with a pH below 6.0 are corrosive to water works structures, distribution lines, and household plumbing fixtures and can thus add such constituents to drinking water as iron, copper, zinc, cadmium and lead. The hydrogen ion concentration can affect the "taste" of the water. At a low pH water tastes "sour". The bactericidal effect of chlorine is weakened as the pH increases, and it is advantageous to keep the pH close to 7. This is very significant for providing safe drinking water.

Extremes of pH or rapid pH changes can exert stress conditions or kill aquatic life outright. Dead fish, associated algal blooms, and foul stenches are aesthetic liabilities of any waterway. Even moderate changes from "acceptable" criteria limits of pH are deleterious to some species. The relative toxicity to aquatic life of many materials is increased by changes in the water pH. Metalocyanide complexes can increase a thousand-fold in toxicity with a drop of 1.5 pH units. The availability of many nutrient substances varies with the alkalinity and acidity. Ammonia is more lethal with a higher pH.

The lacrimal fluid of the human eye has a pH of approximately 7.0 and a deviation of 0.1 pH unit from the norm may result in eye irritation for the swimmer. Appreciable irritation will cause severe pain.

Phosphorus-Total

During the past 30 years, a formidable case has developed for the belief that increasing standing crops of aquatic plant growths, which often interfere with water uses and are nuisances to man, frequently are caused by increasing supplies of phosphorus. Such phenomena are associated with a condition of accelerated eutrophication or aging of waters. It is generally recognized that phosphorus is not the sole cause of eutrophication, but there is evidence to substantiate that it is frequently the key element in all of the elements required by fresh water plants and is generally present in the least amount relative to need. Therefore, an increase in phosphorus allows use of other, already present, nutrients for plant growths. Phosphorus is usually described, for this reasons, as a "limiting factor."

When a plant population is stimulated in production and attains a nuisance status, a large number of associated liabilities are immediately apparent. Dense populations of pond weeds make swimming dangerous. Boating and water skiing and sometimes fishing may be eliminated because of the mass of vegetation that serves as an physical impediment to such activities. Plant populations have been associated with stunted fish populations and with poor fishing. Plant nuisances emit vile stenches, impart tastes and odors to water supplies, reduce the efficiency of industrial and municipal water treatment, impair aesthetic beauty, reduce or restrict resort trade, lower waterfront property values, cause skin rashes to man during water contact, and serve as a desired substrate and breeding ground for flies.

Phosphorus in the elemental form is particularly toxic, and subject to bioaccumulation in much the same way as mercury. Colloidal elemental phosphorus will poison marine fish (causing skin tissue breakdown and discoloration). Also, phosphorus is capable of being concentrated and will accumulate in organs and soft tissues. Experiments have shown that marine fish will concentrate phosphorus from water containing as little as 1 ug/l.

Total Suspended Solids

Suspended solids include both organic and inorganic materials. The inorganic components include sand, silt, and clay. The organic fraction includes such materials as grease, oil, tar, animal and vegetable fats, various fibers, sawdust, hair, and various materials from sewers. These solids may settle out rapidly and bottom deposits are often a mixture of both organic and inorganic solids. They adversely affect fisheries by covering the bottom of the stream or lake with a blanket of material that destroys the fish-food bottom fauna or the spawning ground of fish. Deposits containing organic materials may deplete bottom oxygen supplies and produce hydrogen sulfide, carbon dioxide, methane, and other noxious gases.

In raw water sources for domestic use, state and regional agencies generally specify that suspended solids in streams shall not be present in sufficient concentration to be objectionable or to interfere with normal treatment processes. Suspended solids in water may interfere with many industrial processes, and cause foaming in boilers, or encrustations on equipment exposed to water, especially as the temperature rises. Suspended solids are undesirable in water for textile industries; paper and pulp; beverages; dairy products; laundries; dyeing; photography; cooling systems, and power plants. Suspended particles also serve as a transport mechanism for pesticides and other substances which are readily sorbed into or onto clay particles.

Solids may be suspended in water for a time, and then settle to the bed of the stream or lake. These settleable solids discharged with man's wastes may be inert, slowly biodegradable materials, or rapidly decomposable substances. While in suspension, they increase the turbidity of the water, reduce light penetration and impair the photosynthetic activity of aquatic plants.

Solids in suspension are aesthetically displeasing. When they settle to form sludge deposits on the stream or lake bed, they are often much more damaging to the life in water, and they retain the capacity to displease the senses. Solids, when transformed to sludge deposits, may do a variety of damaging things, including blanketing the stream or lake bed and thereby destroying the living spaces for those benthic organisms that would otherwise occupy the habitat. When of an organic and therefore decomposable nature, solids use a portion or all of the dissolved oxygen available in the area. Organic materials also serve as a seemingly inexhaustible food source for sludgeworms and associated organisms.

Turbidity is principally a measure of the light absorbing properties of suspended solids. It is frequently used as a substitute method of quickly estimating the total suspended solids when the concentration is relatively low.

Zinc-Total

Occurring abundantly in rocks and ores, zinc is readily refined into a stable pure metal and is used extensively for galvanizing, in alloys, for electrical purposes, in printing plates, for dye-manufacture and for dyeing processes, and for many other industrial purposes. Zinc salts are used in paint pigments, cosmetics, pharmaceuticals, dyes, insecticides, and other products too numerous to list herein. Many of these salts (e.g., zinc chloride and zinc sulfate) are highly soluble in water; hence it is to be expected that zinc might occur in many industrial wastes. On the other hand, some zinc salts (zinc carbonate, zinc oxide, zinc sulfide) are insoluble in water and consequently it is to be expected that some zinc will precipitate and be removed readily in most natural waters.

In zinc-mining areas, zinc has been found in waters in concentrations as high as 50 mg/1 and in effluents from metal-plating works and small-arms ammunition plants it may occur in significant concentrations. In most surface and ground waters, it is present only in trace amounts. There is some evidence that zinc ions are adsorbed strongly and permanently on silt, resulting in inactivation of the zinc.

Concentrations of zinc in excess of 5 mg/1 in raw water used for drinking water supplies cause an undesirable taste which persists through conventional treatment. Zinc can have an adverse effect on man and animals at high concentrations.

In soft water, concentrations of zinc ranging from 0.1 to 1.0 mg/1 have been reported to be lethal to fish. Zinc is thought to exert its toxic action by forming insoluble compounds with the mucous that covers the gills, by damage to the gill epithelium, or possibly by acting as an internal poison. The sensitivity of fish to zinc varies with species, age and condition, as well as with the physical and chemical characteristics of the water. Some acclimatization to the presence of zinc is possible. It has also been observed that the effects of zinc poisoning may not become apparent immediately, so that fish removed from zinc-contaminated to zinc-free water (after 4-6 hours of exposure to zinc) may die 48 hours later. The presence of copper in water may increase the toxicity of zinc to aquatic organisms, but the presence of calcium or hardness may decrease the relative toxicity.

Observed values for the distribution of zinc in ocean waters vary widely. The major concern with zinc compounds in marine waters is not one of acute toxicity, but rather of the long-term sub-lethal effects of the metallic compounds and complexes. From an acute toxicity point of view, invertebrate marine animals seem to be the most sensitive organisms tested. The growth of the sea urchin, for example, has been retarded by as little as 30 ug/l of zinc.

Zinc sulfate has also been found to be lethal to many plants, and it could impair agricultural uses.

PART A

CHEMICAL WASTES

SECTION VII

CONTROL AND TREATMENT TECHNOLOGY

General Methodology

Curry[371] presents a general methodology for metallic waste treatment. Some of the principles are also applicable, however, to other types of wastes. The following outline conveys, with some modifications, the general principles of Curry's work:

- I. Omit flows with a pollutant concentration lower than the concentration in equilibrium with the precipitate formed
- II. Reduce the waste water volumes requiring treatment
- III. Minimize the solubility cf the pollutant
  - A. Eliminate compounds that form soluble complexes
  - B. Reduce concentration of interfering ions that increase pollutants solubilities
  - C. Maintain conditions that minimize total solubility
- IV. Control conditions to increase the proportion of the pollutants in the ionic form required for its precipitation or adsorbent reaction
- V. Avoid conditions that will form harmful amounts of gases during treatment
- VI. Select a process that will give the lowest practicable or economically achievable amounts of pollutants in the effluent, up to and including no discharge of pollutants
- VII. Select a process that produces a sludge that can be disposed of in accordance with environmental considerations.

Pollutant-Specific Treatment Technology

Applicable control and treatment technology relevant to specific pollutants is discussed in the J.W. Patterson, et al, report "Wastewater Treatment Technology".[208] Based on the data of that report and other sources, the following information is given on pollutant-specific treatment technology.

Aluminum

Precipitates as the hydroxide at pH 5.5-7.[371], [462] The minimum solubility is at pH 6.0. Some halides may increase the solubility of aluminum by complexation reactions and thus change the conditions.[462]

Ammonia

Ammonia can be removed from waste waters by stripping with steam or air. Steam stripping systems are capable of achieving effluent ammonia concentrations of from 5 to 30 mg/l. Cooling towers could be considered as air strippers of ammonia from contaminated waters. However, the reverse effect can occur, i.e. air-borne ammonia is absorbed.[375]

Antimony

Solubility data indicates a potential removal of about 90 percent by lime coagulation treatment.[18]

Arsenic

Treatment processes employed involve coagulation at pH 6.0 to produce ferric hydroxide floc to tie up the arsenic and carry it from solution. This process has consistently yielded arsenic levels of 0.05 mg/l or less.

Barium

Precipitation as barium sulfate after addition of ferric or sodium sulfate at pH 6.0 yields effluent levels of 0.03-0.27 mg/l.

Beryllium

No information was found concerning treatment methods for the removal of beryllium from industrial waste waters. However, precipitation of insoluble sulfate, carbonate or hydroxide may be possible.

Boron

No practicable treatment is reported. Borate-nitrate corrosion inhibition treatment is used in closed-loop house service water systems. Boron from this source could be reduced by minimizing the use of boron-containing chemicals. However, some boron chemicals could discharge from ash sluicing operations as a result of boron content in raw coal used for firing.

Cadmium

Cadmium precipitates as the hydroxide at elevated pH. Its solubility at pH 10 is 0.1 mg/l. The presence of iron hydroxide can enhance removal due to co-precipitation with, or adsorption on the iron floc. Complexing agents in the waste stream can reduce the effectiveness of precipitative removal.

Calcium

The lime-soda process precipitates calcium as calcium carbonate.

Chlorine Residuals

An end-of-pipe treatment for reducing chlorine levels is the addition of reducing agents such as sodium bisulfite ($NaHSO_3$). Chlorine being an oxidizing agent will oxidize these chemicals. Dechlorination with sulfur dioxide has been practiced for many years in water treatment [30] and, more recently, on wastewater.[31] Sulfur dioxide is favored for its low cost and ease of handling. It is fed by equipment identical to that used in chlorination systems. The reaction in dechlorination is instantenous, the resulting products being chloride and sulfate ions. The theoretical requirements is 0.9 mg/l of sulfur dioxide per mg/l of residual chlorine (not chlorine dosage). Actual practice indicates the requirement to be nearer 1:1. It is equally effective for combined or free residual.[18] One mole of bisulfite is required per mole of chlorine or 1.47 mg/l per mg/l of chlorine. By maintaining a 10% excess of sodium bisulfite in the discharge stream, chlorine can be eliminated. However, the excess sodium sulfite creates an oxygen demand, thus substituting one pollutant problem for another.

Chromium

The most common method of chromium removal is chemical reduction of hexavalent chromium to the trivalent ion and subsequent chemical precipitation. The standard reduction technique is to lower the waste stream pH to 3 or below by addition of sulfuric acid, and to add sulfur dioxide, sodium bisulfite (or metabisulfite or hydrosulfite), or ferrous sulfate as reducing agent. Trivalent chromium is then removed by precipitation with lime at pH 8.5-9.5.

The residual of hexavalent chromium after the reduction step depends on the pH, retention time, and the concentration and type of reducing agent employed. The following effluent levels are reported for treatment of industrial wastes:

metal finishing wastes,
  using sulfure dioxide - - - - - - - - - 1 mg/l
metal finishing wastes,
  using sulfur dioxide - - - - - - - - - "zero"
wood preserving wastes,
  using sulfur dioxide - - - - - - - - - 0.1 mg/l
electroplating wastes,
  using sodium bisulfite - - - - - - - - 0.7-1.0 mg/l
cooling tower blowdown,
  using metabisulfite - - - - - - below 0.5 mg/l
cooling tower blowdown,
  using metabisulfite - - - - - - - - - - 0.025-0.05 mg/l
metal plating wastes,
  using metabisulfite - - - - - - - - - - 0.1 mg/l or less
chrome plating wastes,
  using metabisulfite - - - - - - - - - - 0.05-0.1 mg/l

Ion exchange treatment of metal finishing wastes has successfully met chrome effluent standards equivalent to a hexavalent chromium concentration of 0.023 mg/l.

The solubility of trivalent chromium is less than approximately 0.1 mg/l in the pH range 8-9.5. Effluent levels, after precipitation of industrial wastes with lime, are reported as follows:

electroplating wastes,
  using coagulant aid - - - - - - - - - - - - - - 0.06 mg/l
metal finishing wastes,
  using settling - - - - - - - - - - - - - - - below 3 mg/l
wood preserving wastes,
  using settling - - - - - - - - - - - - - - - - - 0.02 mg/l
metal finishing wastes,
  using an anionic polyelectrolyte - - - - - - - 0.75 mg/l

Ion exchange removal can effect complete removal of trivalent chromium.

The U.S. Atomic Energy Commission reports total chromate effluents of 0.1-0.2 mg/l after either chemical treatment or ion exchange.[372-373]

Cobalt

No information was found concerning treatment methods for the removal of cobalt from industrial waste waters.

Copper

Effluent concentrations of 0.5 mg/l can be consistently achieved by precipitation with lime employing proper pH control and proper settler design and operation. The maximum solubility of the metal hydroxide is in the range pH 8.5-9.5. In a powerplant, copper can appear in the waste water effluent as a result of corrosion of copper-containing components of the necessary plant hydraulic systems. Normally, every practicable effort is made, as a part of standard design and operating practices, to reduce corrosion of plant components. However, copper is not used in once-through boilers and, consequently, is not found in corresponding spent cleaning solutions. Excessively stringent effluent limitations on copper may necessitate complete redesign and alteration of condenser cooling and other systems. The following effluent levels of copper are reported for full-scale treatment of industrial wastes by lime precipitation followed by sedimentation (except as noted):

metal processing wastes - - - - - - - - - 0.5 mg/l
metal processing wastes - - - - - - - - - 0.2-2.5 mg/l
metal processing wastes, using sand filtration - - - - - - - - - - - - 0.2-0.5 mg/l
metal fabrication wastes, using coagulant - - - - - - - - - - - - 2.2 mg/l
metal finishing wastes - - - - - - - avg. 0.2 mg/l
metal mill wastes - - - - - - - - - - - - 1-2 mg/l
wood preserving wastes - - - - - - - - - 0.1-0.4 mg/l

A significant problem in achieving a low residual concentration of copper can result if complexing agents are present, especially cyanide and ammonia.

Iron

In general, acidic and/or anaerobic conditions are necessary for appreciable concentrations of soluble iron to exist. "Complete" iron removal with lime addition, aeration, and settling followed by sand filtration has been reported. Existing technology is capable of soluble iron removals to levels well below 0.3 mg/l. Failure to achieve these levels would be the result of improper pH control. The minimum solubility of ferric hydroxide is at pH 7. In some cases, apparently soluble iron may actually be present as finely divided solids due to inefficient settling of ferric hydroxide. Polishing treatment such as rapid sand filters will remove these solids. In a powerplant, iron, as with copper, can appear in the waste water effluent as a result of corrosion to iron-containing components of the necessary plant hydraulic systems. Normally, every practicable effort is made, as a part of standard design and operating procedures, to reduce corrosion of plant components. Excessively stringent effluent limitations on iron, as with copper, may necessitate complete redesign and alteration of condenser cooling and other systems.

Lead

Precipitation by lime and sedimentation has been reported. Little data is available on effluent lead after treatment; however, the extreme insolubility of lead hydroxide indicates that good conversion of soluble lead to insoluble lead can be achieved, with subsequent removal by settling or filtration.

Magnesium

The lime-soda process precipitates magnesium as the hydroxide.

Manganese

Precipitates upon lime addition. Significant removals during water treatment are achieved at pH 9.4 and above.

Molybdenum

No information was found concerning treatment methods for the removal of molybdenum from industrial waste waters. However, precipitation as chloride or sulfide may be possible.

Mercury

General treatment methods exist which are applicable to mercury-bearing waste streams. One of the most common, simplest, and most effective methods to remove mercury from solution is precipitation of an insoluble mercury compound. Sodium sulfide (Na_2S) and sodium hydro-sulfide (NaHS) are effective in forming the extremely insoluble HgS. This method is not favored, however, when recovery of mercury is desired, since offensive and poisonous hydrogen sulfide (H_2S) gas is formed in the reduction process. By keeping the pH about 10 the H_2S problem can be avoided while enhancing the production of sulfide ion for precipitation.[462] Other methods include filtration with adsorptive compounds such as activated carbon, graphite powder and powdered zinc, chemical flocculation, and ion exchange.

Nickel

Nickel forms insoluble nickel hydroxide upon addition of lime. Little efficiency is gained above a pH of 10, where the minimum theoretical solubility is 0.01 mg/l. Removal by adsorption on an iron or manganese hydroxide floc is possible.[462]

Oil and Grease

Flotation is efficient in removing emulsified oil and requires minimum space. It can be used without chemical addition, but demulsifiers and coagulants can improve performance in some cases. Whenever possible, primary separation facilities should be employed to remove free oil and solids before the water enters the flotation unit. Multi-stage units are more effective than single-stage units. Partial-recycle units are more effective than full-pressure units. Oil removal facilities including single-cell flotation can achieve effluent oil and grease levels from 10-20 mg/l, while multi-stage units can achieve 2-10 mg/l. Reference 398 gives data on oil and grease levels attained by a number of petroleum refineries using primary gravity separation, flotation (with and without chemicals), chemical flotation, and filtration. Reference 399 presents data on oil and grease levels achieved by dissolved air flotation. Levels ranging from 2-20 mg/l were indicated.

Total Phosphorus(as P)

Phosphorus concentrations of less than 0.1 mg/l can be routinely obtained using two-stage lime clarification at pH 11, followed by multi-media pressure filters. Single-stage lime clarification at pH 9-11 with or without filtration can achieve phosphorus concentrations of 2 mg/l or less. Figure A-VII-1 shows the effect of pH on phosphorus concentration of effluent after filtration. The average concentration for a clarifier pH of 9.5, and prior to filtration was 0.75 mg/l.[374] Precipitation using ferric or aluminum salts has been used.[462]

Potassium

No information was found concerning treatment methods for the removal of potassium from industrial waste waters.

Polychlorinated Biphenyls (PCBs)

PCBs are commonly used as coolants in large transformers. Special care should be taken to prevent leaks and spills and to contain possible spills of these fluids in order to prevent their discharge to water bodies.

Selenium

Under conditions of moderate reduction, selenium may be removed from solution by reduction to the insoluble elemental form.[462]

Silver

Precipitation with chloride ion can remove silver to the mg/l level. However, co-precipitation with other metal hydroxides under alkaline conditions improves silver removal to less than 0.1 mg/l.

Sodium

No information was found concerning treatment methods for the removal of sodium from industrial waste waters.

Sulfate

Use of lime (calcium carbonate) in place of dolomite (mixture of calcium carbonate and magnesium carbonate) in lime treatment will minimize the presence of soluble sulfates, due to insolubility of calcium sulfate and solubility of magnesium sulfate.

Thallium

No information was found concerning treatment methods for the removal of thallium from industrial waste waters.

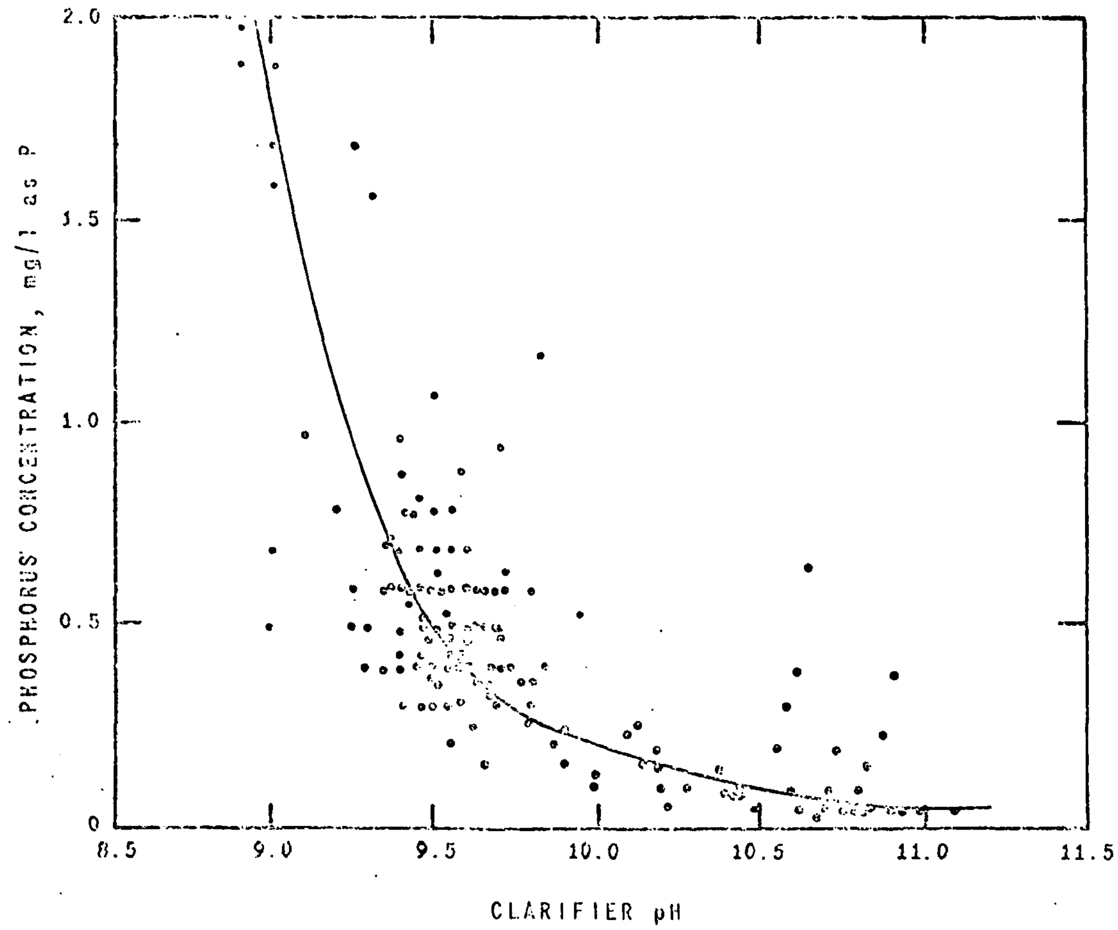


Figure A-VII-1

Effect of pH on Phosphorus Concentration of Effluent from Filters Following Lime Clarifier[374]

However, the trivalent hydroxide is insoluble and may be removed by lime addition.

Tin

No information was found concerning treatment methods for the removal of tin from industrial waste waters. However, precipitation as hydroxide or sulfite may occur.

Titanium

No information was found concerning treatment methods for the removal of titanium from industrial waste water.

Total Dissolved Solids

Removal of total dissolved solids (TDS) from waste waters is one of the more difficult and more expensive waste treatment procedures. Where TDS result from heavy metal or hardness ions, reduction can be achieved by chemical precipitation methods; however, where dissolved solids are present as sodium, calcium, or potassium compounds, then TDS reduction requires more specialized treatment, such as reverse osmosis, electrodialysis, distillation, and ion exchange.

Total Suspended Solids

Suspended solids removal can be achieved by sedimentation and filtration operations employing, in some cases, flocculation-coagulation technology to improve the clarity of the effluent or to speed up the process.

Vanadium

No information was found concerning treatment methods for the removal of vanadium from industrial waste waters. However, precipitation as the insoluble hydroxides may occur. However, vanadium recovery operations discussed elsewhere in this section may include technology for preventing vanadium from dissolving, thus increasing the amount in the reclaimable solid.

Zinc

Lime addition for pH adjustment can result in precipitation of zinc hydroxide. Operational data indicate that levels below 1 mg/l zinc are readily obtainable with lime precipitation. The use of zinc can be minimized since other treatment chemicals are available to reduce corrosion in closed cooling-water cycle. Zinc removals have been reported for a range of industrial systems and, generally, treatment is not for zinc alone. Lime addition with hydroxide precipitation followed by sedimentation (except as indicated) has yielded the following effluent zinc levels:

plating wastes	0.2-0.5 mg/l
plating wastes	2 mg/l
plating wastes, using sand filtration	0.6 mg/l
plating wastes	less than 1 mg/l
fiber manufacturing wastes	less than 1 mg/l
tableware manufacturing wastes, using sand filtration	0.02-0.23 mg/l
fiber manufacturing wastes	0.9-1.5 mg/l
fiber manufacturing wastes	1 mg/l
metal fabrication wastes	0.5-1.2 mg/l
metal fabrication wastes, using sand filtration	0.1-0.5 mg/l

Combined Chemical Treatment

Precipitation

The effluent levels of metal ions attainable by combined chemical treatment depend upon the insolubility of metal hydroxides in the treated water and upon the ability to mechanically separate the hydroxides from the process stream. Reference 379 presents data on the solubilities and other aspects of chemical treatment for the removal of metal ions from waste waters. The theoretical solubilities of copper, nickel, chromium, zinc, silver, lead, cadmium, tellurium and ferric and ferrous iron as a function of pH are shown in Figures A-VII-2, 3. At a pH of 9.5 the solubility of copper, zinc, chromium, nickel and iron is of the order of 0.1 mg/l, or less. Experimental values plotted in Figures A-VII-4, 5 vary somewhat from the theoretical values. Nevertheless, the need for fairly close pH control in order to avoid high concentrations of dissolved metal in the effluent is evident. A pH of 8.5 to 9.0 is best for minimizing the solubility of copper, chromium and zinc, but a pH of 10.0 is optimum for minimizing the solubility of nickel and iron. To limit the solubility of all of these metals in a mixed solution, an intermediate pH level would be selected.

A further aspect related to solubility is the time for reaction. Figure A-VII-6 shows the change in solubilities of zinc, cadmium, copper and nickel with time for various levels of pH.

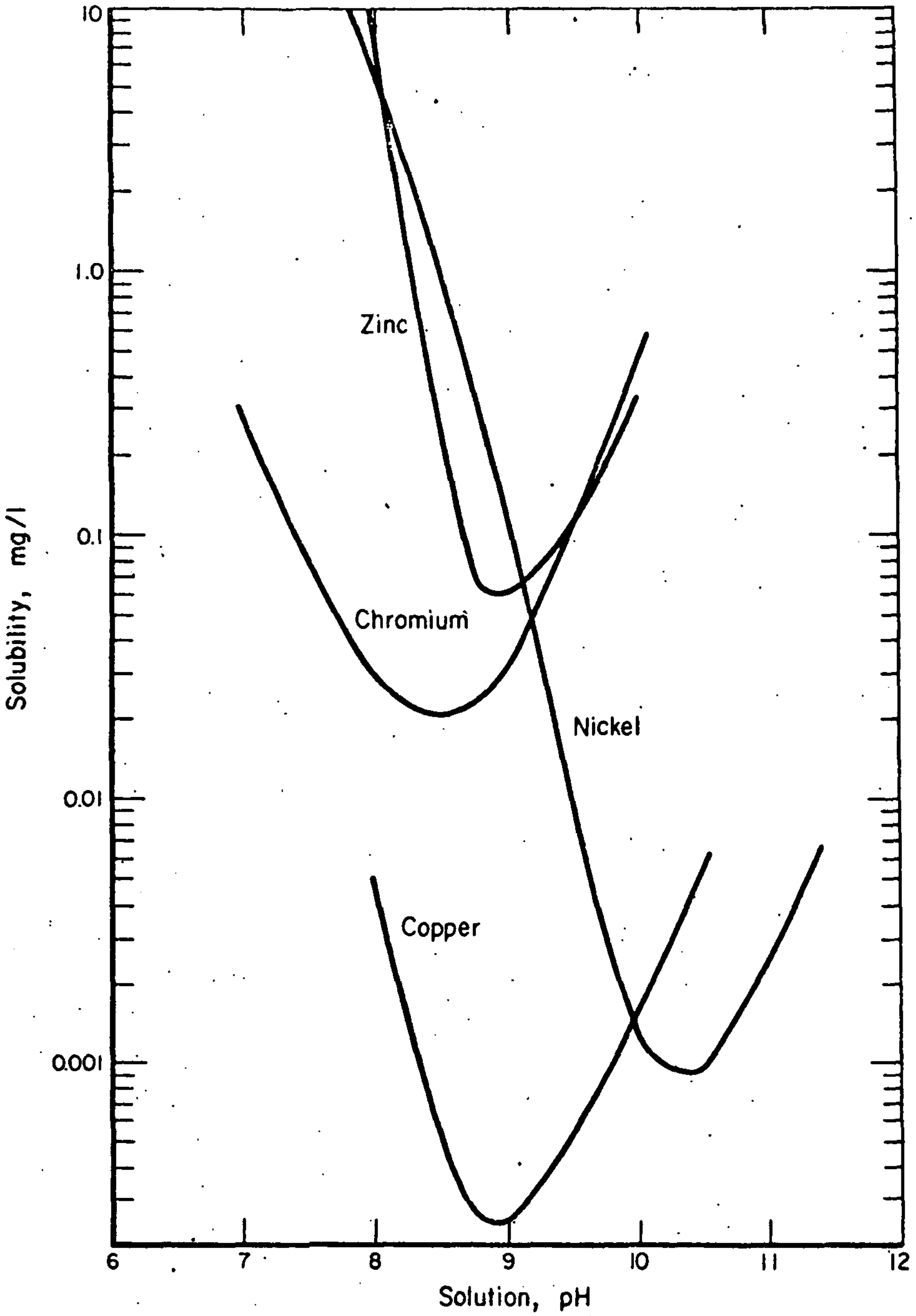


Figure A-VII-2

SOLUBILITY OF COPPER, NICKEL, CHROMIUM, AND ZINC AS A FUNCTION OF pH 379

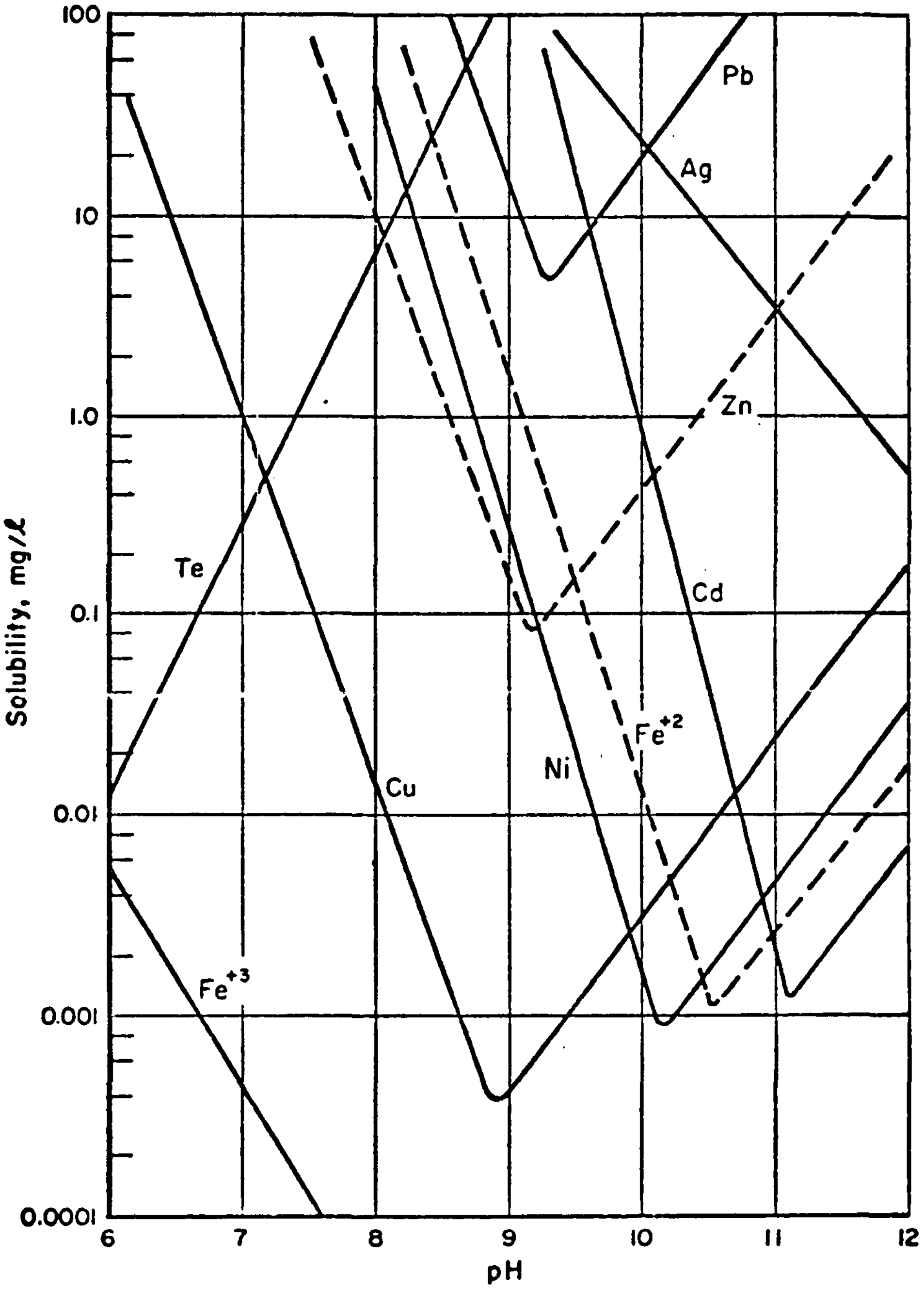


Figure A-VII-3 THEORETICAL SOLUBILITIES OF METAL IONS AS A FUNCTION OF pH 236

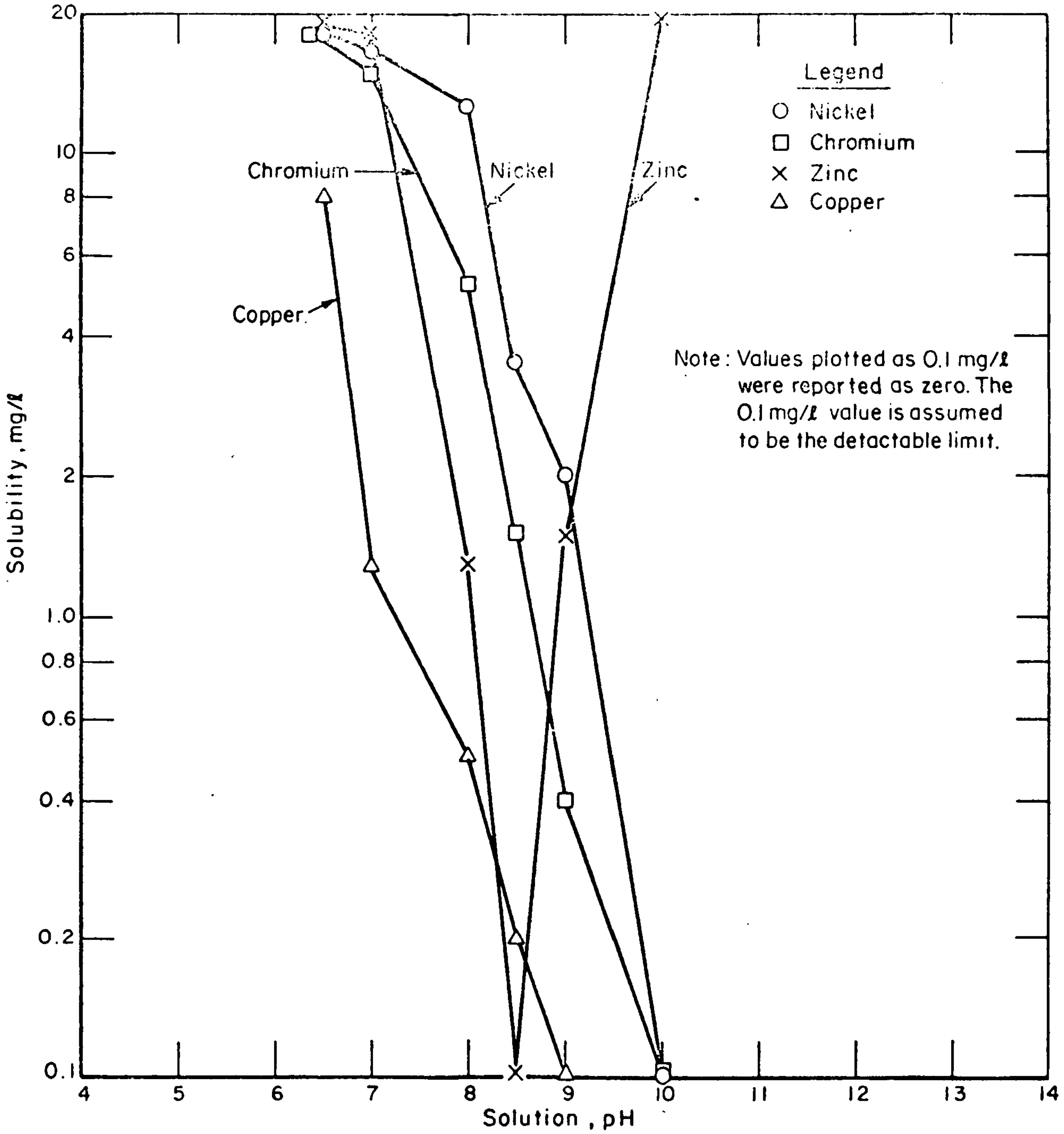


Figure A-VII-4

EXPERIMENTAL VALUES - SOLUBILITY OF METAL IONS AS A FUNCTION OF pH 379

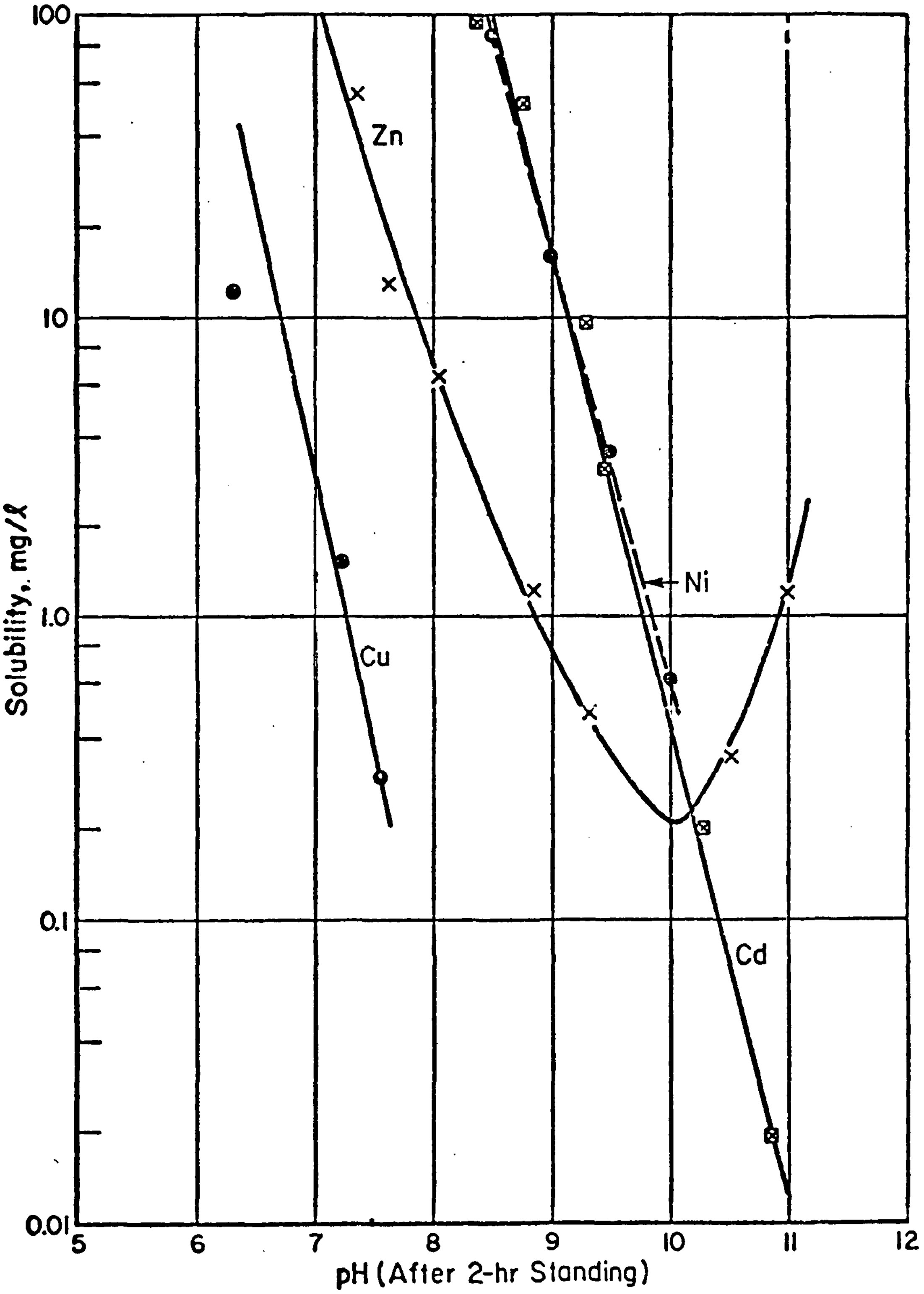
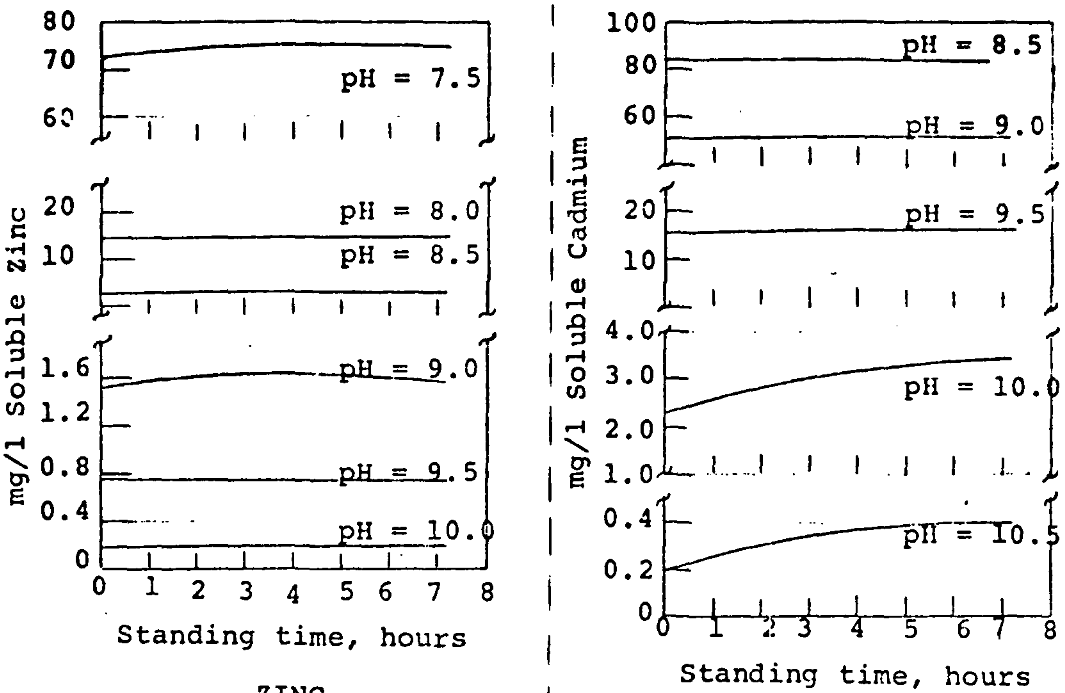


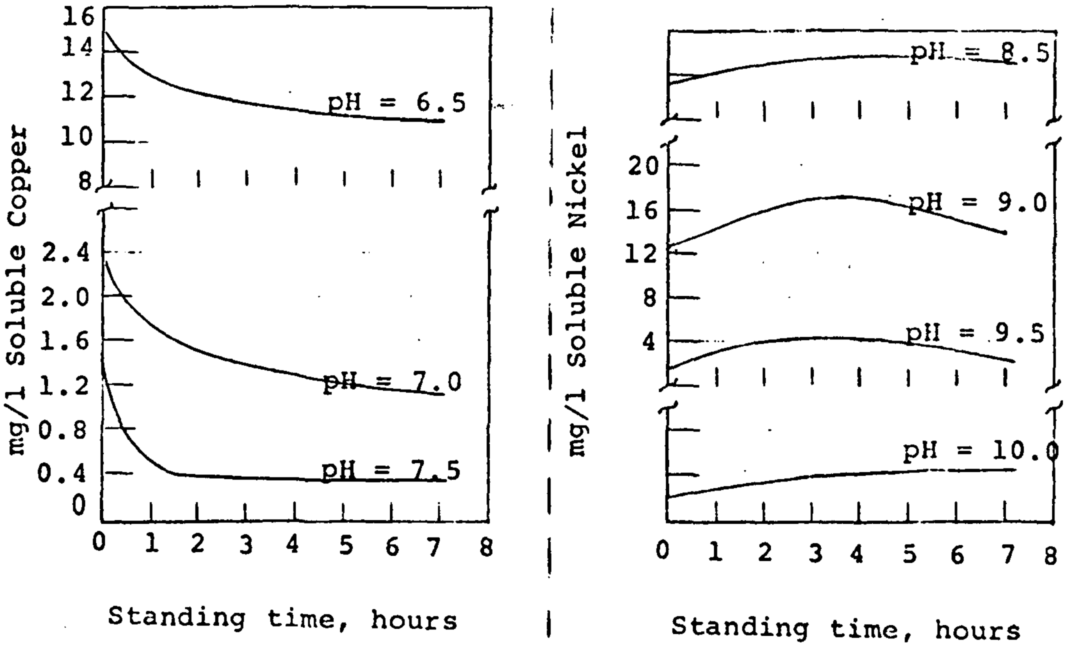
Figure A-VII-5 EXPERIMENTALLY DETERMINED SOLUBILITIES OF METAL IONS AS A FUNCTION OF pH

Reference No. 236



ZINC

CADMIUM



COPPER

NICKEL

Values for pH = 8.0 are 0.2 mg/1

Figure A-VII-6 CHANGE IN THE SOLUBILITIES OF ZINC, CADMIUM, COPPER, AND AND NICKEL PRECIPITATES (PRODUCED WITH LIME ADDITIONS) AS A FUNCTION OF STANDING TIME AND pH VALUE. Reference No. 236.

The theoretical and experimental results do not always agree well with results obtained in practice. Concentrations can be obtained that are lower than the above experimental values, often at pH values that are not optimum on the basis of the above considerations. Effects of co-precipitation and adsorption on the flocculating agents added to aid in settling the precipitate play a significant role in reducing the concentration of the metal ions. Dissolved solids made up of noncommon ions can increase the solubility of the metal hydroxides according to the Debye-Huckel Theory. In a treated solution from a typical electroplating plant, which contained 230 mg/l of sodium sulfate and 1,060 mg/l of sodium chloride, the concentration of nickel was 1.63 times its theoretical solubility in pure water. Therefore, salt concentrations up to approximately 1,000 ppm should not increase the solubility more than 100 percent as compared to the solubility in pure water. However, dissolved solids concentrations of several thousand ppm could have a marked effect upon the solubility of the hydroxide.

When solubilizing complexing agents are present, the equilibrium constant of the complexing reaction has to be taken into account in determining theoretical solubility with the result that the solubility of the metal is generally increased. Complexing agents such as EDTA (ethylene-diamine-tetraacetic acid), could have serious consequences upon the removal of metal ions by precipitation.

Superposed on the situation presented above for chemical treatment for the removal of iron, copper, chromium and nickel could be requirements for removal of other heavy metals and phosphorus. Phosphorus effluents of 2 mg/l are achievable with or without filtration at pH 9-11, therefore, no problem of phosphorus removal is anticipated at pH values which are optimum for the removal of iron, copper, chromium and nickel. Reference 380 presents minimum pH values for complete (effluent generally 1 mg/l) precipitation of metal ions as hydroxides as follows: Sn^{+2}(pH 4.2), Fe^{+3}(pH 4.3), Al^{+3}(pH 5.2), Pb^{+2}(pH 6.3), Cu^{+2}(pH 7.2), Zn^{+2}(pH 8.4), Ni^{+2}(pH 9.3), Fe^{+2}(9.5), Cd^{+2}(pH 9.7), Mn^{+2}(pH 10.6). In the case of amphoteric metals such as aluminum and zinc, resolubilization will occur if the solution becomes too alkaline.

Alkali Selection

Several alkaline materials are available for use in chemical treatment, e.g. lime, hydrated lime, limestone, caustic soda, soda ash. The choice among these may depend on availability, cost, desired effluent quality, ease of handling, reactivity, or characteristics of sludge produced. A comparison of these materials is given in Table A-VII-1. When cost and effluent quality are the most important factors, lime, hydrated lime and limestone would be the more commonly used alkalis.

Lime is readily available and relatively simple to use. In acid (coal) mine drainage applications, it consistently neutralizes the acidity and removes the iron and other metals present in mine drainage at a reasonable cost, if not the least cost. For these reasons, lime is used in most of the estimated 300 plants that treat mine drainage.[380] The relative disadvantages of lime are: an increase in the hardness of the treated water, problems of scale (gypsum) formation on plant equipment, and the difficulties in dewatering or disposal of the sludge volumes produced. There are four basic steps in lime treatment. First, waste waters are neutralized by addition of slurried lime with vigorous mixing for 1-2 minutes. Aeration is provided for 15-30 minutes to oxidize ferrous iron to the ferric state. Solids separation is provided in either mechanical clarifiers, or large earthen settling basins. The treated water is discharged and the sludge is disposed of. Capital costs range from about $40/cu m processed/day for a 40,000 cu m/day process to about $100/cu m/day for a 2,000 cu m/day process to about $1,000/cu m/day for a 400 cu m/day process for treatment of acid mine drainage. Operating costs vary from 3 to 12 cents per 1,000 cu m (11 to 45 cents per million gallons) per mg/l of acidity but are generally in the range 4 to 7 cents/1,000 cu m/mg/l (15 to 27 cents/million gallons/mg/l).[380] Sludge disposal costs can be as much as 50 percent of the total operating costs.

Limestone has several advantages over other alkaline agents. The sludge produced settles more rapidly and occupies a smaller volume. The pH of the treatment is not so sensitive to feed rate. Limestone is easier to handle than the other alkaline materials. Disadvantages center around its slow reactivity which requires larger detention times and larger treatment vessels. As a result of its disadvantages few actual operating systems have been installed.

Aeration

The oxidation of ferrous iron to ferric iron can be accomplished by either diffused or mechanical aeration equipment. Capital costs range from about $2,000 for a 100 cu m flow/day process to about $50,000 for a 10,000 cu m

Table A-VII-1

COMPARISON OF ALKALINE AGENTS FOR CHEMICAL TREATMENT[380]

Agent	Cost, \$/ unit of $CaCO_3$ equiv.
Limestone, Rock (calcium carbonate)	8.82
Limestone, Dust (calcium carbonate)	11.02
Quick Lime (calcium oxide)	14.19
Hydrated Lime (calcium hydroxide)	20.40
Magnesite (magnesium carbonate)	23.24
Soda Ash (sodium carbonate, 50%)	42.08
Dolomite (calcium-magnesium carbonate)	47.70
Ammonium Hydroxide	50.14
Caustic Soda (sodium hydroxide,50%)	67.02

flow/day process. Operating costs will vary from 10-20 percent of the total plant operating costs.[380]

Solids Separation

The first step in separating the precipitated metals is settling, which is very slow for gellike zinc hydroxide, but accelerated by co-precipitation with the hydroxides of copper and chromium. Coagulation can also be aided by adding metal ions such as ferric iron which forms ferric hydroxide and absorbs some of the other hydroxide, forming a floc that will settle. Ferric iron has been used for this purpose in sewage treatment for many years as has aluminum sulfate. Ferric chloride is frequently added to the clarifier of chemical waste-treatment plants in plating installations. Flocculation and settling are further improved by use of polyelectrolytes, which are high molecular weight polymers containing several ionizable ions. Due to their ionic character they are capable of swelling in water and adsorbing the metal hydroxide which they carry down during settling.

Settling is accomplished in the batch process in mechanical clarifier or a stagnant tank, and after a time the sludge may be emptied through the bottom and the clear effluent drawn off through the side or top. The continuous system uses a baffled tank such that the stream flows first to the bottom but rises with a decreasing vertical velocity until the floc can settle in a practically stagnant fluid.

Although the design of the clarifiers has been improved through many years of experience, no settling technique or clarifier is 100 percent effective; some of the floc is found in the effluent - typically 10 to 20 mg/l. This floc could contain 2 to 10 mg/l of metal. Polishing filters or sand filters can be used on the effluent following clarification. The general effectiveness of such filtering has not been ascertained.

Evaporation and Other Processes

Basic processes, in addition to evaporation ponds, include multi-stage flash evaporation, multi-effect long-tube (vertical) evaporation, and vapor compression evaporation. The multi-stage flash evaporation process has been considered potentially applicable to the production of potable water from acid mine drainage.[380] Major problems which have confronted this process are calcium sulfite scaling and brine deposit. The product water at 50 mg/l TDS is suitable for recycle to almost all water uses in steam electric powerplants.

Vapor-compression evaporation systems are being offered on a guaranteed performance basis by a company specialized in their applications. These systems can be used to recover and recycle most of the water contained in the typical blowdown from recirculating process streams. A schematic flow diagram of a typical vapor-compression evaporation system is shown in Figure A-VII-7. The system works as follows:

The brine to be treated is initially fed into a feed tank for a 5-to-10 minute residence during acid treatment. The acidified feed is then pumped through a heat exchanger: (1) which raises the temperature of the incoming flow to the boiling point. After the water passes through a noncondensible gas scrubber (2), it enters the evaporator sump (3). Brine from the sump is pumped to the top of the heat-transfer tubes (4), where it is released to fall as a film inside of the tubes. A portion of this falling film is vaporized. In a vapor-compression thermodynamic cycle, the vapor is then compressed (5) and introduced to the shell side of the tube bundle. (6). The temperature differential between the vapor and the brine film causes the vapor to condense as pure water (7). The concentraton brine slurry is continuously withdrawn (8) from the sump for final dehydration in a solar pond, mechanical dryer, or separator. The total energy consumption is in the range of 30 to 40 Btu per pound of feed water.

Membrane processes are capable of acceptably high levels of brine concentration. However, flux-rate reduction with increasing brine concentration, and membrane fouling are problems which have not been satisfactorily overcome. Insufficient information is available to judge the performance, reliability, costs of membrane electrodialysis, ion exchange, freezing, electrochemical oxidation (of ferrous iron), ozone oxidization or any other process for the treatment of steam electric powerplant waste waters.

Technology Specific to Powerplant Waste Waters (General)

The control and treatment technology for the discharge of chemical wastes from a steam electric powerplant involves one or more combinations of the following techniques:

(1) Elimination of pollutants by:
    a) process modifications

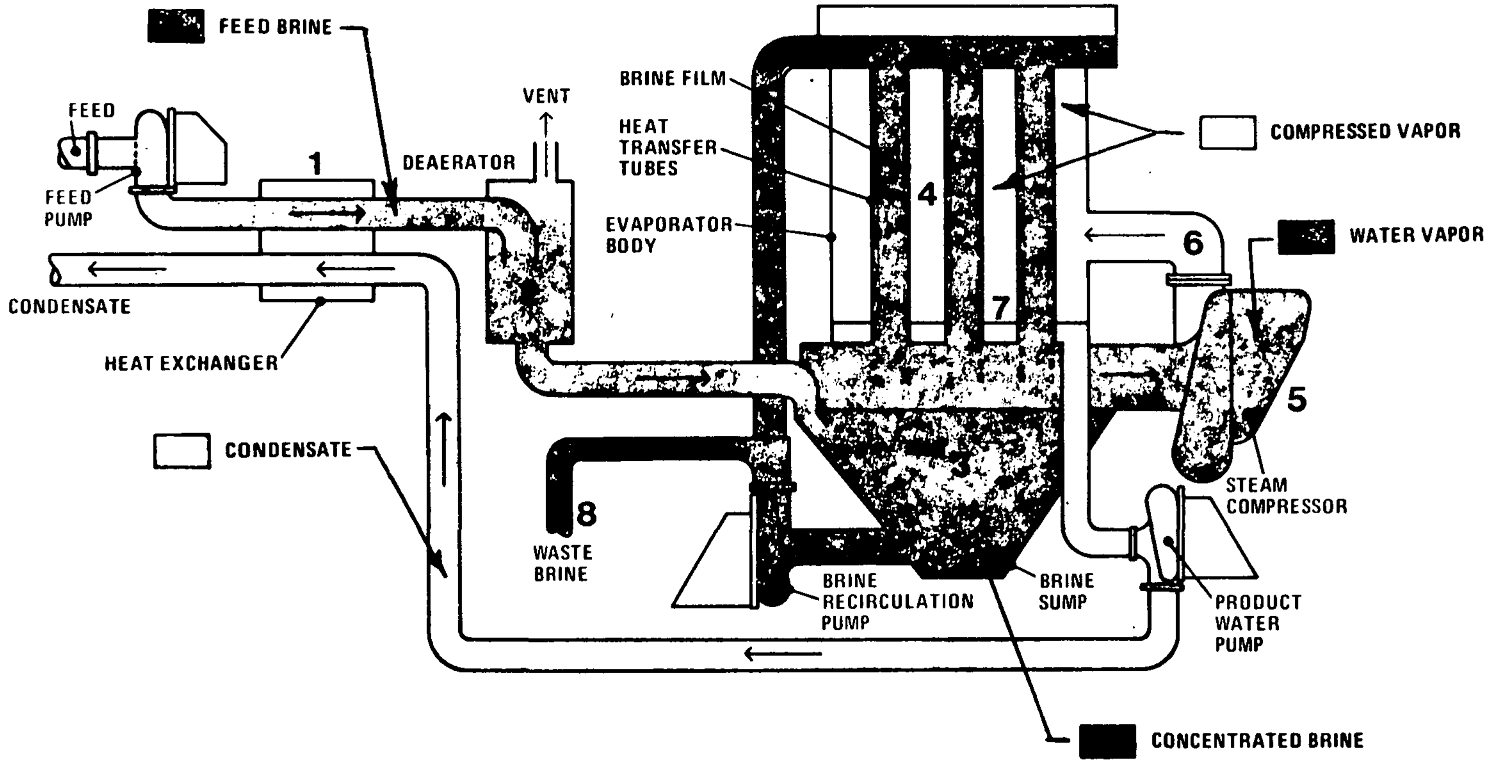


Figure A-VII-7 Brine Concentrator, Resources Conservation Co.

b) material substitutions
c) good housekeeping practices
(2) Control of waste streams by maximum reuse and conservation of water
(3) Removal of pollutant from waste stream

The following is a summary,exerpted from reference 444, of the principal methods of powerplant waste disposal which are currently available:

1. Controlled Release to a Waterway. A common practice is to neutralize the acid or alkaline waste and release it via the circulating water discharge so that dilution of 5,000 or 10,000: 1 is realized.

2. Collection of Spent Solvent in a Retention Basin for Neutralization and Sedimentation Before Controlled Release. This method has the advantage at some sites that acidic wastes can be reacted with alkaline wastes so that no additional chemicals are required for neutralization; but the applicability of this method is affected by site characteristics such as availability of space and the nature of other wastes generated at the site.

3. Impoundment on Company Property. Some utilities particularly in the Southwest impound their waste in lagoons on site. These lagoons or holding basins are suitably constructed so as to prevent the escape of the liquid by any means other than evaporation. This method is of course possible only at locations where sufficient land is available and where climate conditions are suitable.

3. Off-Site Disposal. In some cases chemical wastes have been trucked off-site to a commercial waste disposal firm. Costs range up to 12 cents per gallon depending on waste compositions and distance. Barging to deep sea is another method which has been used by utilities along the coast. This method is costly and generally cannot be economically justified for volumes under 200,000 gallons. In general, economic and environmental considerations limit the usefulness of off-site disposal to special situations.

5. Solidification of Wastes. Some utilities have experimented with solidifying the spent solvents. This entails engaging an outside vendor who transports a van equipped with solidifying reagents, pumps and other paraphernalia; scheduling is important and costs range from 5 to 17 cents per gallon. This method can be used where solid disposal is possible in a landfill area, gully, abandoned mine, etc. Final solid volume is about 5% more

than starting volume of the waste due to the solidfying chemicals added.

6. Combustion or Incineration of Wastes. Within the last year or two, one utility has introduced a new means of disposal of certain spent solvents. A small number of jobs have not been performed by several utilities in which Vertan 675 or the ammoniated citric acid from the CitroSolv process, both at pH of 9.2 - 9.5, have been drained from the boiler and combusted in an adjoining boiler. The method has been to spray the spent solvent into the furnace of an operating boiler at a rate of 50-100 gallons per minute. Interestingly, no deleterious air pollution effects have been associated with this procedure. In fact there appears to be some reduction in emissions of nitrogen oxides and dulfur dioxide. It is questionable whether this method could be used on neutralized hydrochloric acid or ammonium solutions. There is a distinct possiblity that the halogen ions could attack the austentite steel alloy tubes in the superheater and reheater.

In order to select and implement an efficient waste management program, it is necessary to evaluate the control and treatment techniques corresponding to specific factors applicable in each case.

In this section alternate control and treatment techniques and their limitations are evaluated for different chemical waste streams. Advantages and disadvantages are presented. Based on the reported data, industry-wide practices and exemplary facilities are indicated.

Chemical wastes can be discussed in three general groups (continuous wastes, periodic wastes, and wastes whose characteristics are unrelated to the powerplant operations) even though, for the purposes of guideline development, a classification by volume would be appropriate. The continuous wastes are those directly associated with the continuous production of electrical energy. They include condenser cooling water discharge (for once-through systems) or blowdown (for closed systems), water treatment plant wastes, boiler or PWR steam generator blowdown, discharges from house service water systems, laboratory, ash handling systems, air pollution control devices, and floor drains. The periodic wastes are those associated with the regularly scheduled cleaning of major units of equipment, usually at a time of plant or unit shutdown. Those include spent cleaning solutions from the cleaning of the boiler or PWR steam generator tubes, boiler fireside, air preheater and condenser cooling system, and other miscellaneous equipment cleaning wastes. The final group of wastes includes drainage from coal piles of coal fueled plants, drainage from roof and yard drains, run-off from on-site construction and sanitary wastes. Control and treatment of discharges from systems involving high-level or low-level rad wastes are not known to be practicable due to the possible adverse affects which might arise from concentrating the radioactive materials in the treatment operation.

Continuous Waste Streams

Cooling Water Systems

References 357, 387-389, 418 and others are a source of considerable information cn control technology for cooling water systems.

Maintaining condenser tubes or other heat exchange equipment with an inherent new-tube cleanliness is most important to keep the efficiency and economics of the process at its designed level. The cost penalty of tube fouling increases porportionately as the cleanliness decreases. If allowed to continue, an unscheduled outage may be rquired to clean the tubes, thereby losing production and further compounding additional costs. The objective is to maintain the cleanliness factor at an acceptable level by one or more methods that can be:

1. Continuous and complete chemical conditioning of the cooling system while operating

2. Chemical cleaning of the heat exchanger tubes at the scheduled outage

3. Mechanical cleaning of the tubes while operating with equipment utilizing either sponge rubber balls or brushes, slightly over-sized to pass through the tubes

4. Mechanical cleaning of the tubes at a scheduled otuage

5. Mechanical cleaning as in Item 3 but without extensive chemical conditioning as intended in Item 1.

To discuss methods of cleaning condenser systems might imply that condenser tubes become fouled quite often either from chemical or biological deposits or in combination. In some instances this is true; there are electric generating plants that consider it necessary to clean condenser tubes on a weekly basis. Others do so less frequently, such as semi-annually or annually. Yet other plants can operate and maintain the designed cleanliness factor without having to clean tubes but once in 10 to 15 years. For many plants the elementary difference may lie in the attitude toward maintaining a proper quality program for the cleanliness of circulating water systems, whether once-through or recirculating incorporating a cooling tower.

Chemical Conditioning

Chemical Conditioning of Once-Through Systems

At those generating plants where once-through cooling is used, chemical conditioning of the circulating water for corrosion and scale control is never practiced. The costs would be prohibitive considering the large volume of water to be treated. Mainly the only chemical needed is a biocide to minimize fouling of the condenser tubes, tube sheets, and water boxes by bacterial slime or other growths. Generally the biocide is predissolved chlorine gas, applied one or more times a day over a period of 15 to 30 minutes to produce a residual of about 1 mg/l or more at the condenser inlet. Chlorine is the only biocide that has proved to be effective and most economical at many plants.

Frequency, dose, and duration of the chlorination cycle is variable, depending on water quality and temperature. Four 30 minute periods a day is not an unusual program. Dosage is controlled by maintaining a residual level at the condenser outlet at a level of about 0.5 mg/l. Time interval between application and sampling may be in the range of 20-30 seconds when chlorine is applied just ahead of the condensers to 3-5 minutes when it is applied at the intake.

Water quality has a two-fold effect on this operation. The poorer the quality, the greater the chlorine demand thus increasing dosage requirements. The food supply in poor quality water accelerates the growth of organisms in the condenser tubes between chlorination programs thus increasing the duration of the chlorination cycle and/or frequency to maintain satisfactory control. The popular definition of the term "chlorine demand" is that it is the defference between dose and residual. To be of meaning, it must be properly expressed in terms of type of residual, temperature, pH, and time of contact between dosing and residual measurement. It is the time element that is so frequently overlooked and which poses a problem in very short time-of-contact situations.

Consider, for instance, that demand figures under otherwise identical conditons were compared for 30 seconds vs 30 minutes in water containing ammonia nitrogen. Assuming 80% of the 30 minute demand will be satisfied in the first 5 minutes, much of this will occur in the reaction with hypochlorous acid before the formation of the slower reacting chloramines. When this occurs, the rate of satisfaction of the demand falls off rapidly. When demand results are based on the addition of preformed chloramines, the difference is so drastic that chlorine demand figures require the added dimension of type of available chlorine being used. Misunderstood by many is that ammonia does not constitute chlorine demand until the ratio of chlorine to ammonia exceeds approximately 10:1.

Further complicating this issue in the case of short contact times is that sampling and accurate residual determination may consume much more time than the actual contact time. This error probably accounts for many powerplants using a larger dosage than necessary in their cooling water.

The preparation of environmental impact statements for operating systems for new power stations led to the study of existing plants for probable operating results. Some multiple units employing once-through cooling water systems were found to seldom discharge any appreciable residual chlorine to the receiving water where the station configuration was similar to that shown in Figure A-VII-8 Procedure provides for chlorination of one unit at a time on a program similar to that described below. The discharge from each unit is diluted by that from the three not being chlorinated. The effect of dilution and exertion of chlorine demand by the unchlorinated water occurs almost simultaneously.

Data from several power plants are illustrated by Table A-VII-2 The data were collected by trained technicians familiar with powerplant chlorination practices, using amperometric titrators. The scope of the test work did not include complete analysis of the water but, based on the foregoing comments regarding chlorine dosage, ammonia, and time of contact, the differences in water "quality" are evident. Stations A and B are nearly idential in layout to that shown by Figure A-VII-8, but located on two different rivers. The points of application are close to the condenser water boxes in both power plants. Plant C has a common discharge canal and several units were running at the time of the test. All points of chlorine application are at the intakes serving the units and one unit is treated at a time. Plants D, E, and F are included to illustrate the

Figure A-VII-8 Typical Powerplant Cooling Water Circuit[418]

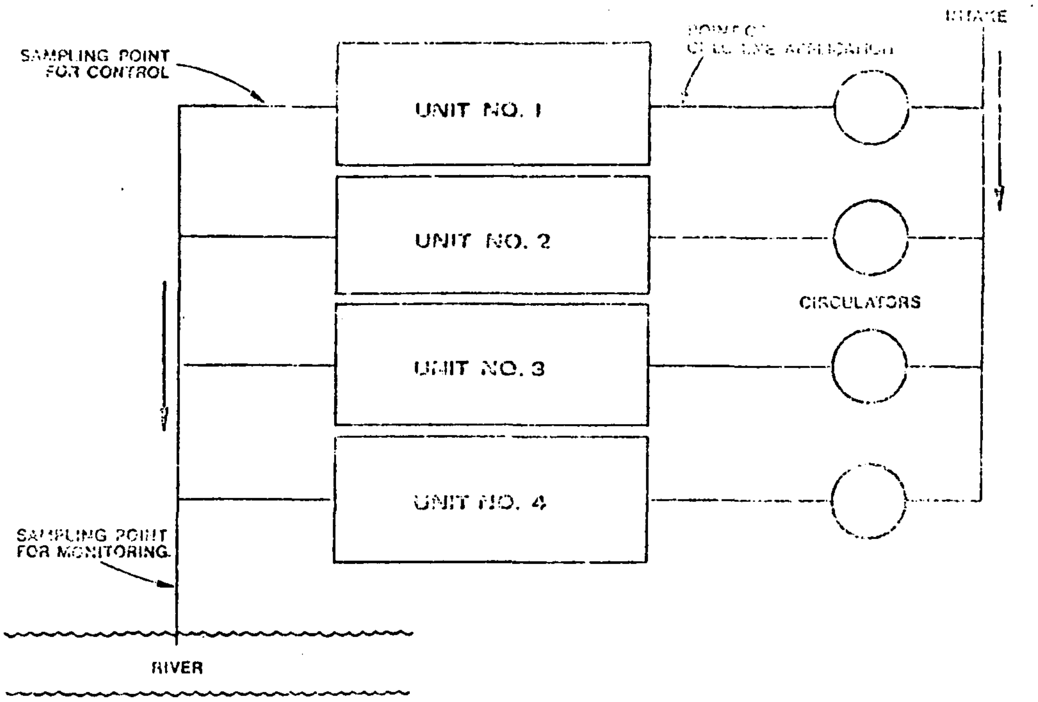


Table A-VII-2

OPERATING DATA
TYPICAL POWER PLANT COOLING WATER CHLORINATION
OPEN, ONCE-THROUGH, COOLING SYSTEMS
(MARCH-MAY 1973)

Reference 418

PLANT	TIME OF CONTACT (SECONDS)		DILU-TION RATIO	Cl_2 DOSE (mg/l)	CHLORINE RESIDUAL (mg/l)*				CHLORINE TREATMENT	
					Cond. Disch		Effluent			
	Thru Cond.	To River			Free	Total	Free	Total	(X/Day)	(Min.)
A	30	180	3:1	1.52	0.65	0.84	0.06	0.19	1	30
B	61	174	3:1	1.76	0.65	0.82	0.07	0.10	1	30
C	52	78	4:1	2.00	0.03	1.50	0.00	0.20	3	20
D	115	624	4:1	3.80	0.50	1.60	0.00	0.20	3	120
E	44	225	1:1	7.00	1.20	2.20	0.70	1.20	5	30
F	63	591	5:1	7.00	1.10	2.00	0.00	0.05	1	45

*Chlorine residuals by amperometric titrator.

differences which can be encountered on the same river over a distance of less than 3 miles. Plant D is the upstream plant and Plant F is the farthest downstream. The points of chlorine application are at the intakes in all cases and the plants supervisory and operating personnel have many years of experience with chlorination. The purpose of Table A-VII-2 is to illustrate, as accurately as possible, actual operating conditions in power plants where organic growths in condensers are being successfully controlled, and to show the effects of dilution and added "chlorine demand" on the total residual chlorine in the plant effluents.

The data were collected in plants having individual units varying in age from 5 to 30 years, and unit sizes from 60 Mw to 750 Mw. After one studies the data one may reach conclusions such as (a) Plant D is overchlorinating in terms of either frequency or duration; (b) Plant E is overchlorinating in terms of residual level and frequency. Extensive test work is being conducted at both plants to determine the optimum chlorine treatment required.

It is not unusual to observe two units in a single power plant requiring different chlorination schedules. The geometry of the cooling water system; size and design of condensers; physical condition of the tube surfaces; as well as water quality have an influence on the chlorine residual levels and schedules of operation required to maintain comparable unit performance. Obviously, the condition of a river can change substantially within a few miles as indicated by Plants D, E, and F.

A conclusion is that substantial savings in chlorine dosage can be achieved by application as near the condenser inlet as possible while still maintaining control levels necessary to maintain cleanliness. This in turn results in residual chlorine consisting to some major degree of hypochlorous acid, a form most easily reduced to chloride by chlorine demand of water from adjacent units.

Another study was made on the blowdown of a cooling tower serving a power plant employing intermittent chlorination of recirculated water for slime control of the condensers. Blowdown was continuous. Chlorination of the unit served by this tower is programmed for four times a day. Residual in the blowdown for one cycle (typical of the other three) is shown in Figure A-VII-9. Makeup to this tower is discharge from a cooler using water from another system in the plant, also being chlorinated with a similar program but staggered from the tower under study. This accounts for the momentary increase close to the end of the cycle. This curve shows

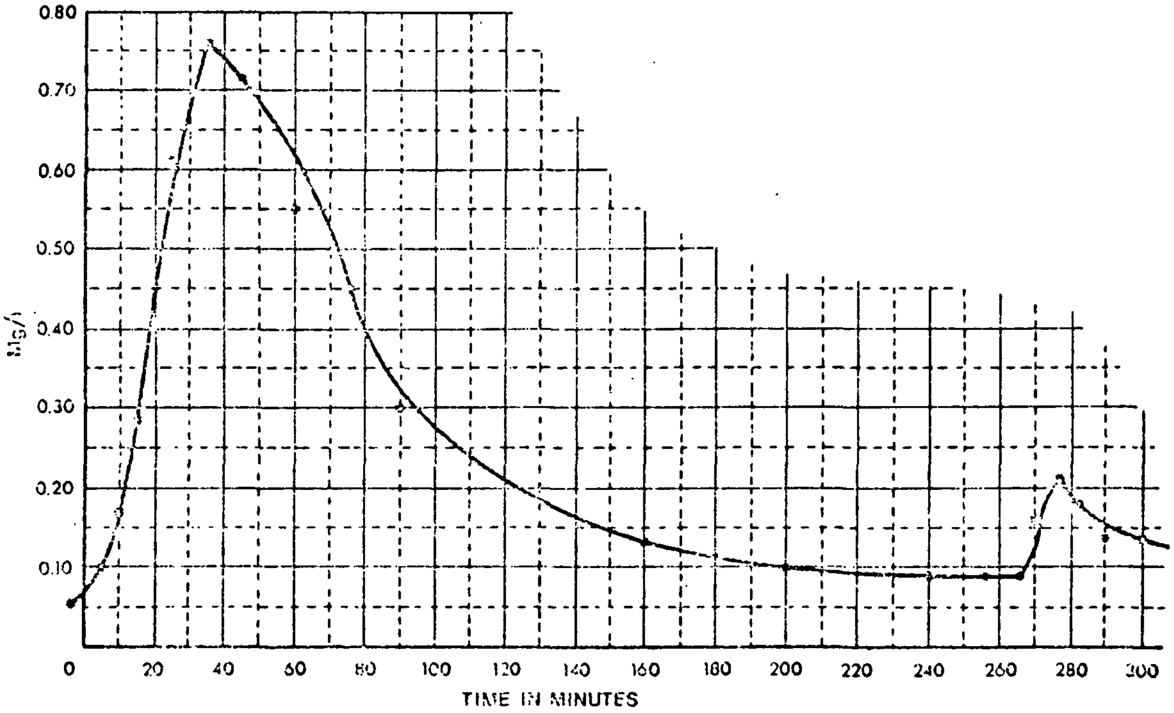


Figure A-VII-9 Concentration of Residual Chlorine in Cooling Tower Blowdown Versus Time 418 only total residual chlorine. Other data on this tower indicated that at peak values as much as 65% of the total was free available chlorine, declining gradually and disappearing when the total dropped to approximately 0.2 mg/l.

Draley,[425] in developing data for an equation to predict decay rate, plotted the residual values during two chlorination cycles and beyond in a power plant with a natural draft tower. The shape of the curves for the cooling tower basin return was nearly identical to Figure A-VII-9. Peak value for one run was about 0.3 mg/l total residual. No free available chlorine was found. A second run with a peak value of about 0.5 mg/l total yielded less than 0.1 mg/l free available chlorine.

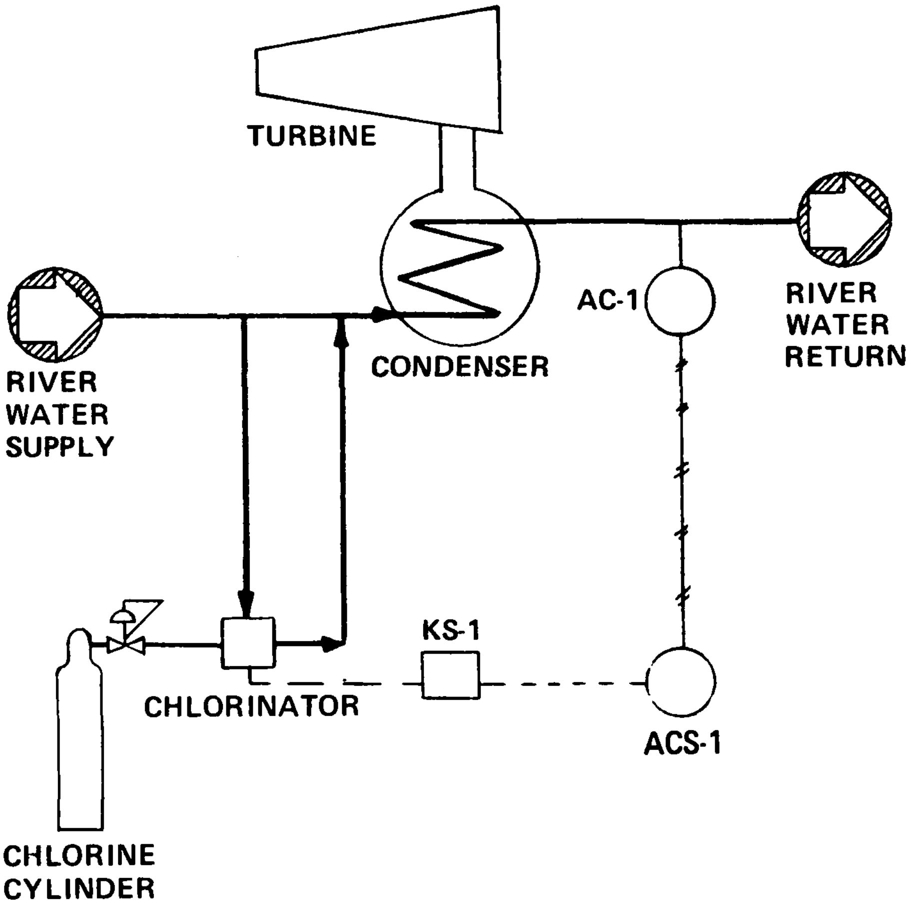
The similarity of the shape of the curves is noteworthy in view of the differences in the sytems. The data in Figure A-VII-9 represents a cooling water which (1) has some residual remaining from the previous cycle, (2) the total value was higher, (3) sampling was in the tower blowdown instead of the cold water return, and (4) the tower was of the induced draft instead of natural draft (hyperbolic) type.

In another study, Nelson[326] in developing a mathematical model to predict residual chlorine levels in cooling tower blowdown streams, expressed residual as negative chlorine demand. When the plot of the resulting curve is simply inverted, it closely resembles those mentioned above. The point is that the reliability of predictability seems firmly established. The factors involved in the decay rate of the recirculated cooling water after the chlorination cycle is ended are: (1) blowdown; (2) evaporative losses; (3) light catalyzed decomposition of free chlorine; (4) chlorine demand of the system; (5) cooling system volume; (6) recirculation rate; (7) chlorine demand of the makeup; (8) atmospheric contamination; and (9) decomposition products of basin sediment deposits.

Since all of these effects occur simultaneously, it seems impossible to segregate and identify them individually. Fortunately, from the results cited above it also seems unnecessary. One of these, evaporate losses, has been cited as a possible air pollution problem. The volatitity of chloramines has long been known to exceed that of free available chlorine. This is particularly true of nitrogen trichloride and, to a slightly lesser degree, dichloramine. In fact, aeration is frequently used to remove these compounds following ammonia nitrogen oxidation (breakpoint chlorination). The most predominant species, monochloramine, is much less subject to loss. In studying waste treatment plant effluents, where the residual usually consists of all chloramine, Kothandaraman and Lin[426] reported no loss of residual chlorine due to air agitation of 5600 cfm/1000 cu ft for 30 minutes at residual levels above 2 mg/l. Thus it would appear that evaporative losses of combined chlorine which could be expected to be nearly all monochloramine in a cooling tower and subsequent air contamination are not factors of consequence. Free available chlorine is subject to reduction by sunlight but not by volitilization.

Excess total residual chlorine discharge can be minimized by monitoring free available chlorine concentrations in the discharge stream and providing feed-back control on chlorine addition. Commercial monitoring and controlling instruments are available from at least two major suppliers. The analyzers furnished by both of these firms involve an amperometric analytical method which utilizes two electrodes to measure the current generated by the presence of chlorine. One of these firms advises that the reliability of this type of analyzer and control system is generally concluded to be approximately 0.1 mg/l. However, the analyzer must be calibrated in the field at least once per week by using a titrator, and consequently the ultimate reliability of the system depends upon the conscientiousness of the operating and/or maintenance personnel. These analyzers can be used to monitor either total residual chlorine or free available chlorine by making a change in the chemical composition of the buffer solution.

As shown in Figure A-VII-10, chlorine can be regulated by feedback instrumentation. The chlorine feeder is activated manually or by a timer. Chlorine is then added to the cooling water before it goes to the condenser. Cooling water leaving the condenser flows to the cooling pond or to the receiving water body. Chlorine level in the discharge is monitored by chlorine analyzer AC-1. When chlorine reaches 0.1 mg/l the analyzer opens ACS-1 which shuts down the feeder until it is restarted manually or by timer KS-1. This type of system is not in general use in the industry at this time, but is common practice in municipal sewage treatment plants. Intermittent programs of chlorine or hypochlorite addition can be employed to reduce to total chlorine residual discharged. A further technique to reduce the total residual chlorine discharged is to employ chlorination at periods of low condensor flow for a unit. If only one unit at a time at a multiunit station is chlorinated, the concentration of total residual chlorine in



LEGEND:
AC-1: CHLORINE ANALYZER
ACS1: CHLORINE FEEDER CONTACTS
KS-1: CONTROLLER (TIMER OPTIONAL)
——— : FLOW PATH
—●—●—●— : OPTIONAL FLOW PATH
– – – – : INSTRUMENT SIGNAL

FIGURE A-VII-10CHLORINE FEED CONTROL ONCE-THRU CONDENSER COOLING SYSTEM the combined effluent from the station is reduced. Chlorination can further be employed at times in harmony with more favorable receiving water conditions.

Controlled addition of chlorine can also be achieved without the daily use of monitoring instruments. Sampling and laboratory analysis can be employed for a number of days until a correlation is established between chlorine addition characteristics (schedule, rate, duration) and the effluent total residual chlorine concentrations. Subsequent use of the correlation with no effluent sampling, except for occasional checks, may be satisfactory in many cases.

Figure A-VII-11 illustrates, in simplified form, a typical once-through system for a nuclear or fossil-fueled plant. It is impossible to cover the many variations in layout which are being developed by engineers to accommodate the rapidly changing technology, power plant equipment design, and growth in unit size, However, regardless of the complexity of the system, all of the cooling water must be chlorinated.

To minize the level of residual chlorine in the effluent, it is logical to select points of chlorine application and design the control system to take maximum advantage of dilution effects in the discharge canal(s). This requires revisions in what has been considered standard practice. Referring to Figure A-VII-11, it has become a common practice in recent years to chlorinate the plant service water and or auxiliary cooling water as separate systems tor two reasons which remain valid: (1) Chlorination of the service water often requires a schedule of treatment and chlorine dosage level different than needed for the main condensers; and (2) modern intake designs and pump locations make it very difficult to design and locate a single set of diffusors to chlorinate all the water entering the plant.

Therefore, chlorination of the station service water, auxiliary cooling water, and emergency cooling water (if any) remain as separate functons which may be controlled to take advantage of dilution in the water return system.

For the past twenty-five years, with few exceptions, condenser cooling water has been chlorinated at the intake structure. Again, with few exceptions, chlorination was programmed on a unit basis as indicated by the plants listed on Table A-VII-2 There are several sound reasons for this practice: (1) The chlorine solution piping system is short and of simple design for most applications; (2) The electrical control system is the least complicated possible,

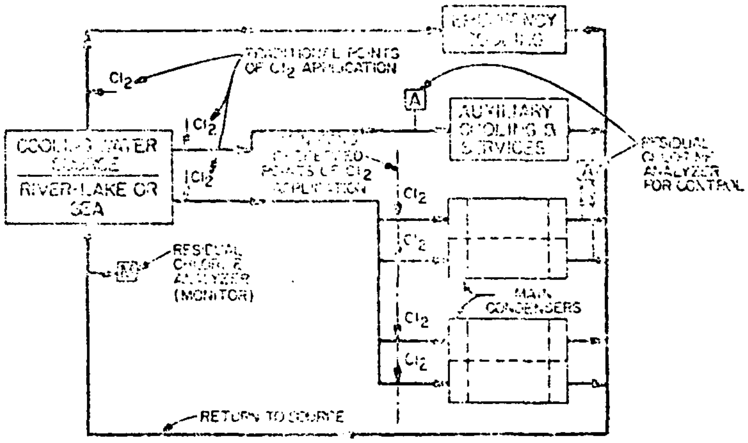


Figure A-VII-11 Typical Power Plant Once-Through Fresh or Salt Water Cooling System-Points of Chlorine Application (Reference 418) often being limited to one or two program clocks and simple chlorine feed step rate controls; (3) If marine growths and shelled organisms are anticipated as a problem the diffusors are located ahead of the bar racks instead of in the screen wells[428] and the controls remain essentially the same as indicated above; and (4) The chlorination equipment and chlorine handling system are located near the water intake structure which is generally several hundred feet from the power station proper.

Generally new condensers are served by at least two cooling water flows and six are not uncommon. Therefore, if the points of chlorine application are located in the piping system just ahead of the inlet water boxes as illustrated on Figure A-VII-11 and the chlorine control system designed to treat the unit flows (four illustrated) one at a time in sequence, the chlorine residual in the treated water will be diluted by a factor of one, three or five depending on the system design.

The auxiliary cooling systems are treated on a separate program which is timed to operated when the main condenser flows are not being treated. The ratio of auxiliary water flow to the total main condenser flow is on the order of one to ten or more and it is unlikely that a measurable chlorine residual from this source would be detected in the plant effluent.

There are existing powerplants which have been using this type of control for over 15 years though the original designers had no thoughts regarding dilution of chlorine residual in the effluents at the time the plants were built. Experience with chlorination in these plants has been excellent. Based on work done several years ago and recent test data presented herein, there are several advantages which should be self-evident: (1) The short time of contact minimizes both the chlorine dose required and the level of the combined chlorine residual in the water as it passes through the condenser; (2) Since a large percentage of the total chlorine residual in the condenser during treatment is free (HOCl) the duration of each treatment can also be reduced. However, duration of treatment and frequency are both dependent on the rate of growth of the fouling organisms and frequency, in particular, may require change with the season of the year; and (3) The effect of dilution on the total chlorine residual in the plant effluent is obvious.

Mechanically and electrically, the chlorination system becomes more complicated but with compensations. The size of the chlorination system in terms of chlorine feed rate is reduced by a factor of two, four or six. This saving in cost is probably offset by the additional solution piping and controls which are required. The chlorine control equipment and handling system may still be located remotely with respect to the power plant. The total amount of chlorine used will be reduced to the practical minimum for the particular plant and units.

There are three points which should not be overlooked though, in most cases, they would not be considered disadvantages: (1) Long cooling water lines ahead of the condensers are unprotected in terms of organic fouling: (2) The intake structure and cooling water system up to the points of application are subject to fouling by Bryozoa and shelled organisms if brackish water or sea water is the source of cooling water, and (3) Service water and/or auxiliary cooling water must be treated in its entirety, usually at the intake, because of the relatively complicated cooling systems involved.

The current trend in the U.S. is away from large, open, once-through cooling water system except those involving man-made lakes built for the purpose of sea water cooled projects. For practical purposes, the modern spray canal can also be considered as an open system in terms of chlorination though actual experience is limited to very few installations at this time. One spray canal user reported during August, 1974, that no detectable chlorine residual returned to the point of chlorine application. The blowdown connection is on the cold water end of the canal and ahead of the point of chlorine application. No measurable residual chlorine is in the blowdown water at any time. The constants for this particular system are:

Recirculating rate - 2 @ 185,000 gpm treated one at a time (2 Program Control)

Chlorine Treatment - 20 minutes once per day - each point

Chlorine Dosage - 2.7 mg/l

Total Chlorine Residual - 0.5 to 1.0 mg/l at condenser inlet

Points of Application - Ahead of circulating pumps

Dilution Ratio - 1:1

Contact Time in Canal - 5 hours

Makeup Water Flow - 20,000 gpm

One plant, on once-through circulation with sea water, changed to acrolein from chlorine primarily because acrolein (CH_2CHCHO) was more effective in controlling grass growth that matted the screens at the intake canal. After some months it was noted that condenser tube fouling had increased; an inspection disclosed that the acrolein was more effective than anticipated for biological fouling; the tubes and the tube sheet were free of slimes. The foulant in heat transfer was found to be a paper thin layer of carbonate scale that previously had been kept under control by the slight depression of pH when chlorine was used. The acrolein was incapable of reacting with the carbonate. The plant then changed back to chlorine. Of incidental interest, acrolein in the amount needed as a biocide has zero toxicity to fish. Typical of many others, this plant has not had to clean condenser tubes either manually or chemically after 10 years operation. The biocide quality control program has been adhered to and has maintained to desired cleanliness factor. The related program of reversing flow through the condenser was incorporated in the original design and is routinely utilized to dislodge some of the potential foulants.

Chemical Conditioning in Recirculating Systems

In an evaporative cooling tower system the dissolved solids will become increasingly concentrated above the amount of dissolved solids in the makeup water to the system because of evaporative cooling losses. By blowdown from the system the concentrated solids are maintained at a prescribed level to prevent chemical precipitation and scaling. Chemical conditioning is used supplementally to minimize any scaling or corrosive tendency. Shock treatment with a biocide completes the conditioning program. Chemical conditioning with proper quality control will maintain the designed terminal temperature difference at the condenser for many years. Corrosion rates will be less than 1.0 mil per year.

Tables A-VII-3 and A-VII-4 show the average operational values for two types of chemical conditioning of cooling tower systems that are operated without on-line mechanical tube cleaning equipment.

The monitoring of chlorine in the blowdown stream can be achieved in a manner similar to that described for the once-through system.

Table A-VII-3

CHEMICAL CONDITIONING OF COOLING TOWER SYSTEM USING CrO_4 - PO_4 387

Untreated River Makeup to Tower		Cooling Tower System	
	mg/l		mg/l
Ca as $CaCO_3$	200	Ca as $CaCO_3$	800
Mg as $CaCO_3$	66	Mg as $CaCO_3$	264
HCO_3 as $CaCO_3$	129	HCO_3 as $CaCO_3$	15
Cl as Cl^-	455	Cl as Cl^-	1,820
SO_4 as SO_4	60	SO_4 as SO_4	712
		CrO_4 as Cr	12
		PO_4 as P	4
		pH	6.5

Controllable limits in tower system: pH 6.4 to 6.6; total alkalinity 15 to 20 mg/l; calcium as $CaCO_3$ 1000 mg/l max; hexametaphosphate 6 to 10 mg/l; CrO_4 25 to 30 mg/l.

Table A-VII-4

CHEMICAL CONDITIONING OF COOLING TOWER SYSTEM USING ORGANIC PHOSPHATE 387

Untreated Well Water Makeup to Tower		Cooling Tower System	
	mg/l		mg/l
Ca as $CaCO_3$	232	Ca as $CaCO_3$	968
Mg as $CaCO_3$	40	Mg as $CaCO_3$	212
HCO_3 as $CaCO_3$	216	HCO_3 as $CaCO_3$	196
SiO_2 as SiO_2	28	SiO_2 as SiO_2	150

Controllable limits in tower system: pH 8.4 to 8.6; total alkalinity 175 to 225 mg/l; calcium as $CaCO_3$ 1000 mg/l max; silica as SiO_2 180 mg/l max; organic phosphate 20 to 30 mg/l.

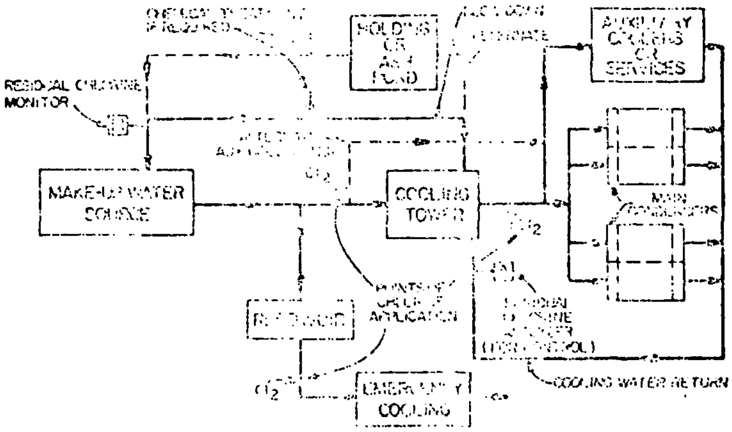
Further potential methods of reducing or eliminating residual chlorine levels in the blowdown are as follows:[376]

a) Installing residual data feedback equipment into the chlorine feed system.
b) Practicing split stream chlorination (splitting the condenser flow into separate streams which are chlorinated one at a time).
c) Reducing the chlorine feed period, if possible.
d) Reducing the initial residual chlorine level in the condenser effluent.
e) Increasing the water volume of the cooling tower. This alternative may not apply to existing cooling towers because it involves the system design. The alternative can apply to systems on the engineering drawing boards. This alternative may have other advantages--such as an extra supply of water for fire protection.
f) Cutting off the blowdown when residual chlorine appears in the sump. The blowdown flow can resume after the residual is dissipated by the flashing effect and the makeup water chlorine demand. The length of time during which the blowdown can be eliminated is a function of the system's upper limit on dissolved solids.
g) Mixing the blowdown with another stream which has a high chlorine demand.

Figure A-VII-12 illustrates a typical recirculated fresh water cooling system and a few of the ancillary systems or variations which are often encountered. The total residual chlorine curve with respect to time (decay) is predictable for a cooling tower system. Location of the points of chlorine application is traditionally in the tower basin discharge canal or ahead of the recirculating pumps in a sump. The several sets of data in the references were collected from tower systems intermittently chlorinated using the traditional points of application. At this time a recommendation cannot be made that the location of the point of application be changed since dilution or lowering of the chlorine residual returning to the tower would undoubtedly result in accelerated fouling of the tower fill.

If the makeup water is first used to cool auxiliaries, it should be chlorinated following the same principles as used for an open system but with the program set so that it does not coincide with treatment of the recirculating water.

The blowdown should be taken from the tower basin ahead of the point of chlorine application but it has been found that



TYPICAL

RECIRCULATED POWER PLANT COOLING WATER SYSTEM

(COOLING TOWER)

POINTS OF CHLORINE APPLICATION

418

Figure A-VII-12

this is not the case for many existing cooling tower systems. If the blowdown is used to sluice ash, the chlorine residual is lost in the ash pond. Similarly, a holding pond could accomplish the same result if the time of retention is long enough. At the very least, a holding pond smooths out the peak levels of residual chlorine and reduces the level to one which can be easily eliminated by controlled chemical dechlorination.

If the blowdown is returned to the receiving body of water direct, there are two alternatives: (1) Close the blowdown valve during the chlorination cycles with suitable time delay controls set to match the time-residual characteristics of the system; and (2) Controlled chemical dechlorination of the blowdown in synchronism with the chlorination program controls and with time delay as described above.

Experience indicates that a successful chlorination cycle for the average fresh water power plant cooling tower system is two treatments per day; each treatment approximately ten minutes longer than the turnover time; and with the chlorine feed rate set to build up a total residual chlorine level of 0.5 mg/l in the water returning to the tower at the end of the chlorination period. Note that this statement is based on current experience; not on tests designed to determine the minimum treatment which will produce the desired results; viz., a clean system. For example, it should follow that a lower residual maintained for a longer time would give a similar result, or carried to the logical conclusion, a very low total chlorine residual carried in the system continuously would be equally effective.

There are several power companies in the U.S. which use continuous chlorination of cooling tower systems but at residual levels on the order of 0.3 to 0.5 mg/l. No experiments have been performed to determine the practicability of variations in the chlorine treatment of cooling tower systems; largely because no one wishes to risk the need for removing a large unit from the line to manually clean both the condenser and the cooling tower.

Experience with recirculated salt water systems is practically nil but the makeup water to a cooling tower system should be chlorinated continuously if the water supply is either brackish or salt. The total residual chlorine level should be the minimum which can be realiably controlled, i.e., between 0.1 and 0.2 mg/l. The treatment will prevent infection of the recirculated water system by

Bryozoa and shelled marine organisms such as barnacles and mussels.

Controlling the usual organic slime growths in once-through salt or brackish, water-cooled heat exchangers requres the same chlorine treatments as needed for fresh water. Variations in residual chlorine level, length, and duration of treatment are caused by pollution factors, the same as for fresh water, and the need to control the accumulation of more resistant marine growths.

Using the open system, salt water experience as a reference, it follows that continuous low level chlorination of the makeup water will eliminate the marine organisms as a problem and certainly reduce the bacterial infection and chlorine demand added to the recirculating water via the makeup water. However, it is doubtful that it would be practical to chlorinate the makeup water heavily enough for the chlorine residual to be effective in the condensers or on the tower structure.

The standard intermittent chlorination of the recirculating water will be the same as described for a fresh water system but undoubtedly the total amount of chlorine used will be reduced. The cooling water is an excellent air scrubber and algae as well as "chlorine demand" removed from the air remain as fouling sources to be contolled by chlorination of the recirculating water.

The amounts of pollutants discharged in blowdown can be reduced by reducing the blowdown flow. This reduction in flow can be achieved by substituting more soluble ions for scale formers. Similarly, the use of organic sequestering agents such as polyolesters and phosphonates can be used to reduce blowdown flow rates.[336] These then become pollutants in the blowdown.

Water treatment chemicals are used to control several problem areas. The use of these chemicals has been greatly reduced by the substitution of plastic or plastic-coated cooling tower components. The plastic shows considerable resistance to microbiological attack, corrosion, and erosion. Many new installations using cooling towers are going this route. Where water treatment is necessary, several chemicals are being used to control the various problem areas associated with the cooling towers.

Of the commonly used biocides, chlorine or hypochlorite or nonoxidizing organic compounds such as chlorophenols, quaternary amines, and organo-metallics such as organotin compounds, organosulfur, and organothiocyanate Table A-V-18 are most frequently employed. They are all used to prevent deterioration of tower wood, loss of heat transfer efficiency, general fouling or plugging arising from microbial growths, and corrosion that results from microbial attack, Organotin must be formulated with quaternary ammonium and other complex amines to produce a synergistic effect and to be dispersible. Chlorophenols, as soluble potassium and sodium salts, are more persistent than free chlorine and remain in systems longer. Common chlorophenols include: 2,4,5-trichlorophenate; 2,4,6-T; 2,3,4,6-T; tetrachlorophenol; and pentachlorophenol. Organosulfurs are noted for low toxicity to animals, yet effective action against bacteria, fungi, and especially sulfate-reducing bacteria. Quarternary and complex amines are effective wetting agents and destroy microbial agents by surface-active properties; these are the least toxic of all antimicrobial compounds to animals, although they may form and so cause anesthetic problems. The organothiocynates, the most modern of the nonoxidizing biocides, are widely effective. Oils, organic chemicals, water hardness, and other materials seem to cause little reduction in their effectiveness, especially if they are combined with chlorophenols. The nonoxidizing biocides are used whenever the problems are rather severe and where the use of free chlorine is not acceptable. Typical concentrations for continuous use are 1 to 25 ppm; higher (200 ppm or so) if applied in periodic treatments. Elemental chlorine is an oxidizing agent and can cause rapid deteroriation of wood.108ee

The use of biocides that contain mercury, arsenic, lead, or boron may be limited by more stringent regulations on their release to the environment than most of the compounds previously discussed. These are rarely if ever used now; however, a review of label names in Table A-V-18 reveals that the potentially harmful materials, copper and thiocyanate ions, are present in some commercial compounds. Tin is probably also questionable as far as environmental harm is concerned. All of the chemical labels note that precautions should be used in handling of the proudct, and two indicate that the product may be harmful or fatal if absorbed through the skin. Only two, however, cautioned against dumping them directly into lakes, streams, or ponds. Some of the products containing 2,4,5-T listed no such precautions; yet the compound is now expressely banned in waterways.

Scale and corrosion inhibitors and biocides require the addition of acid or alkali to makeup water to keep the pH at an optimum level, usually a range from 5.5 to 7.5. Silt controls polymers may be used if makeup is raw water from a nearby lake or river. Lignin-tannin dispersives such as 1 to 50 ppm sodium lignosulfonate may be employed. Antifoulants such as 0.1 to 5 ppm of acrylamids, polyacrylate, polyethyleneimine, or other high molecular synethic organic polyelectrolytes may also be used.108ee

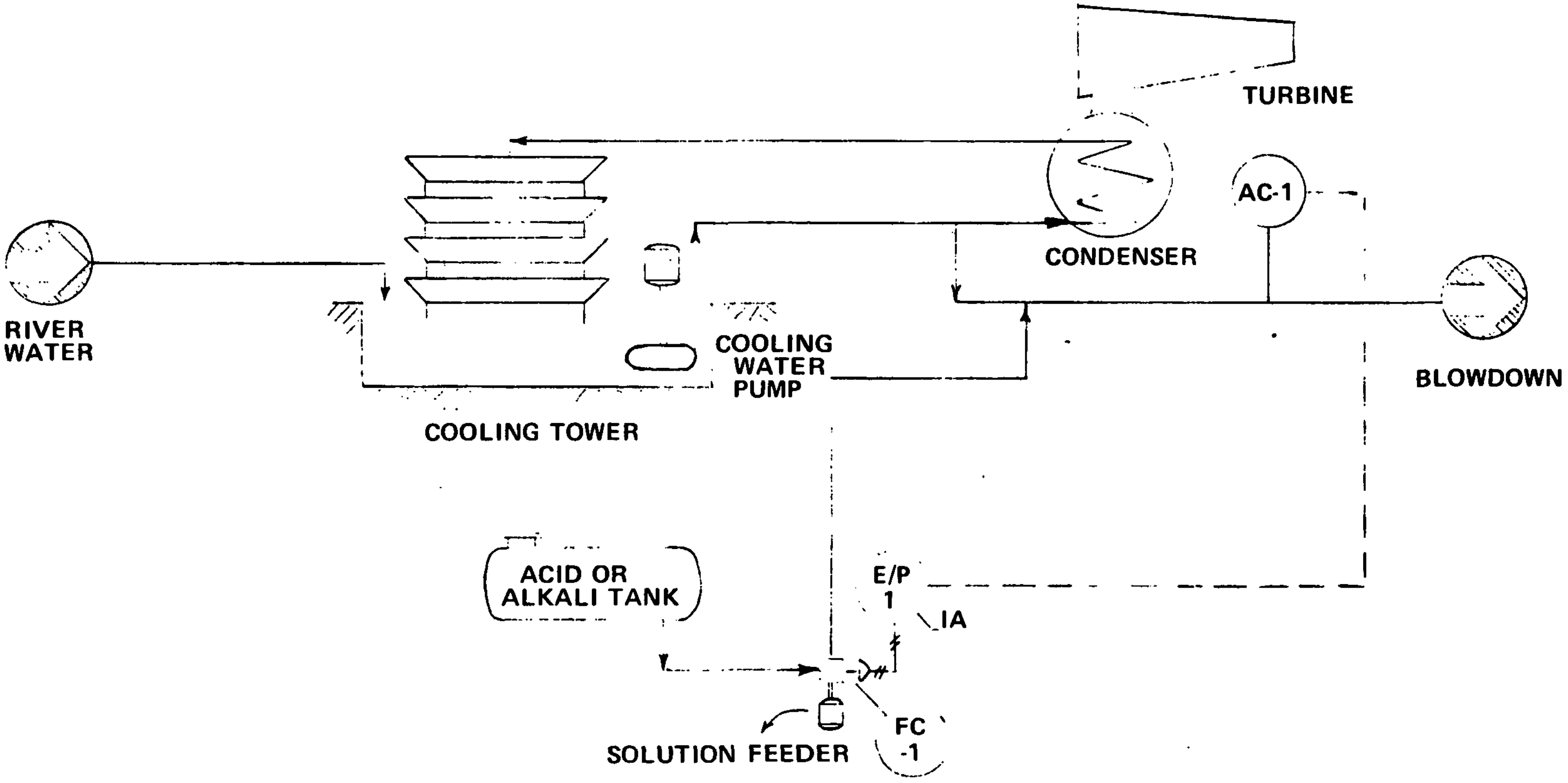
Wood deterioration includes three types of attack; chemical, biological, and physical. Chemical deterioration, which removes the lignin, is especially severe with the combined presence of high chlorine residual and high alkalinity (chlorine should be less than 1 ppm). This deterioration can be checked by maintaining the pH below 8.0. Biological attack on wood is caused by cellulolytic fungi. The application of chlorinated phenolic compounds in a controlled foam form has been found to be highly effective in promoting prolonged protection of cooling tower wood. Physical attack on wood is caused by high-temperature waters, high solids concentration, and freezing and thawing conditions.

Oxidizing biocides effectively kill the organisms, but their activity is short-lived. (Requires frequent or continuous feeding). Chemicals which are used include chlorine and calcium and sodium hydrochlorites. One method is to dose to a free available chlorine concentration of 0.3 - 0.6 ppm for a period of four hours daily. The chlorinated cyanurates and inocyanurates and other chlorinated organic materials are also used to introduce chlorine to water. Persulfate compounds, which are odorless, are also often used (potassium hydrogen persulfate). Ozone, another oxidizing biocide, is undergoing experiment for use in various systems. It is a very powerful oxidizing agent and is twice as potent as chlorine for destroying bacteria and organic matter. It also oxidizes undesirable metals such as iron and manganese. Several nonoxidizing biocides are also being used. Some of these compounds include: chlorinated phenolic compounds - chlorinated and phenylated phenols and their sodium or potassium salts; organotin - complex amine combinations; surface-active agents such as quartenary ammonium groups; organo-sulphur compounds such as dithocarbamate salts and the thiuram mono - and disulfides; rosin amine salts formed by reaction with carboxylic acids and acidic phenols such as the salts of acetic acid and pentachlorophenol; copper salts such as copper sulfate; thiocyanates such as methylene thiocyanates and bisthiocyanate; and acrolein which is highly flammable and may be toxic to warm-blooded animals.

In cooling water systems, two types of corrosion inhibitors can be used - anodic and cathodic. Chromates, orthophosphates and nitrite - based products are examples of anodic corrosion inhibitors. Polyphosphate, silicate, and metal salts which form sparingly soluble hydroxides, oxides and carbonates (such as zinc) act as cathodic inhibitors. Chromates and other heavy metals may be harmful to aquatic organisms. Phosphates can serve as a nutrient to aquatic life. Inorganic, nonchromate corrosion inhibitors consist of various combinations of polyphosphates, silicates, borates, ferrocyanides, nitrates, and metal ions such as zinc and copper (straight polyphosphate, zinc - polyphosphate, and ferro cyanide - polyphosphate). Work is being done to develop nonpolluting corrosion inhibiting components. Two such compounds are sodium and mercaptobenzothiazole and derivatives of organo-phosphorus. Dearborn Chemical Division of W. R. Grace and Company has developed a nonchromate, nonphosphate corrosion inhibitor. The synthetic-organic corrosion inhibitor which is hydrolytically stable and possibly nontoxic. This compound is designed to reduce scaling and fouling on heat transfer surfaces. It is not as effective as zinc and chromates, but is at least as effective as other comparative nonchromate and zinc polyphosphate compounds.

A film-forming sulfophosphated organic corrosion inhibitor is put out by the Tretolite Division of Petrolite Corporation. Tretolite states that it is effective in both fresh and high brine waters and is less toxic to fish and other aquatic life than metal salts such as chromate. Its toxicity compares to that of methanol, gasoline, and xylene. It is said that the inhibitor also performs well in the presence of H_2S or CO_2.

Scale deposits are prevented by controlling the hardness and alkalinity of the water system. This is normally done by feeding an acid to the water to neutralize the bicarbonate alkalinity. An acid which is widely used is sulfuric acid. Most cooling tower systems are controlled in the pH range of six to seven. This range depends on the balance between corrosion inhibition and deposit control. Organic phosphate compounds such as aminimethylenephosphonate are used in concentrations up to 3 ppm. Phosphonates and polyelectrolites are used as deposit-control agents. A possible arrangement for pH control is shown in Figure A-VII-13.



LEGEND:
AC-1: PH SENSOR & TRANSMITTER
E/P-1: ELECTROPNEUMATIC TRANSDUCER
FC-1: FLOW CONTROL VALVE
———— : FLOW PATH
– – – – : CONTROL SIGNAL (ELECTRICAL)
–//–//– : CONTROL SIGNAL (PNEUMATIC)

FIGURE A-VII-13 RECIRCULATING CONDENSER COOLING SYSTEM pH CONTROL OF BLOWDOWN

The following corrosion and scale inhibitary chemicals may be employed at the concentrations given.108ee

1.	Chromate plus zinc	5 to 30 mg/l CrO_4 1 to 15 mg/l Zn
2.	Chromate plus zinc plus phosphate	5 to 30 mg/l CrO_4 1 to 15 mg/l Zn 1 to 5 mg/l PO_4 (inorganic) 1 to 5 mg/l (organic)
3.	Zinc plus inorganic phosphate	10 to 30 mg/l PO_4 2 to 10 mg/l Zn
4.	Zinc plus organic phosphate	1 to 10 mg/l Zn 3 to 15 mg/l PO_4 (organic)
5.	Organic phosphate scale inhibitor	1 to 18 mg/l PO_4 (organic)
6.	Specific copper corrosion inhibitors	1 to 5 mg/l sodium mercaptobenzothiazole or benzotriazole

Consider the problem of trying to maintain condenser cleanliness in the situation where the discharge is permitted of the mildly concentrated and untreated tower system blowdown to a receiving stream but the plant is not permitted to discharge any inhibiting chemicals that might be used normally for scale or corrosion control. Such inhibitors might include individual or combined compounds of zinc, chromate, hexametaphosphate, phosphonate, polyol esters, etc. In essence, the tower system would have no chemical conditioning except for shock application of a biocide to control slime and algae and the use of an acid to adjust alkalinity.

This method of minimum chemical treatment involves controlling the stability index of the system water, by acid feed, to a point where it is in a slightly scaling condition plus shock chlorination. The objectives in operation is to produce a water with a slight scaling tendency thereby eliminating the basic requirement of a corrosion inhibitor. Nor is the scaling tendency to be viewed with alarm if the tower system is equipped with on-line condenser tube cleaning equipment such as that supplied by Amertap or M.A.N. Mild descaling also can be accomplished by depression of the pH in the tower system to 5.0 for about 8 hours once weekly. Mild descaling does not increase the overall rate of corrosion. In this regard the installation of corrosion probes in the system may be required for monitoring corrosion rates either periodically or continuously.

Shock chlorination of the condenser cooling water for about 20 minutes daily, or one complete cycle, will be adequate to control the growth of bacterial slimes and algae under the usual conditions. If not, a second application some 8 hours later would be indicated. The free available chlorine in the water returning to the tower must be limited to 1.0 to 1.5 mg/l in order not to delignify the wood components of the tower. If the cooling tower is all wood the components should have been specified for chemical pretreatment to prevent fungal attack and to withstand any excess alkalinity in the cooling water.

The manufacturers of on-line condenser cleaning equipment suggest that chlorine is not needed when their equipment is used; the tubes supposedly are kept free of bacterial growth. Chlorine, or an equivalent biocide, however, is certainly needed to prevent excessive growths on the tower deck and tower fill. If the growths are allowed to proliferage on the decks the distribution orifices may become plugged and cause flooding. Excessive growths on the fill decrease tower efficiency.

Tables A-VII-6 and A-VII-7 shows the average operational values for a cooling tower system without any chemical conditioning other than acid for the control of alkalinity; and with complete chemical conditioning. The condenser is provided with on-line mechanical cleaning equipment.

Chemical Cleaning of Condenser Tubes During Scheduled Outages

Condensers are by far the largest heat exchanger in the condensate-feedwater cycle. They contain from 5,000 to 50,000 tubes, 7/8 or 1" O.D. by 20 to 60 feet long. Tube materials may be stainless steel or brass alloys such as admiralty brass, aluminum brass, aluminum bronze, arsenical copper, 90/10 or 70/30 cupro-nickel. The tubes may be contained in one housing or shell or because of size may be arranged in from 2 to 6 shells for very large units. Each shell may be considered a condenser in itself.

In function the condenser serves to re-liquefy the steam which exhausts from the last row of blades of the turbine and flows around the tubes. Cooling water flows through the tubes extracting heat from the tube walls which interface with the steam. The overall cleanliness of the tube

Table A-VII-6

NO CHEMICAL CONDITIONING OF COOLING TOWER SYSTEM EXCEPT FOR ALKALINITY CONTROL, BUT USING ON-LINE MECHANICAL CLEANING CONDENSER TUBES[387]

Untreated River Makeup to Tower	mg/l	Cooling Tower System	mg/l
Ca as $CaCO_3$	100	Ca as $CaCO_3$	500
Mg as $CaCO_3$	64	Mg as $CaCO_3$	320
HCO_3 as $CaCO_3$	148	HCO_3 as $CaCO_3$	136
Cl as Cl^-	4	Cl as Cl^-	18
SO_4 as SO_4	10	SO_4 as SO_4	645
SiO_2 as SiO_2	6	SiO_2 as SiO_2	27
pH	7.5	pH	8.0

Table A-VII-7

COMPLETE CHEMICAL CONDITIONING OF COOLING TOWER SYSTEM AT "ZERO" DISCHARGE WITH SIDESTREAM TREATMENT OF TOWER WATER AND ON-LINE MECHANICAL CLEANING CONDENSER TUBES[387]

Untreated River Makeup to Tower	mg/l	Cooling Tower System	mg/l
Ca as $CaCO_3$	230	Ca as $CaCO_3$	260
Mg as $CaCO_3$	172	Mg as $CaCO_3$	175
HCO_3 as $CaCO_3$	263	HCO_3 as $CaCO_3$	300
Na as Na	24	Na as Na	7,740
Cl as Cl^-	12	Cl as Cl^-	1,030
SO_4 as SO_4	174	SO_4 as SO_4	14,800
SiO_2 as SiO_2	20	SiO_2 as SiO_2	20
pH	7.5	Organic PO_4	25
		pH	8.5

surfaces is critically important to the efficiency of the condenser, to the degree of vacuum placed in the turbine, and hence to the efficiency of the plant.

Chemical cleaning of condenser tubes is usually performed during a scheduled outage of the unit, unless the fouling has reached a magnitude that warrants a separate outage beforehand. The chemical cleaning is relatively simple, using either the acid foaming technique or the soak method. The condenser can be cleaned within 12 hours if all preliminary operations have been organized. Of the two methods, soaking has proved to be more thorough than foaming.

The foaming method consists of a foam generator, with a mixing tank to produce an acid foam that is then pumped to specified sections of the water box. The foamed mixture flows by gravity through the condenser tubes and then to waste. Since there is no pressure involved, the top rows of tubes, or a condenser tube that is partially blocked, will receive hardly any foam and remain uncleaned.. It is important before cleaning that all of the tubes should be inspected and any potential blockage removed. It is not uncommon to find numerous tubes partially blocked with pieces of wood, particularly after icing conditions cause damage to tower fill. Wind blown grass and similar debris will also cause blockage. The efficiency of foam cleaning in a relatively short contact time is attributed to the strength of acid used, in this case about 15 percent compared to the usual 5 to 7 percent acid in soaking. Either inhibited sulfuric acid or mixed organic acids may be used when foaming austenitic stainless steel tubes. At the strength of 15 percent it would not be prudent to use hydrochloric in contact with this steel. Neutralization with an alkali is not needed following the acid foam or soak cleaning. The usual practice is to start the circulating pumps and flush the condenser for about 30 minutes to remove any residual acid. Then, the water boxes can be reopened for inspection.

Chemical cleaning by the soak method is merely filling the water boxes to the top rows of condenser tubes with inhibited acid plus 0.5 percent ammonium bifluoride at ambient temperature. The acid strenght is 5.0 to 7.5 percent. Circulation is used when practical by repumping the acid solution from the condenser to the acid delivery tank truck and then back to the condenser. Although the acid recirculation rate is relatively low, the reaction rate is increased by circulating fresh acid over the deposition. The choice of acid for the soak method is generally hydrochloric because of its rapid reaction with carbonate scale without forming an insoluble by-product. Other deposits also are more easily solubilized. The addition of ammonium bifluoride intensifies the solubility of silicate and iron deposition. Sulfuric acid also will react with calcium carbonate deposition, but produces an insoluble calcium sulfate precipitate that may settle out and adhere to the tubes in quiescent soaking. Therefore, the choice of acid is usually hydrochloric even if the condenser tube material is austenitic stainless steel. Corrosion tests show essentially the same rates for stainless with sulfuric or hydrochloric under soaking conditions; neither stress nor crevice corrosion has occured with hydrochloric as used at ambient temperature.

Mechanical Cleaning of Condenser Tubes

On-Line Mechanical Cleaning

Equipment for on-line mechanical cleaning of condenser tubes is manufactured primarily by the Amertap Corporation and by the M.A.N. Corporation of West Germany. By far, most of the installations at electric generating plants in the United States have been supplied by Amertap. In principle, each of the two systems has the same objectives; that is, to maintain condenser tube cleanliness continuously while in operation by mechanical means instead of chemical.

The basic principle of the Amertap system is to circulate oversize sponge rubber balls through the condenser tubes with the cooling water. These balls, after the original charge, are injected into the inlet pipe, collected at the discharge piping in a basket arrangement and then repumped continually to the inlet. The number of balls in the system is approximately 10 percent of the number of tubes in the condenser. Amertap estimates that each tube receives a ball on the average of every 5 minutes with a normal circulation time per ball of 20 to 30 seconds. However, any tube that becomes partially blocked at the entrance or within its length will not become unblocked by the ball. The effectiveness of the sponge balls is for removing soft chemical precipitates or bacterial slimes before then can become adherent. Because the balls are porous a certain amount of water flows through the balls and loosens the accumulated deposits retained on the balls. The balls are also furnished with an abrasive band, to be used only where older deposition needs to be removed by the scouring action of the abrasive. A schematic arrangement of the Amertap system is shown is Figure A-VII-14.

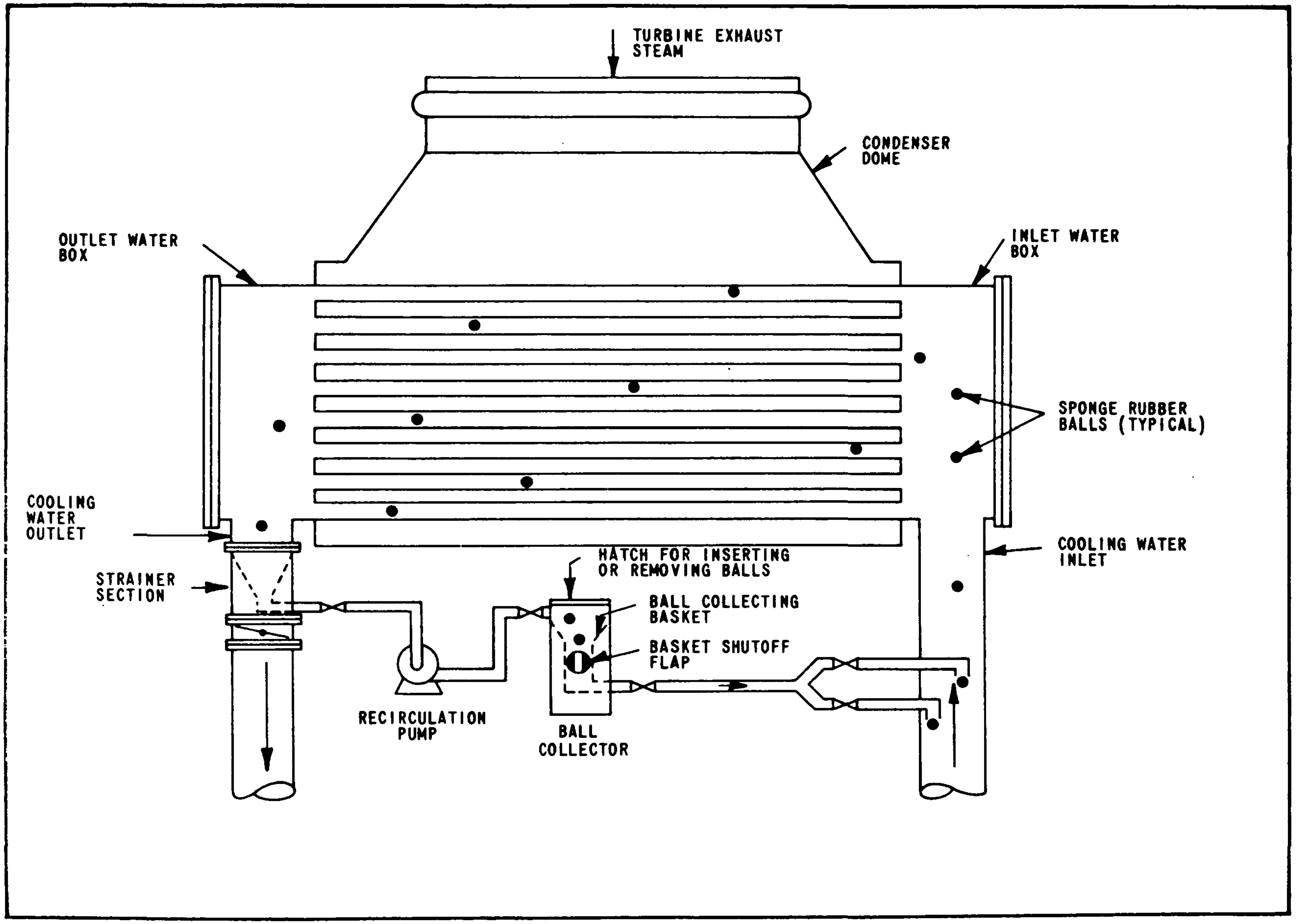


Figure A-VII-14
SCHEMATIC ARRANGEMENT AMERTAP TUBE CLEANING SYSTEM

The M.A.N. system for on-line mechanical cleaning uses a brush device about 50 mm long sized to pass through the condenser tubes intermittently. The M.A.N. system has to be incorporated in the original design of a condenser in order to provide additional tube length for attachment of a plastic cage on each end of each tube to hold the brush device. The plastic cage length is about 75 mm. To attach the plastic cage to the tube ends, the tubes have to extend 10 mm beyond the tube sheet. Therefore, inlet tube ends have to be straight instead of flared as would be the usual practice to avoid inlet end erosion. The tube sheets do not have to be machined for flaring with the M.A.N. system. Provisions for reversing the flow of condenser cooling water have to be incorporated in the original design of the auxiliary equipment. To clean the tubes the cooling water flow is reversed, which forces the brushes through the tubes to the plastic cage at the opposite end. Then the cooling water flow is returned to the normal direction, the brushes would be forced to their normal resting position in the cages at the outlet ends of the tubes. Recycling can be set up automatically for whatever frequency of backwash is desired. Twice daily is normal. The schematic arrangement of the reverse flow piping for the M.A.N. system is shown in Figure A-VII-15.

A current Edison Electric Institute survey conducted among member companies comparing chlorination versus mechanical cleaning of condenser tubes may be indicative of the degree to which mechanical devices for maintaining tube cleanliness have been successful and the degree to which the supplemental use of chlorine is required. As of May 24, 1974, fourteen (14) respondents had supplied answers covering two types of in-service mechanical cleaning installations on the condenser cooling water systems for 54 powerplant units.

1. Three of the reported units have had the M.A.N. system, which is the system that uses bristle brushes; and the other 51 units had or have the Amertap System, which is the system that uses sponge balls.

2. None of the three M.A.N. systems is still in service. One of these systems tended to become fouled by leaves and twigs - and even a few fish. On another, severe grooving of tubes was found.

3. Of the 51 Amertap units reported, 46 units are still in service.

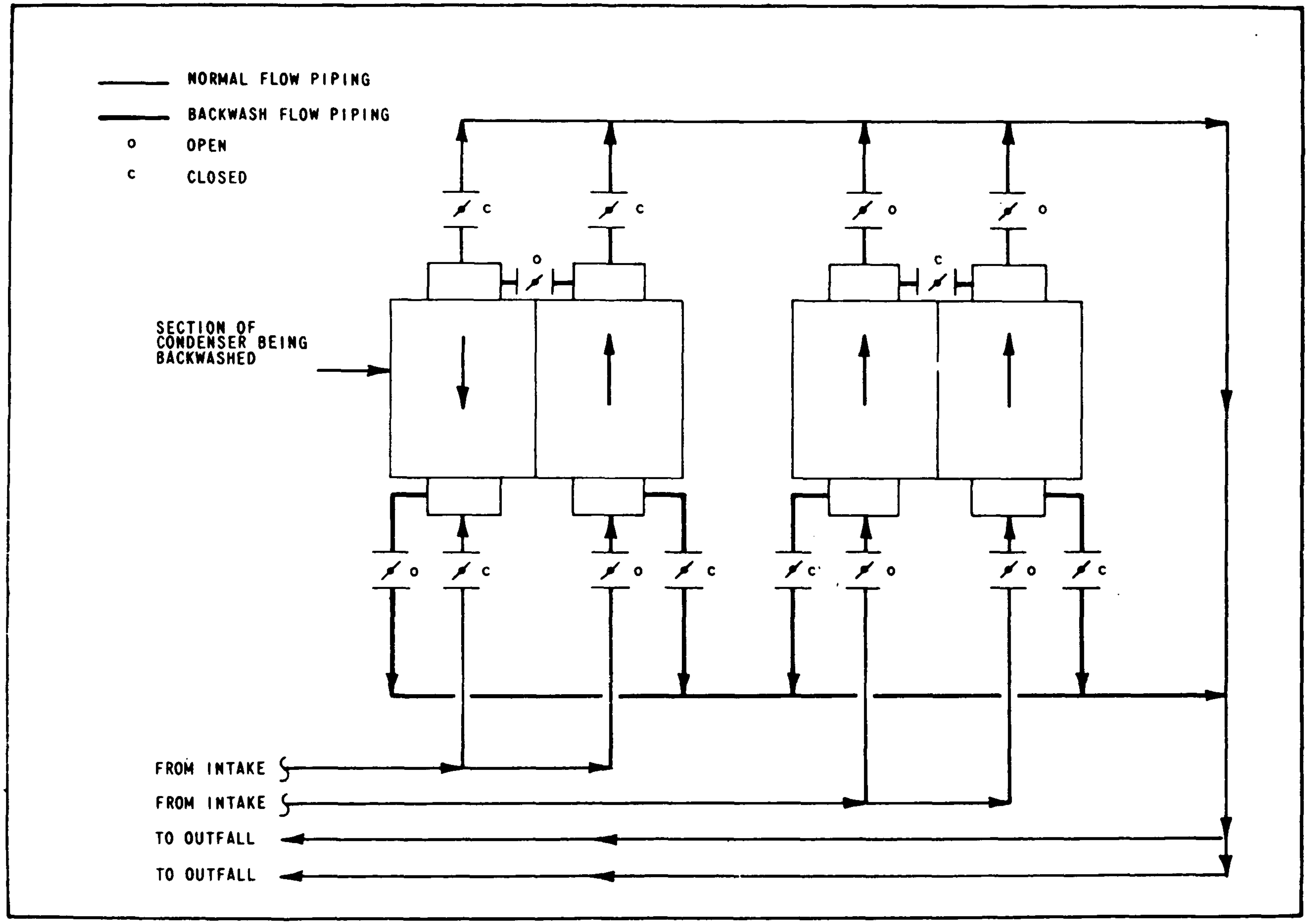


Figure A-VII-15 Reverse Flow Piping

4. Of the 46 Amertap units now in service 25 also use chlorination, and 21 do not use chlorine.

5. For the 21 Amertap Systems in service without chlorination the cooling water systems are:

   Acid mine-water, once-through, 9 systems
   Closed cycle cooling towers or ponds, 6 systems
   Brackish water once-through, 2 systems
   Sea Water once-through, 2 systems
   Fresh water once-through, 2 systems

6. Of the 51 Amertap units reported by respondents, 7 reported that they thought good heat transfer could be maintained without chlorination and 6 reported they think chlorination is necessary.

7. For the 46 Amertap units now in service, it was reported that the primary purpose of the mechnical cleaning system was for the control of:

   a. sediment, sludge or scale, for 41 units
   b. slime for 5 units

8. Of the five (5) systems that are reported to be in service for the purpose cf controlling slime, only one (1) uses once-through cooling with fresh water, and the other four (4) use once-through cooling with brackish water.

9. Of these five(5) systems that are reported to be in service for the purpose of controlling slime, two (2) also use chlorination, and one of the others has had only limited operation.

Mechanical Cleaning During Scheduled Outages

Manual mechanical cleaning of condenser tubes is accomplished with short bristle brushes, rubber balls, or scraper devices shot through the tubes individually by water pressure or combined with air pressure. High pressure water lancing alone has been used. The procees is laborious, time-comsuming, extremely monotonous, and often uneconomical.

If the deposition in the tubes is loose, or in thin curls, after the tubes become dry, the brushes or balls will do a fairly satisfactory job. Brushes or balls are used by plants that need to clean tubes at repeated intervals to maintain cleanliness. When the desposition is adherent the short metal scraper-type devices will be more effective; they are shot through the tubes with water and air pressure. The overall shooting time will be longer with scrapers than with brushes. Regardless of the device used it is a good idea to keep an inventory of the number before and after cleaning. The mechanical cleaning time will range from 50 tubes to 300 tubes per man-hour depending on whether scrapers or brushes are used and on the attitude of the crew.

As a rule, mechanical cleaning is practiced at small generating plants where the labor may be readily available and economical. It may also be a plant where quality control for the cooling system is continuously disregarded by the operating personnel, requiring that the condenser tubes be mechanically cleaned fairly regularly. In this case, plant labor would be used instead of using outside services for chemical cleaning which would require management appropriation of capital.

Economics of Condenser Cleanliness

Comparative capital costs of the Amertap system and the M.A.N. system are shown in Table A-VII-8 As noted on the table, the costs shown are additional costs to those that would be required for conventional chemical conditioning. The costs are for a 675 Mw generating unit to be installed in 1979 which will be equipped with an open recirculating cooling system using mechanical draft cooling towers.

Table A-VII-9 shows comparative costs of operation and total annual costs for the same 675 Mw generating unit. The demand and energy costs reflect increased circulating water pumping costs for the mechanical systems due to friction of the plastic cages of the M.A.N. system, and of the strainers of the Amertap system. For the Amertap system they also reflect the cost of operating the small pumps that recirculate the balls. The annual fixed charge rate is assumed to be 15.0 percent.

As tube cleanliness decreases, the condenser pressure increases which causes the turbine heat rate to increase and generating cpability to decrease. Figure A-VII-16 shows tube cleanliness factor plotted against the annual cost of increased fuel and reduced capability for the same 675 Mw unit. The unit is assumed to operate at an annual capacity factor of 86.5 percent, fuel is evaluated at a price of 45 cents per million Btu, and generating capacity is evaluated at an annual cost of $20.80 per kw. The costs plotted in Figure A-VII-16 are additional costs as the cleanliness

Table A-VII-8

COMPARATIVE CAPITAL COSTS* OF CONDENSER CLEANING SYSTEMS 387

	Amertap System $	M.A.N. System $
M.A.N System, Baskets and Brushes	–	72,000
Amertap System	160,000	
Tubing	Base	1,000
Tube Sheet Machining	Base	(37,000)
Backwash Piping and Valves	Base	107,000
Miscellaneous Piping and Valves	10,000	Base
Controls	35,000	6,000
Mechanical Construction	34,000	12,000
Electrical Construction	22,000	3,000
General Construction	8,000	Base
Subtotal	269,000	164,000
Indirect Costs at 16 Percent	43,000	26,000
Comparative Capital Costs*	312,000	190,000

*Costs shown are increases or (decreases) from capital costs of a conventional chemical cleaning system. Costs are for a 675 MW generating unit to be installed in 1979, operating with an open recirculating cooling system using mechanical draft cooling towers.

Table A-VII-9

COMPARATIVE ANNUAL COSTS* 387

Annual Costs of Operation*	Conventional Chemical Treatment $	Amertap System $	M.A.N. System $
Manual Brush Cleaning of Tubes	5,000	–	–
Chemicals	23,000	20,000	20,000
M.A.N. System Brushes	–	–	16,000
Amertap Balls	–	19,000	–
Demand and Energy Costs	Base	6,500	12,100
Comparative Costs of Operation	28,000	45,500	48,100
Total Annual Costs*			
Fixed Charges	Base	46,800	28,500
Costs of Operation	28,000	45,500	48,100
Comparative Total Annual Costs	28,000	92,300	76,600
Differential Total Annual Costs	Base	64,300	48,600

*Costs are for a 675 MW generating unit to be installed in 1979, operating with an open recirculating cooling system using mechanical draft cooling towers. Annual fixed charge rate is 15.0 percent.

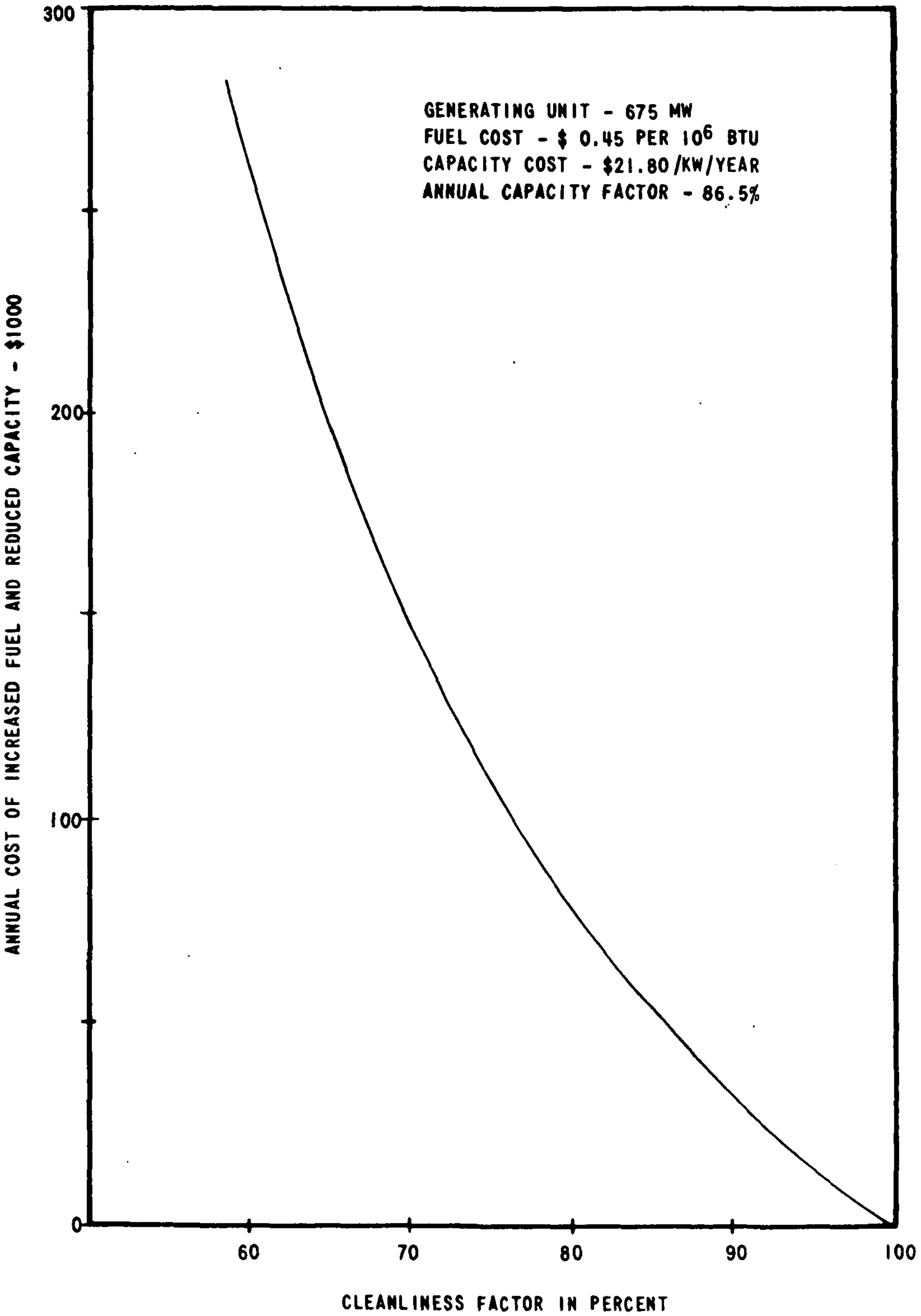


Figure A-VII-16

TUBE CLEANLINESS VERSUS COST OF REDUCED GENERATING EFFICIENCY [387] factor decreases from 100 percent (which reflects the cleanliness of new clean tubes).

Costs of operation shown in Table A-VII-9 are based on all cleaning systems maintaining the same degree of cleanliness. It is expected that the Amertap system can maintain tube cleanliness at about 95 percent, if placed in service when the condenser tubes are new, and that the M.A.N. system can maintain tube cleanliness at about 90 percent. The reason that the M.A.N. system would not be able to maintain the cleanliness level as high as the Amertap system is that the M.A.N. system operates intermittently, while the Amertap system is a continuous cleaning system.

The comparative annual costs shown in Table A-VII-9 and on Figure A-VII-16 can be used to determine whether or not a mechanical cleaning system such as the M.A.N. system or the Amertap system can be economically justified. For the 675 Mw unit, neither a M.A.N. system with a cleanliness factor of 90 percent nor an Amertap system with a cleanilness of 95 percent could be justified unless the cleanliness factor with conventional chemical conditioning is less than 80 percent. This conclusion applies only to the case studied since it is dependent on such parameters as generator size, capacity factor, and the fuel cost. However, it serves as a general indication of the amount of improvement in cleanliness factor that must be achieved in order to justify an on-line mechanial cleaning system.

Design for Corrosion Protection

The use of corrosion resistant materials is standard practice in the electric utility industry. Unlike most other industries, power plants are built for service lives of thirty years or more. Thus, corrosion prevention is a necessary consideration in power plant cooling systems. Although corrosion resistant materials are more costly, their use is justified by less maintenance, improved heat transfer, and reduced water treatment costs. Corrosion and scale inhibiting chemical usage can be minimized in large cooling water systems through the proper selection of construction materials and protective coatings. In fact, there are a few power plants where the existence of corrosion resistant materials plus the use of on-line condenser tube cleaning equipment has eliminated the need for chlorine and other biocides, thus allowing operation without any chemical treatment.

In addition, corrosion resistant materials generally help prevent water pollution. By minimizing corrosion and scale inhibiting chemical usage, the amounts of harmful materials such as zinc and chromate discharged into lakes and streams are reduced. Corrosion products in blowdown streams can also be maintained at low levels.

Corrosion Resistant Materials in Condensers

The use of corrosion resistant materials in steam condenser tubes is standard practice. A wide variety of materials are in use or are available including admiralty, 304 and 316 stainless steel and copper-nickel alloys.

Cold water boxes are normally made of carbon steel. Occasionally, phenolic or epoxy coatings are applied.

Corrosion Resistant Materials in Cooling Towers

Although redwood or Douglas fir are still the normal structural elements used in mechanical draft cooling towers, concrete towers are now being built. All the hyperbolic natural draft cooling towers built in the United States to date have been of concrete construction. Concrete towers should last longer, are structurally superior to wood and can save utility companies on fire insurance preminums. A cooling tower manufacturing recently mentioned that a client could save $100,000/year on insurance premiums by using concrete induced-draft cooling towers instead of wood.

Type 2 concrete is normally used for cooling towers, but where waters containing 1,000 ppm or more of sulfate ion (SO_4^{--}) are encountered such as in the West and Southwest, Type 5 must be specified.

The use of wood in the internals of large cooling towers is also diminishing. Plastics such as polyvinyl chloride (PVC) are now being used for splash-type tower fill, drift eliminators, and fill hangers. Film-type fill is normally made from asbestos concrete board (ACB). Air louvers and some drift eliminators are also made of ACB. When ACB is used in a tower, it is important to maintain cooling system pH at more than 6.0 to avoid deterioration.

Hardware used in cooling tower construction is normally stainless steel, although hot dipped galvanized steel, naval brass, copper alloys and silicon-bronze can also be used.

Stacks in mechanical draft towers are generally made from fiberglass reinforced plastic (FRP).

Redwood stave piping is being used less frequently since redwood is becoming more scarce. Risers and headers, which are large pipes located at the cooling towers, are made of concrete or redwood staves, and less frequently of vinyl painted carbon steel. Where brackish or salt water is used for tower makeup, 316 stainless steel and coated carbon steel are commonly specified for piping systems.

Concrete and stainless steel cost 2-3 times more than carbon steel. Cost differences between stainless steel and prestressed reinforced concrete will depend on differences in material grade, freight charges and installation costs.

Most power companies do not make detailed cost comparisons between piping materials, but one Ohio utility determined that for a new power plant, concrete recirculation lines would cost about $300,000 more than coated carbon steel.

Spray cooling apparatus is normally constructed with 304 or 316 stainless steel. Cathodic protection devices have been installed cn some floating spray aerator-coolers.

Resistant Pretreatments and Coatings

Redwood and Douglas fir construction materials used in mechanical draft cooling towers are always pressure treated with either acid copper chromate or chromated copper arsenate to prevent fungus attack. Tower suppliers have indicated that this pretreatment is effective and that leaching of the treatment chemical does not occur after the initial few weeks of tower operation.

Since chemical pretreatment of cooling tower lumber is a necessary process, its costs has not been separated from the total purchased cost of tower systems.

Carbon steel pipe and hardware are sometimes coated with epoxy, phenolic, or vinyl paints to reduce corrosion rates. Steel piping is occassionally given a coal tar bitumastic coating on the inside to prevent corrosion. Bitumastic coatings may also be applied to the outside of pipes to prevent leakage and corrosions. These coatings normally cost $20 - $40/ft of pipe length.

Saltwater Cooling Towers

Reference 390, a state of the art report on saltwater cooling towers, addresses, as a major topic, design consideration related to the corrosive action of salt water on cooling system equipment. The incremental deterioration due to corrosion effects of salt water being used in a cooling tower is of the same nature as those expected elsewhere in the plant where this water is being circulated. With well-designed and constructed components where coatings, lubricants and when possible inert materials are used, most of the problem associated with the use of salt water can be reduced to make the average life the components equivalent to those exposed to fresh water.

Table A-VII-10 gives recommended construction materials for cooling towers operating with salt water. Chemicals added to reduce chemical and biological attack in saltwater cooling towers include the following: sulfuric acid, chromate, zinc compounds, organic non-chromates including polyphosphates, silicates, ferrocyanides, nitrates, and metal ions (e.g., straight polyphosphates, zinc-polyphosphates, ferrocyanide-polyphosphates, zinc-ferrocyanide-polyphosphates), organics (starch derivations, lignosulfonates, tannins, glucosates, glyceride derivations and many proprietary formulations), chlorine and bromine.

Reference 390 lists 20 saltwater cooling towers in operation as of February, 1973, and 4 proposed towers. Of the 15 towers associated with electric generating station 10 are mechanical draft, 4 are natural draft, and 2 are wet-dry mechanical draft. Circulating water flow rates for the 15 towers range from 4,900 gpm to 578,000 gpm per tower.

Cooling Tower Blowdown Treatment

A system for the chemical treatment of residual chlorine in cooling tower blowdown is currently being installed in a nuclear plant employing cooling towers, which is currently under construction. Whenever residual chlorine is present in the combined wastes flowing from the discharge channel, sodium bisulfite will be added in the last chamber of the dilution structure in sufficient quantity to react completely with the chlorine. The addition of bisulfite will be controlled automatically, using a chlorine analyzer in the discharge stream with a proposed sensitivity of about 0.01 ppm residual chlorine.

Specific methods exist for treating other individual contaminants that may occur in blowdown wastes. Table A-VII-11 lists typical levels of concentration of corrosion inhibitors used in recirculating cooling water systems, with these same concentrations existing in the blowdown from these systems.

Table A-VII-10

RECOMMENDED CONSTRUCTION MATERIALS FOR COOLING TOWERS OPERATING WITH SALT WATER

Reference 390

Component	Asbestos Cement	Concrete No. 2 or 5*	Coating Paint or Epoxy	Plastics (including reinforced fiberglass and PVC)	Stainless Steel	Silicon Bronze	Pressure-Treated Wood
Structure framework	x	x		x			x**
Water distribution system	x			x			
Fill	x			x			x**
Drift eliminators	x			x			x**
Louvers	x			x			
Fan stack				x			x**
Fans				x			
Gear housing			x		x		
Drive shaft					x		
Coupling					x		
Motor and gear support			x		x		
Bolting for mechanical support					x		
Joint connectors					x	x	
Anchor castings						x	
Bolts, nuts, washers & nails					x	x	

---

* Used by cooling tower manufacturers

**Used successfully when tower is in continuous operation.

Table A-VII-11

Waste Disposal Characteristics of Typical Cooling Tower Inhibitor Systems

Inhibitor System	Concentration in recirculating water
Chromate only	200-500 as CrO_4
Zinc	8-35 as Zn
Chromate	17-65 as CrO_4
Chromate	10-15 as CrO_4
Phosphate	30-45 as PO_4
Zinc	8-35 as Zn
Phosphate	15-60 as PO_4
Zinc	8-35 as Zn
Phosphate	15-60 as PO_4
Phosphate	15-60 as PO_4
Organic	3-10 as organic
Organic only	100-200 as organic 10 est. as BOD 100 est. as COD 50 est. as CCl_4 extract 5 est. as MBAS
Organic Biocide	30 as chlorophenol 5 as sulfone 1 as thiocyanate

There are four methods which can be used to treat the blowdown wastes containing chromate as the only inhibitor. One basic method that has worked in the past and has been proven effective is called the reduction method. This process consists of adjusting the pH of the blowdown water containing the chromium to approximately 2 with the addition of acid, usually sulfuric acid, and then the addition of a reducing agent, either sulfur dioxide or sodium metabisulfite, which releases sulfur dioxide into the solution to reduce the hexavalent chromium to the trivalent state. Then the addition of caustic or lime to raise the pH to approximately 8.5 and form insoluble chromic hydroxide precipitate. A treatment system using the reduction method is shown in Figure A-VII-17. The treated water from this system is anticipated to contain less than 0.05 ppm of chromium. Ion exchange methods have also been reported for chromate recovery from blowdown wastes.[433-436] These methods require a prefiltration step to remove suspended solids from the blowdown wastes and also require a close control on the inlet pH and salt concentration for maximum recovery. The advantage of the ion exchange methods is that the recovered chromate can be reused. Another method for chromate removal is the ANDCO proprietary process. This patented process is an electrochemical method (Figure A-VII-18) and is claimed to reduce chromate concentration to less than 0.05 ppm. Finally, a vapor-compression evaporation system is also commercially available to recover and reuse water from blowdown wastes. The concentrated brine from this system can be sent to a spray-dryer for the final salt recovery.

All the methods mentioned above are also applicable for zinc removal from blowdown wastes. Thus it is possible to coprecipitate zinc as an insoluble hydroxide by chemical precipitation.

Similarly, it is possible to use an acid regenerated zinc cation exchange process so effect a reduction in volume so that the concentrated solution can be "hauled away or rendered harmless by precipitation"[437]. The ANDCO process is also claimed to reduce zinc from blowdown wastes.

Phosphate can also be removed by chemical precipitation. Addition of alum is required for higher efficiency. An adsorption process that apparently is applicable to crudely filtered or undiltered blowdown containing phosphate, only, has been reported in the literature.

Depending upon the make-up water quality and the plant specifics, it is possible to investigate various

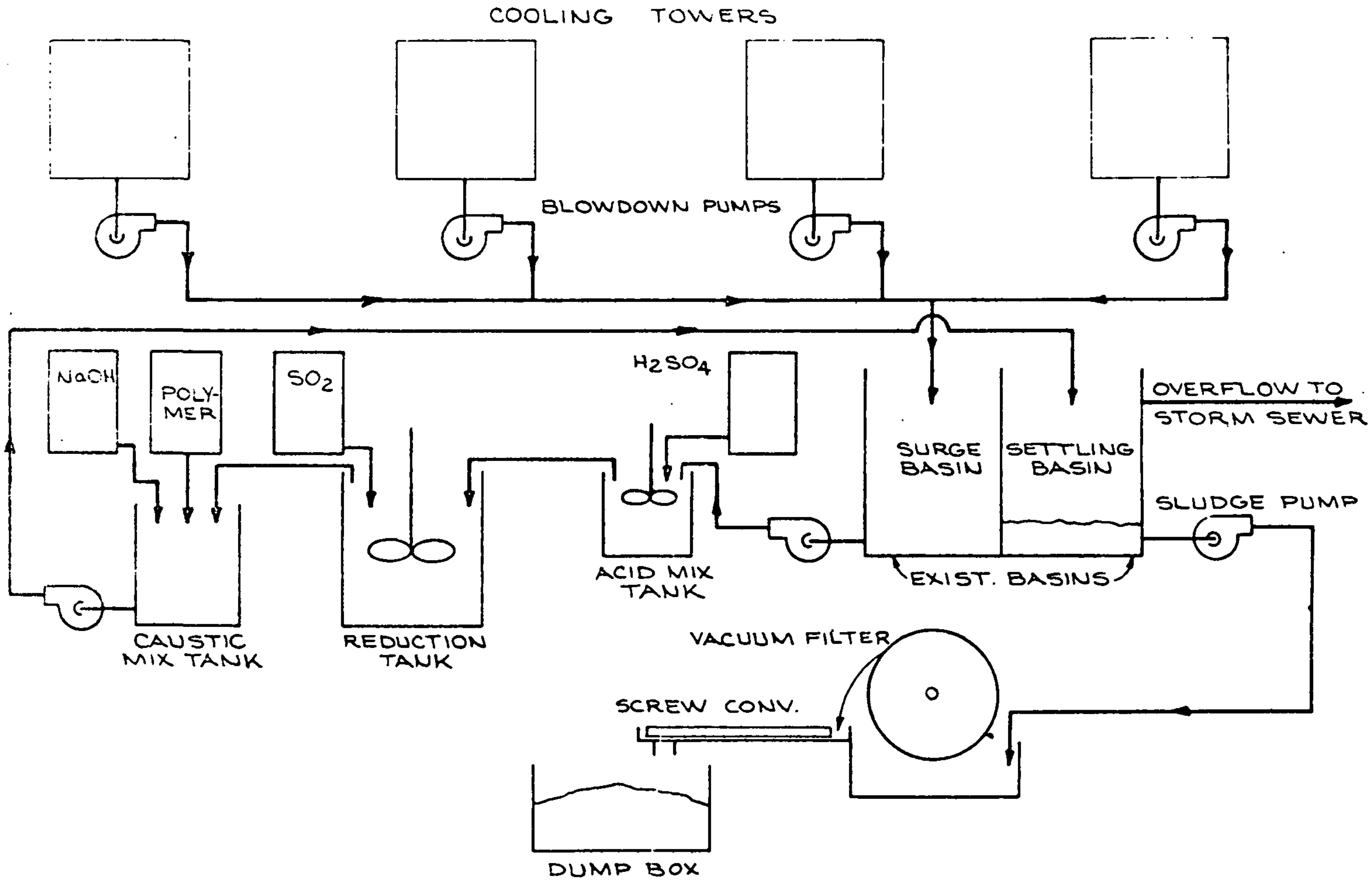


Figure A-VII-17 Cooling Tower Blowdown Chromate Reduction System

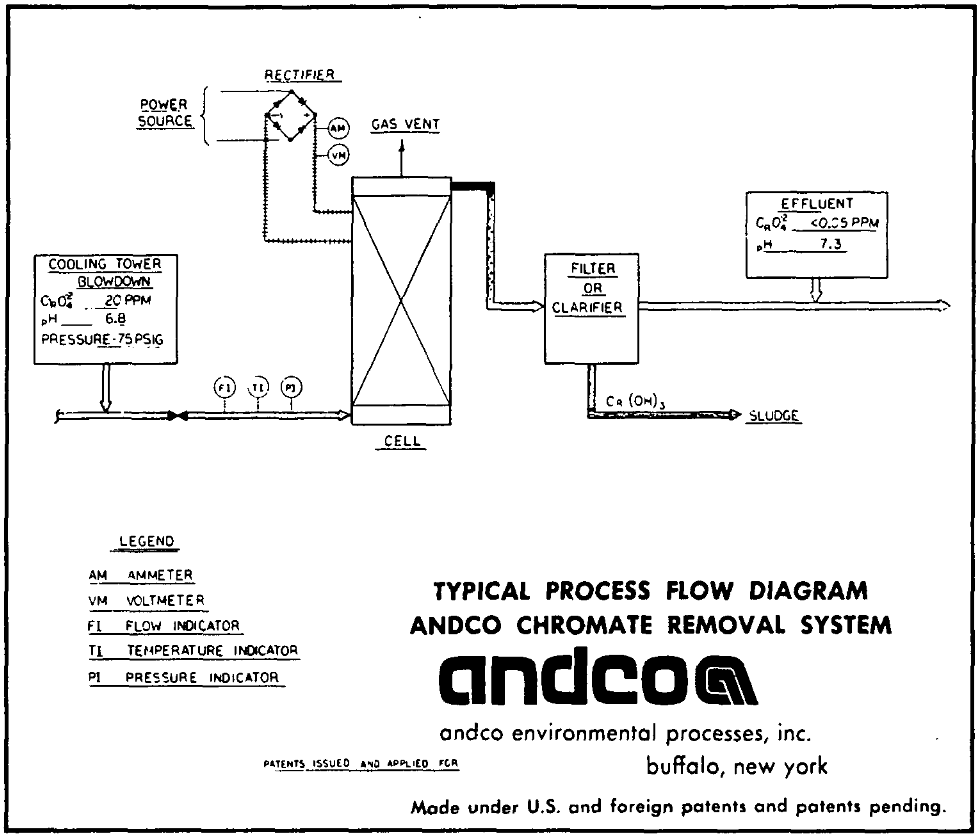


Figure A-VII-18

Typical Process Flow Diagram
Chromate Removal System 453

alternatives methods to select the most practical and economic method to minimize blowdown flow. The Southern California Edison Company has achieved a 31% reduction in the cooling tower blowdown at the Etiwanda generating station by modifying the treatment technique.[440] Similarly, the company has included facilities in a new plant design for cold lime-soda as makeup softening to achieve zero blowdown operation (Figure A-VII-19). This will reduce total pondage requirements from 240 acres to 34 acres. (Pondage is required for softening sludge disposal, other plant liquid wastes and for periods of softening equipment outages when blowdown from cooling towers will be necessary).

Reference 445 analyzed four basic approaches for the concentration of cooling tower blowdown to a dry or almost dry, solid as follows:

> Evaporation, in a conventional multi-effect evaporator-crystallizer, to a slurry from which mother liquor is finally removed by a centrifuge, yielding damp crystals.
>
> Preliminary distillation in a multi-stage flash (MSF) plant, followed by an evaporator-crystallizer somewhat smaller than in the first approach.
>
> Passage of the tower blowdown through a cation exhanger, plus reverse osmosis (R.O.), followed by an evaporator-crystallizer of larger size than in the second approach.
>
> Identical with the third approach but with an MSF plant after the R.O. unit, resulting in a small evaporator-crystallizer of only one effect.

In each of the cases involving MSF, two types of MSF plants were studied: (1) a high-capital cost plant, very efficient in energy utilization, and (2) a less efficient but less costly plant.

The various combinations of processes are shown in Figure A-VII-20.

Water Treatment Wastes

Clarification, Softening and Filtration

The waste streams from these operations are sludges, whose composition will vary depending on the raw water quality and the method of treatment. Sludges from plain sedimentation are essentially silty in character. If alum is used as a

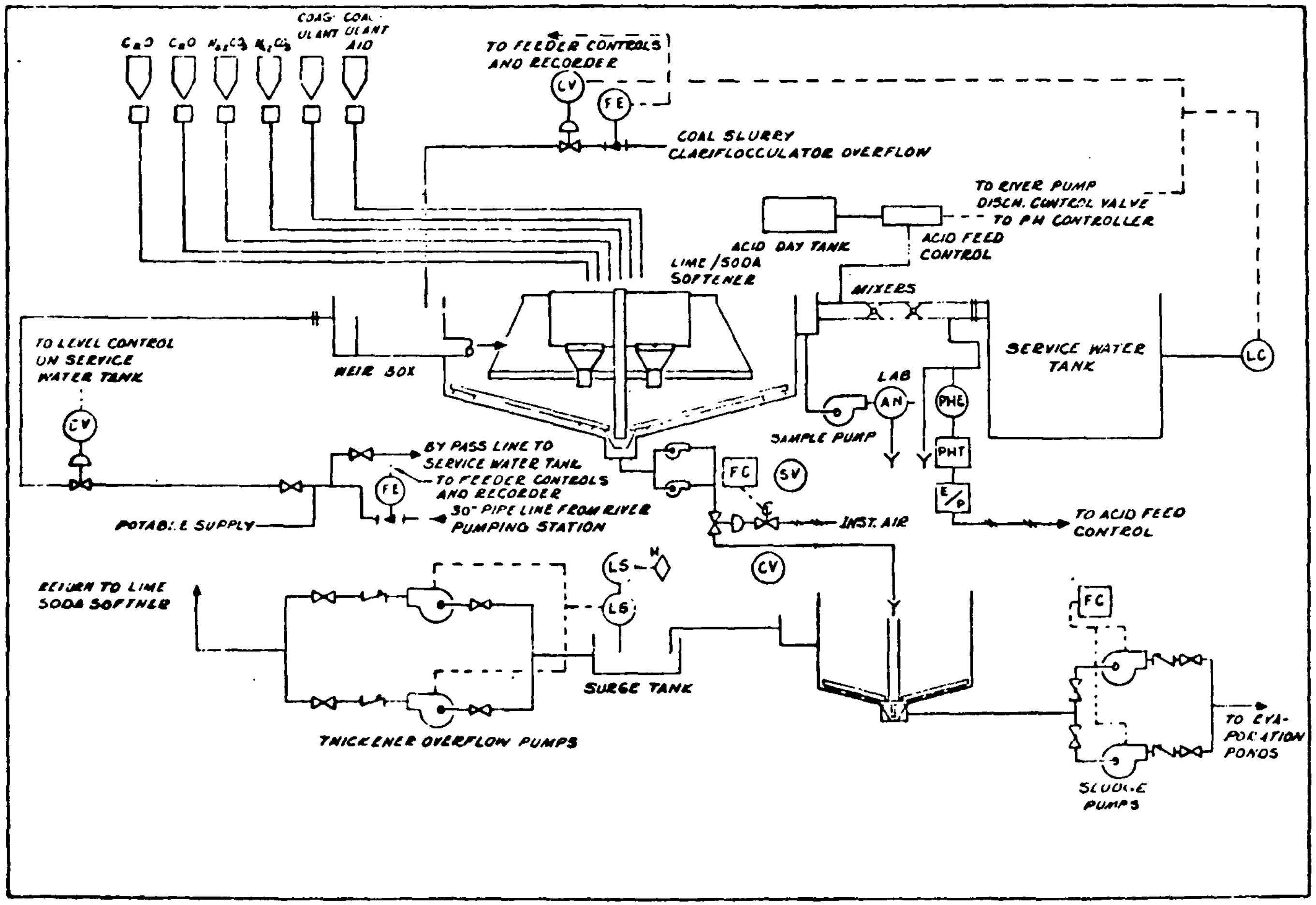


Figure A-VII-19 Flow diagram of the primary water treatment plant, Mohave generating stations.

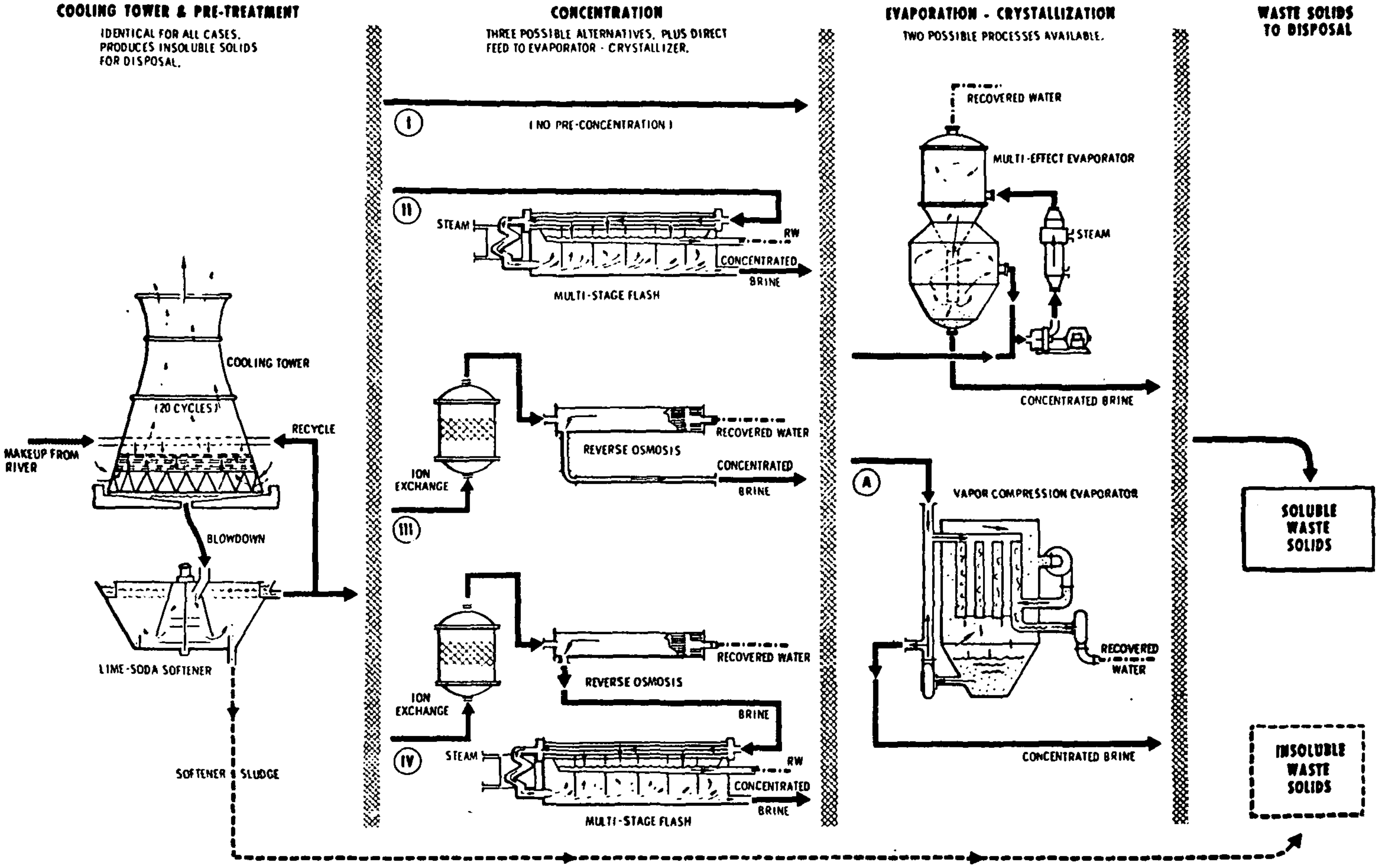


Figure A-VII-20 Possible Combinations of Concentration and Evaporation-Crystallization Processes for Complete Treatment of Cooling Tower Blowdown coagulant, the sludges will contain aluminum hydroxide together with whatever organic or inorganic colloids have been coagulated by the alum. Sludges from lime softening contain primarily calcium and magnesium carbonates and hydroxides. Sludges from filter backwash operations reflect the processes that preceded the filter and differ only to the extent that filter backwash is generally a periodic operation, whereas sludges from setting basins are withdrawn more or less continuously.

Sludges will generally contain between 0.5 and 5.0% of suspended solids. Accepted treatment techniques in the water and wastewater treatment industry consist of hydraulically thickening these sludges to about 10 to 15% solids content. Following thickening, the sludges can be further dewatered by land disposal, centrification, filtration, or incineration. Figure A-VII-21 shows three clarifier waste systems. The supernatent from sludge thickening is generally returned to the original solids separation unit.

Ion Exchange Wastes

Ion exchange resin beds must be regenerated periodically in order to maintain their exchange capacity. For cation resins, the most common regenerant is sulfuric acid. For anion resins, the common regenerant is sodium hydroxide, although ammonium hydroxide is used in some plants. Since powerplant practice is to use excess amounts of regenerants, the waste streams contain primarily sulfuric acid and sodium hydroxide, together with the ions removed from the water during the exhaustion cycle. The waste stream also includes rinse water, that is water passed through the resin beds to remove all traces of regenerant. Typical practice is to regenerate ion exchange units whenever a specified exhaustion has been reached while the units are in service. Figure A-VII-22 shows a simplified flow system.

Waste regenerants and rinses from both the cation and anion resins are normally collected in a neutralization tank and the pH is then adjusted to within the range of 6.0 to 9.0 on a batch basis by the addition of sulfuric acid or sodium hydroxide as required. If any precipitates are formed after neutralization, they are separated from the liquid by settling or by filtration. Figure A-VII-23 shows a neutralization pond.

The neutralized wastes are high in TDS and would require further treatment before they could be used for other water uses requiring low TDS water. However, they are suitable for use as makeup for closed condenser cooling systems or

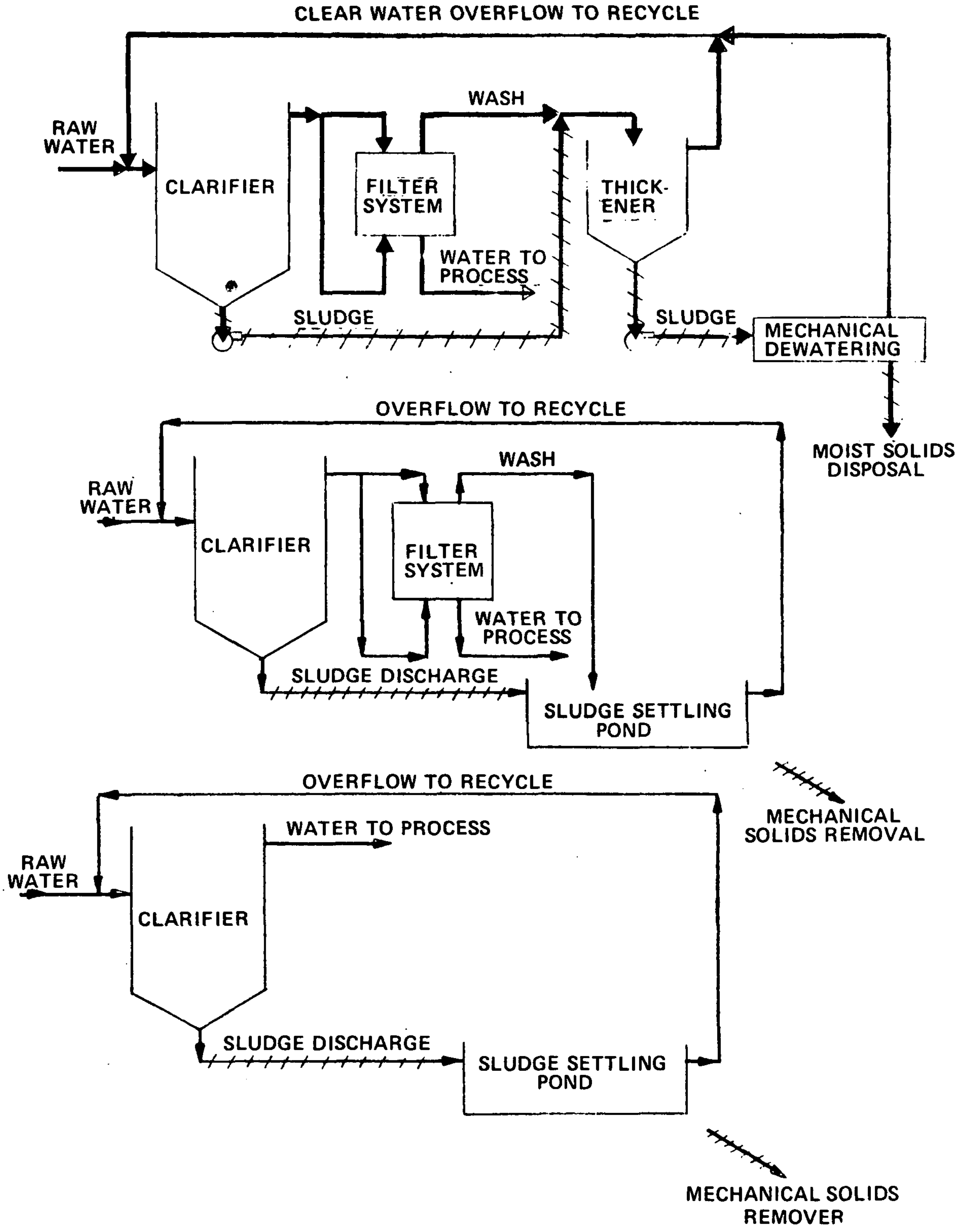


FIGURE A-VII-21CLARIFICATION WASTE TREATMENT PROCESSES

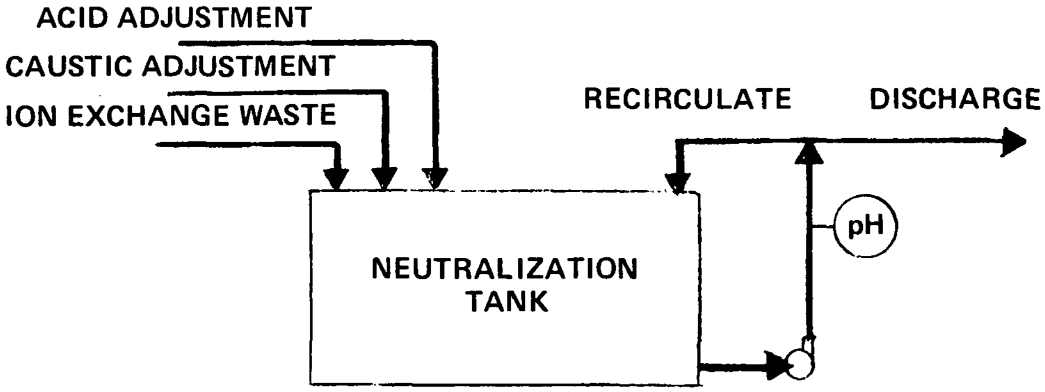
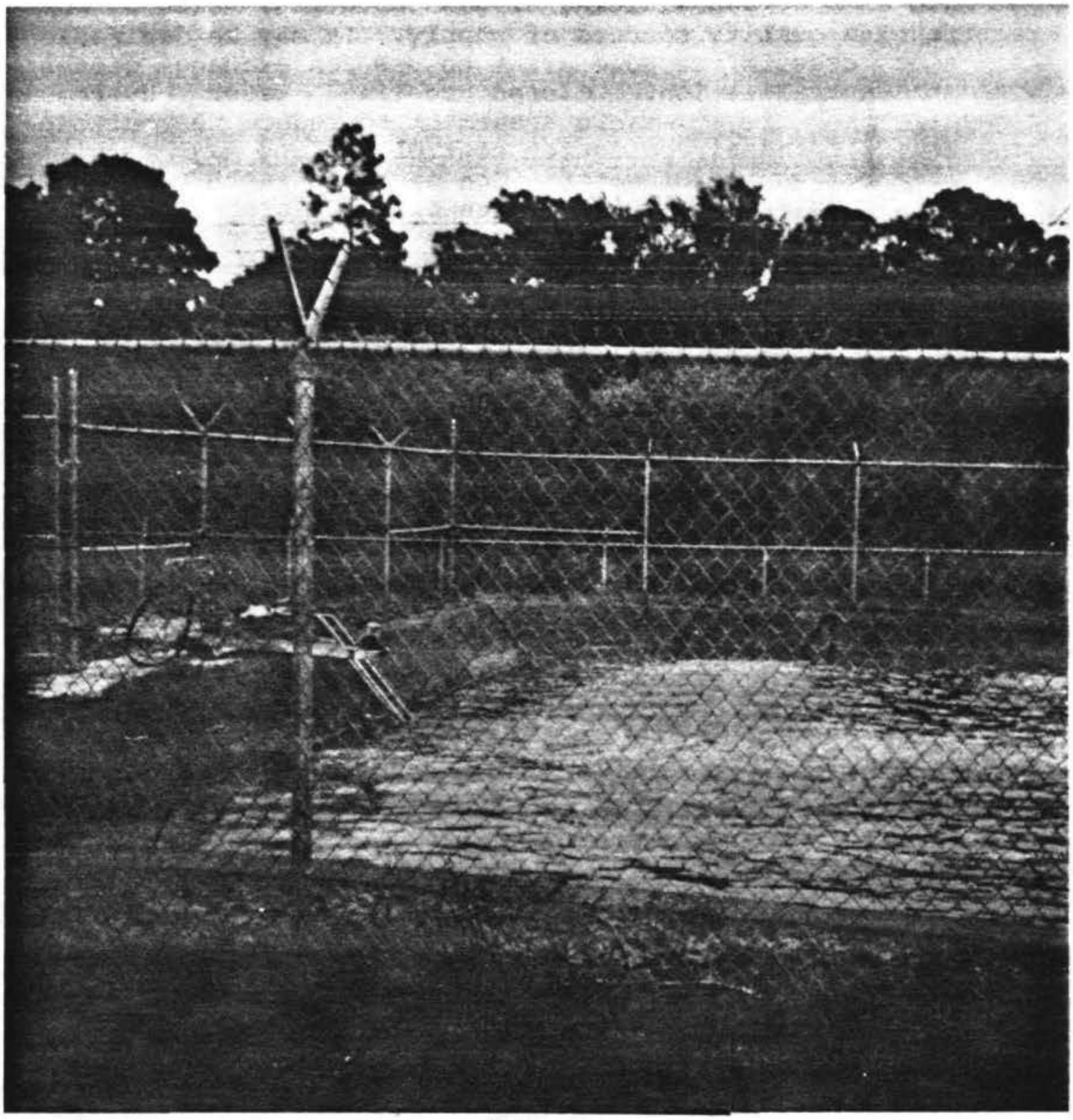


FIGURE A-VII-22 ION EXCHANGE WASTE TREATMENT PROCESS



NEUTRALIZATION POND

Figure A-VII-23

for such uses as ash sluicing or gas scrubbing, which do not require high quality sources of supply. It may be desirable for some uses in the powerplant to use ion exchange wastes without neutralization. Closed cooling water systems generally require some acid treatment to reduce the buildup of alkalinity and air pollution control devices may require an alkaline source of water. Ion exchange waste therefore can often form an economical source of low grade acid or caustic for other uses in the plant.

Substantial reductions in the volume of demineralizer wastes can be achieved by the use of systems which substitute reverse osmosis (RO) or electrodialysis combined with ion exchange (IE) for systems using ion exchange alone. One study shows that RO plus IE systems are less costly than IE systems alone for total dissolved solids of 500 mg/l as $CaCO_3$ in the natural water available. The study is based on 100,000 gallons/day product capacity, no labor costs, and a waste disposal cost of $5/1000 gallons.[383] A 250 gpm product capacity RO system has been recently installed at plant no. 5405. The available water total dissolved solids level is 750 mg/l as $CaCO_3$. The system is designed to reduce the dissolved solids level of pretreated river water to the range for which the conventional resin-bed deionizers are designed.[384]

Evaporator Blowdown

In those plants still utilizing evaporators to produce boiler feedwater makeup, the blowdown from the evaporator contains the salts of the original water supply in concentrated form, but generally still in the solution phase. Treatment is similar to the treatment of ion exchange wastes by adjusting the pH to the neutral range of 6.0 to 9.0 with sulfuric acid or sodium hydroxide. If precipitates are formed during neutralization, these are removed by sedimentation and filtration.

As for ion exchange wastes, the most desirable method of disposal is by reuse within the plant for applications not requiring low TDS sources of supply.

Boiler or PWR Steam Generator Blowdown

Since the quality of the boiler feedwater must be maintained at very high levels of purity, the blowdown from these units is generally of high quality also. Boiler blowdown seldom exceeds 100 mg/l TDS and in most cases is as low as 20 mg/l. For most plants, the quality of the boiler blowdown is better than the quality of the raw water supply, whether it be from a natural source or a municipal water system. The most desirable reuse of boiler blowdown is therefore as makeup to the demineralization system.

Boiler blowdown is usually slightly alkaline, but because of the low TDS level, the pH changes very readily. Neutralization is generally not necessary for any of the forms of reuse previously discussed in this section.

Periodic Wastes

Maintenance Cleaning Wastes

All heat transfer surfaces require periodic cleaning and the usual method of cleaning boiler tube internals is to contact these surfaces with solutions containing chemicals which will dissolve any scale or other deposits on these surfaces. Cleaning operations utilizing water include cleaning of the fire side of boiler tubes, the air preheater, the cooling water side of the condenser, and other miscellaneous heat exchange equipment.

Modern steam generators do not permit inspection of areas most likely to be in distress due to internal deposits, nor can they be cleaned mechanically. Hence, the only practical and generally accepted method of cleaning is by chemical means.[377]

Boiler cleaning wastes pose special problems of disposal. In order to be effective, the chemicals used for cleaning must form soluble compounds with the scale and deposits on the surfaces to be cleaned. Since scale is evidence of the precipitation of an insoluble compound, the cleaning solution must somehow change that solubility. The most common means of accomplishing this objective is by extremes of pH and strong oxidation potential. Where acids are utilized as cleaning agent, there is the additional problem of metals being dissolved into the cleaning solution.

Cleaning of heat transfer surfaces is a relatively infrequent operation. The rate of deposition determines the frequency. However, no general agreement exists as to how to determine when the point has been reached which calls for cleaning. Most operators clean on a time schedule, frequently established by trial and error. A majority of those that do not clean on a time schedule remove tube sections to gauge the amount of deposition.[377] Boilers are usually cleaned not more than once per year. Some of the auxiliary units may be cleaned twice a year. Cleaning operations are scheduled in advance in order to minimize the effect of the outage on the ability of the utility to meet the demands for electric power.

Powerplants use essentially two types of cleaning solutions. One type is an acid solution, usuallly hot hydrochloric acid, used to clean the water side of the boiler tubes. Hydrochloric acid cleaning is the cheapest and most effective of the cleaning methods, but requires a larger volume of water and takes longer than methods employing other chemicals. Citric and phosphoric acids are also used, primarily because they involve less outage time than hydrochloric acid. Fireside cleaning of boilers and cleaning of air preheaters is accomplished using alkaline solutions, primarily containing soda ash.

Many utilities discharge their cleaning wastes with once-through condenser cooling water, relying on the high dilution ratio to minimize adverse effects of the discharge. Some utilities collect spent cleaning solutions in storage basins or ash ponds and adjust the pH to the neutral range. This causes the precipitation of some of the less soluble compounds. The supernatent is discharged to the receiving water and the solids are removed from the basin when this becomes necessary. This technique is followed at plant no. 2525, which neutralizes its cleaning wastes before discharge to a large settling pond. Plant no. 3601 also collects cleaning wastes in a storage basin, applies lime or caustic for neutralization, and then discharges the supernatent.

Current control and treatment technology for cleaning wastes involves segregation of the waste, chemical treatment to bring the pH into the neutral range, and separation of any precipitates resulting from the neutralization.

Ash Handling Wastes

Most of the coal-fired plants use ash ponds. The data from existing ash settling ponds was reviewed in Part A Section V of this report. Of the plants for which useful data was obtained, 28% have a negative or zero net discharge of total suspended solids from the ash pond. For example, Federal discharge permit applications for four of these stations are given in Table A-VII-12. The data of one of these, plant no. 0107, were verified by analyses of samples taken at the site by EPA personnel. These data are summarized in Table A-VII-13.

Sedimentation lagoons are commonly used at steam electric powerplants, however, some plants employ configured tanks.

Table A-VII-12

ASH POND PERFORMANCE

Source: Federal discharge permit applications

Plant No.	Concentration Total Suspended Solids, mg/l	
	Plant Intake	Effluent
0104	31	22
0105	35	6
0106	10	3
0107	13	10

Table A-VII-13

SUMMARY OF E.P.A. DATA VERIFYING ASH POND PERFORMANCE, PLANT NO. 0107

Location	TSS mg/l	pH	Aluminum* mg/l	Chromium* mg/l	Copper* mg/l	Iron* mg/l	Mercury* mg/l	Zinc* mg/l
Intake	22	6.3	0.7	< 0.04	< 0.04	0.5	< 0.04	< 0.05
Inlet to Ash Pond								
● from fly ash	76,440	4.4	1100	1.3	5.1	2500	0.1	2.8
● from bottom ash	4,110	5.6	56	0.1	0.3	112	< 0.04	0.1
Ash Pond Discharge	14	4.3	6.0	< 0.04	0.1	0.6	< 0.1	0.1

* Note: Total

Tanks can be used where space limitations are important. Tanks constructed for solids removal usually have built-in facilities for continuous or intermittent sludge removal. Designs based on maximum flow anticipated can provide the best performance. Equalization can be provided to regulate flow. The retention time required is related to the particle characteristics. Plant No. 3905 employs a settling basin 250,000 sq ft x 5 ft deep to provide a minimum retention time of 24 hours for a waste stream of normally 1,800 gpm (3,300 gpm maximum). The ash pond is 600 acres in area and will contain 6,700 acre ft. Coal used at the plant is pulverized to a size passing 80 percent through a 200 mesh screen. Approximately 80 percent of the ash is discharged as fly ash. No cooling water is discharged to the ash pond. The distance from inlet to outfall is about one mile. The narrow water stream in the pond meanders through the settled ash piles. The reported flow is about 500 gpm.

Nine out of the ten fossil-fueled steam electric powerplants operated by the Tennessee Valley Authority use ash ponds for both fly ash and bottom ash, as well as for other plant wastes such as from boiler cleaning. Effluent samples from these ponds have been taken quarterly over a period of several years. Analyses were performed and reported on numerous parameters including total solids, total dissolved solids and turbidity. Total suspended solids values can be inferred as the difference between total solids and total dissolved solids. A total of 1297 effluent suspended solids sample values were tabulated for 10 plants in the system. Of this total, 1,151 values were less than 100 mg/l, 4 samples were exactly 100 mg/l and only 146 values exceeded 100 mg/l. On a percentage basis, values equal to, or less than, 100 mg/l represented approximately 89% of the total number of values reported. The 95% value for the total of the 1,297 samples was 165 mg/l. Table A-VII-14 summarizes the data from the 10 plants in the system.

An analysis of the data indicates that the effluent suspended solids values reported for Plant No. 2119 were generally higher than the results reported for the other 9 powerplants in the system. Of the total number of 146 samples which were equal to, or exceeded 100 mg/l, 106 were reported by plant No. 2119. Consequently, it was decided to analyze the data, omitting the results from this plant, to determine the percentage of values exceeding 100 mg/l and the 95% value for the other 9 plants. This analysis yielded

Table A-VII-14

ASH POND EFFLUENT, TOTAL SUSPENDED SOLIDS, MG/L

Plant No. and Ash Pond	Flow Rate in GPM	Suspended Solids for 95% of Samples mg/l	No. of Samples Considered	Median Value in mg/l	Average Value of 95% of Samples
2119-P1	1,500	899 or lower	48	128	176
4701	1,700	65 or lower	45	41	23
4704	3,000	39 or lower	41	14	16
4704	3,300	36 or lower	48	13	14
4703	4,000	38 or lower	31	10	14
4705-North	4,500	71 or lower	37	15	20
0111	5,000	86 or lower	36	31	40
2119-P1	6,000	195 or lower	41	62	72
4701	6,500	87 or lower	45	42	42
2119-P1	7,000	184 or lower	12	106	109
4702	7,200	222 or lower	47	57	66
4705-South & 4702	7,500	56 or lower	41	13	16
2119-P1	9,000	309 or lower	47	64	167
2119-P2	12,000	305 or lower	41	70	88
2120	13,000	22 or lower	49	16	21
4706, 0111 & 0112	14,000	61 or lower	47	15	19
2119-P2	15,000	205 or lower	47	53	76
2119-P2	20,000	72 or lower	12	22	30
2119-P2	25,000	205 or lower	48	51	74

the following results:

A. Total number of samples = 985
B. 2 values = 100 mg/l
C. 38 values > 100 mg/l
D. Percentage of values ≥ 100 mg/l = 3.96% to 4.06% of the total of 985 samples
E. 95% value = 93 mg/l

It was generally concluded that this analysis may be more representative of the entire system, since the results from plant No. 2119 appear to be atypical of the data provided by the other 9 plants.

Data on ash pond overflow for 38 plants obtained from discharge permit applications, plant visits, a regional office survey, and other sources indicate that 50 percent of the ash ponds are achieving effluent total suspended solids levels of 30 mg/l. For this same sample, 50 percent of the ash ponds are achieving less than 15 mg/l total suspended solids after allowances are made in the data to exclude total suspended solids in the make-up water. On this net basis, 30 mg/l is being achieved by approximately 75 percent of the ash ponds in the sample.

The Henderson, Kentucky, Municipal Powerplant No. 1 uses a tube settler to achieve over 99 percent removal of total suspended solids from fly ash and bottom ash sluice water. Some details on this systems are presented in Reference 454. Land was not available for constructing conventional removal facilities (an effective surface area of 3,000 square feet would have been required to provide adequate treatment at 1,200 gpm). See Figure A-VII-24.

Tube settlers, manufactured under several proprietary names, consist of numerous plastic tubes about one inch in depth and 24 inches long, mounted in modules and placed in a basin. The tubes, as manufactured, are installed in an inclined position and each tube acts as an individual settling device. With a length of travel of one inch the settleable particles can be removed at a much faster rate than in conventional settling arrangements. The angle of incline allows the sludge to slide downward to the basin scrapers. Thus, the tubes are self-cleaning when operating under design conditions.

Preliminary testing indicated that a hydraulic loading rate of 1.75 gpm per sq ft would produce a good quality effluent. Consequently this method of ash removal was recommended for the project. In the final design, a hydraulic loading rate of 1.6 gpm per sq ft was used. Accordingly, an effective surface area of 750 square feet was required. Modules made by Permutit Co., Division of Sybron Corp. were selected.

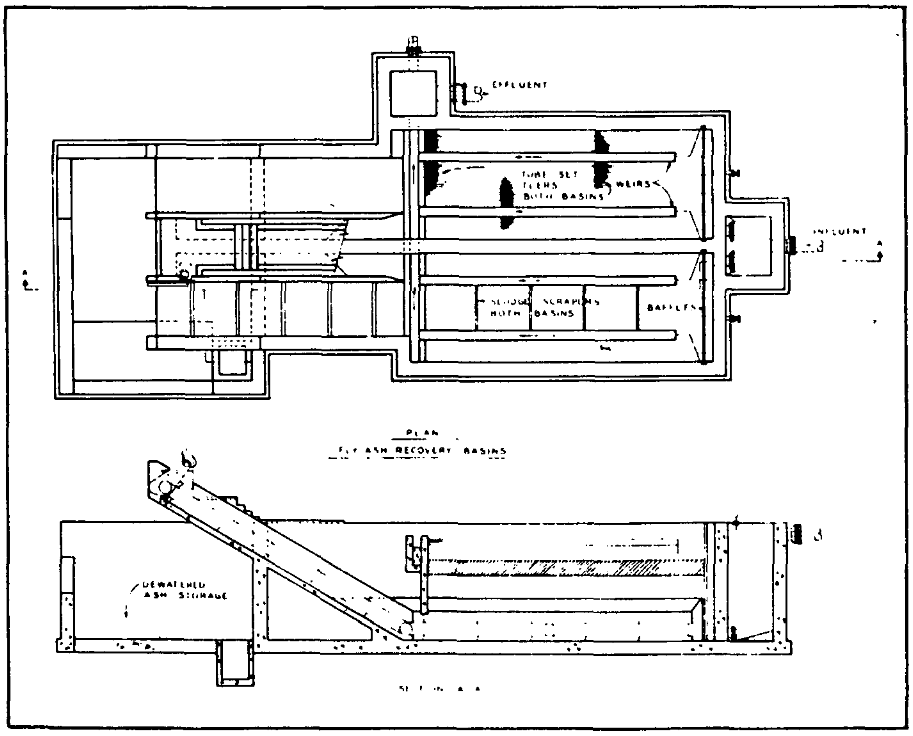


Figure A-VII-24 Tube Settler for Ash Sluice Water at Henderson, Kentucky[454] Municipal Power Plant No. 1

Two basins were designed, each capable of treating one-half the design flow. However, all piping and launders of each basin were designed to carry the entire flow in case one basin is out of service. Each basin has an influent baffle which serves two purposes: distributing the flow across the basin and trapping all floatable particles. The settled ash is removed with mechanical sludge scrapers furnished by Envirex, Inc., a Rexnord Co. The scraper travels up a 30 degree inclined plane at the effluent end of each basin. As the sludge is moved up the incline, it continues to dewater until it discharges into a sludge storage area. Any drainage from the ash storage area is pumped back to the basin influent. Although the sludge is quite wet, it is easily handled with a high-loader. Ultimate ash disposal is by haul to a landfill as before.

After the settling basins were placed in operation, composite samples were collected during several cycles of operation to determine the efficiency of the new system. The results of the sampling program are shown in Table A-VII-15 and reflect the performance of the new basins only. The turbidity and suspended solids concentrations of the river during the sampling program were 64 JTU and 42 mg/l respectively.

Maintenance requirements for the system have averaged about 16 manhours per week. The normal duties of the maintenance personnel include hauling of the removed fly ash, preventive maintenance and general clean-up of the facilities. The power requirements include two 2-hp scraper drives and one 1/4-hp sump pump. The total construction cost was $179,000.

pH adjustment has been discussed earlier for other waste streams. Some plants provide pH control on ash pond effluent. In pH adjustment, addition of chemicals (such as lime) to the pond should be carried out such that adequate mixing and settling is provided in the pond. This can be achieved by separating the pond in two areas by use of overflow weirs.

In most of the existing plants, a combined once-through sluicing system is used to transport both the fly ash and the bottom ash. Specific data was obtained for five plants which utilize recirculating ash sluicing systems. In all the cases, blowdown of the system is practiced to minimize deposition of dissolved solids as well as to minimize corrosive effects on the distribution pipes.

Table A-VII-15

Performance of Tube Settlers for Ash Sluice Water[454] (Results of Composite Sampling)

Sample Number	Turbidity, JTU		Total Suspended Solids, mg/l		
	Influent	Effluent	Influent	Effluent	% Removal
1	1300	2.7	7910	4	99.9
2	360	6.2	1175	4	99.7
3	750	19	2815	26	99.1
4	750	10	5200	18	99.7
Average	790	9.5	4275	13	99.7

At plant No. 3626 the fly ash is handled dry by a pressurized collection system, and the bottom ash is collected hydraulically. Once per shift the bottom ash is sluiced from the furnace bottom for settling. Water for the next sluice is recycled from the effluent of the sedimentation unit. The settled solids are periodically drained for disposal. The system is designed for complete recycle, with blowdown achieved by water retained in the settled solids. The recycle stream concentrations have equilibrated and the system has operated successfully for a number of years. The total makeup to the recirculating system has been reported as 230 gpd/Mw. A similar system in operation at plant no. 3630 was installed as a retrofit. Bottom ash from the combustion of pulverized coal at plant no. 3630 is trucked from the plant site by a purchaser. The make-up water rate is about 20 gpd/Mw.

Figure A-VII-25 shows the flow diagram for the system at plant No. 3630. The blowdown flow has been reported as 198 gpd/Mw. Figure A-VII-26 shows the flow diagram for the recirculating system at plant No. 5305. The blowdown flow is 165 gpd/Mw. The recirculating systems at plant Nos. 5305 and 3626 are shown in Figures A-VII-27 and A-VII-28, respectively.

In two plants within the companies represented on the UWAG Chemical Cost Task Group which have recycling ash sluicing systems, blowdown flows of 600 gpd/Mw and 960 gpd/Mw are used.

Utilizing the data from these five plants (20,165,230,600 and 960 gpd/Mw), the three lowest values of which conservatively include water lost in evaporation and water removed with the ash solids, the average blowdown for a recirculating ash system is about 400 gpd/Mw. If it is assumed that 5000 gpd/Mw is the recirculating flow requirement for handling bottom ash, the average blowdown flow of approximately 400 gpd/Mw represents an 8% blowdown flow. Three of the plants are achieving a blowdown flow of less than 250 gpm/Mw which would represent, based on a recirculating flow requirement of 5000 gpd/Mw, a 5% blowdown flow.

Most oil fired plants use dry ash handling, although closed-looped wet systems are also in use. At plant No. 2512, the fly ash sluicing system was designed to be a closed system. The ash collected by the precipitators is sluiced from the hoppers to two concrete ponds. Suspended solids settle out in the ponds and a relatively clear liquor is returned to

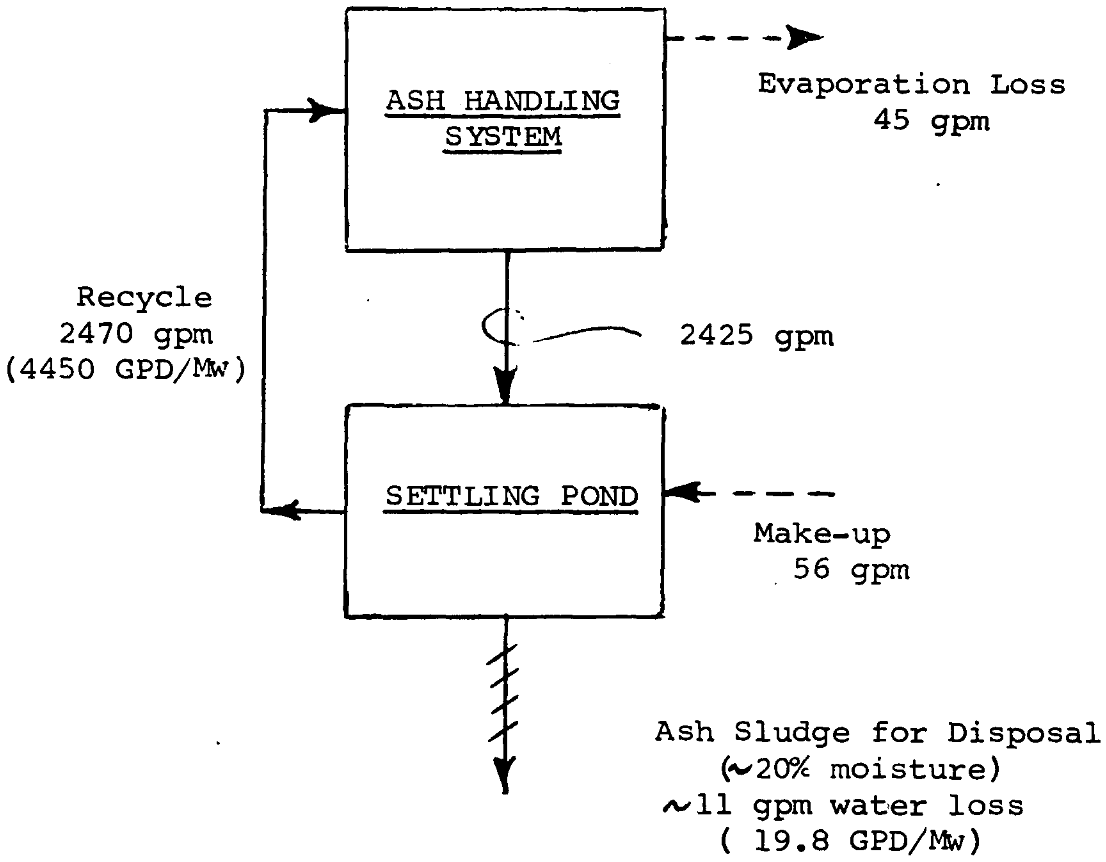


Figure A-VII-25
FLOW DIAGRAM
RECIRCULATING BOTTOM ASH SYSTEM AT PLANT NO. 3630

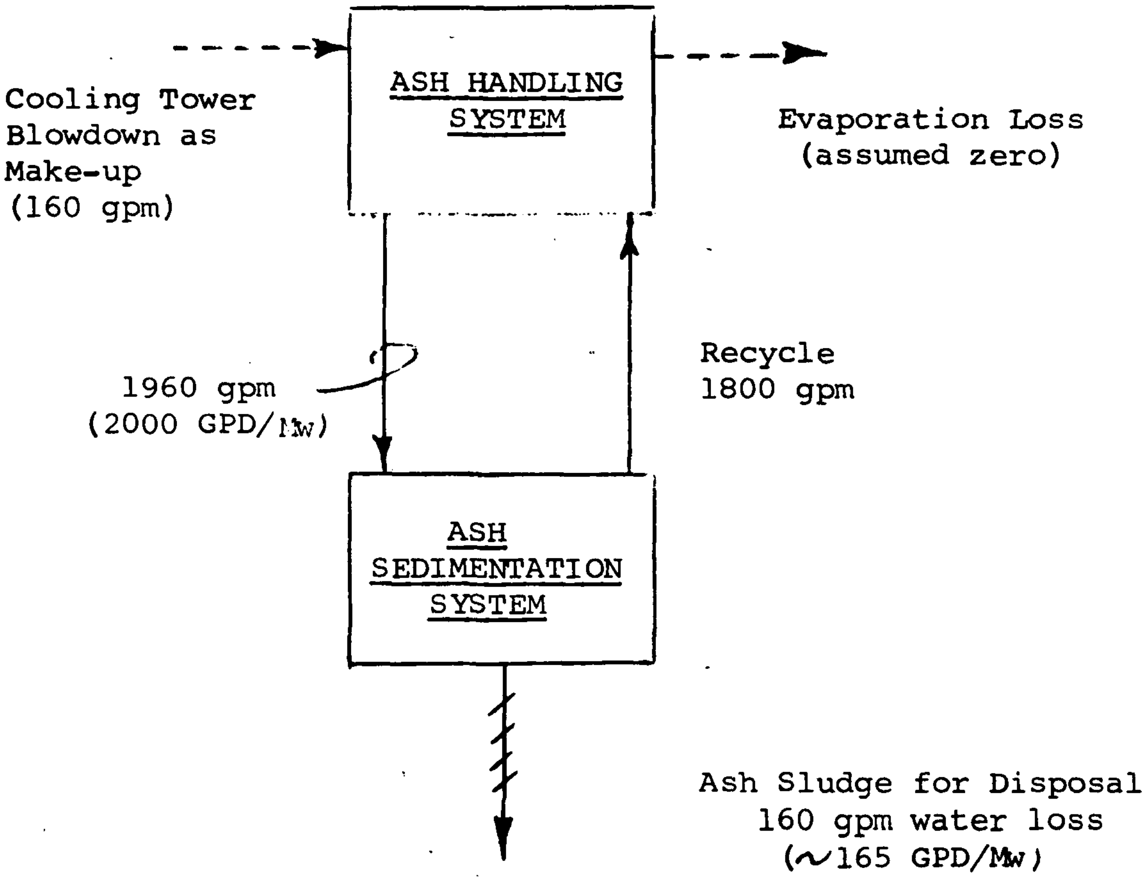
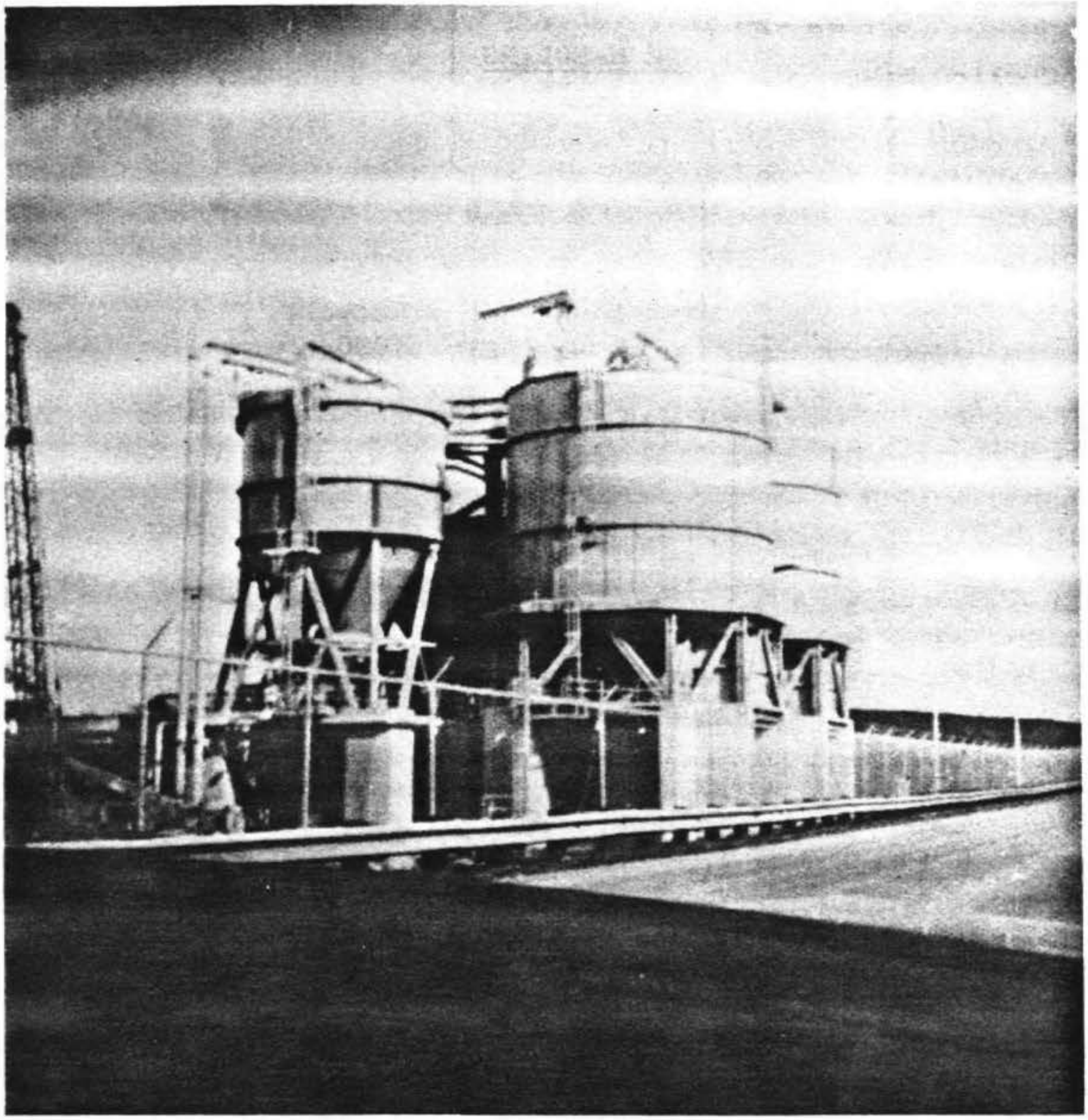
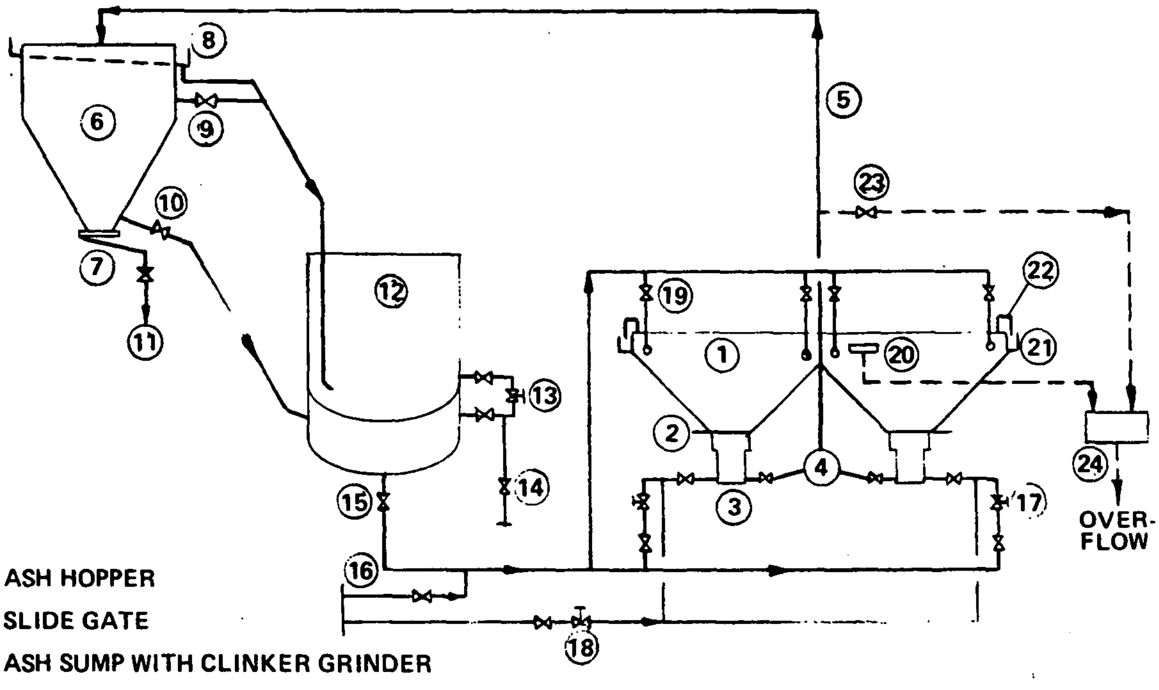


Figure A-VII-26
FLOW DIAGRAM
RECIRCULATING BOTTOM ASH SYSTEM AT PLANT NO. 5305



ASH SEDIMENTATION SYSTEM
PLANT NO. 5305

Figure A-VII-27



1. ASH HOPPER
2. SLIDE GATE
3. ASH SUMP WITH CLINKER GRINDER
4. ASH PUMP
5. ASH PUMP DISCHARGE TO HYDROBIN
6. HYDROBIN – THIS IS WHERE ASH IS SEPARATED FROM WATER.
7. UNLOADING OF ASHES INTO TRUCK
8. HYDROBIN OVERFLOW TROUGH
9. UPPER DECANT LINE
10. LOWER DECANT LINE
11. HYDROBIN DRAIN
12. SURGE TANK
13. LET DOWN LINE – THE REGULATING VALVE IS NOT IN USE. THIS IS NOW A HAND OPERATION TO LET WATER INTO LOWER COMPARTMENT OF SURGE TANK.
14. HOUSE SERVICE SUPPLY LINE – NOT NORMAL MAKEUP.
15. LINE FROM SURGE TANK TO ASH SUMPS
16. HOUSE SERVICE SUPPLY LINE – AT PRESENT DATE IS SOURCE OF MAKEUP – HAND OPERATION
17. REGULATING VALVE TO ASH SUMP
18. HOUSE SERVICE SUPPLY LINE – NO LONGER IN USE.
19. HOPPER WASH DOWN LINE – A MEANS OF PUTTING WATER INTO ASH HOPPERS FROM MAIN CYCLE.
20. ASH HOPPER OVERFLOW
21. BOILER SEAL TROUGH – WATER OVERFLOWS FROM HERE TO ASH HOPPER THUS ANOTHER SOURCE OF MAKEUP WATER.
22. BOILER FEED PUMP HYDRAULIC COUPLING COOLING WATER
23. DRAIN BACK LINE – DRAINS ASH PUMP DISCHARGE LINE.
24. OVERFLOW TROUGH – DISCHARGES INTO CIRCULATING WATER DISCHARGE.

FIGURE A-VII-28 ASH HANDLING SYSTEM (PLANT NO. 3626) the precipitators to sluice additional ash to the ponds on a continuous basis. Due to excessive rainfall and leakage of pump sealing water, the system requires a blowdown of approximately 132.5 cu m (35,000 gal) per week. The blowdown is treated in another clarification pond where the solids are allowed to settle. The effluent from this pond goes to a neutralizing tank for pH adjustment, and is settled prior to discharge. The system is shown on Figure A-VII-29.

The settled solids are intermittently dug out and sold to reclaiming companies for vanadium recovery. The cost of the ash handling system is estimated at $461,000.

The above plant is presently investigating a vacuum filter system for continuous withdrawal and treatment of settled solids, to replace the intermittent withdrawal system now used.

At plant No. 1209 fly ash from the mechanical collectors is recirculated to the boilers for reburning. Accumulated bottom ash is periodically removed during maintenance and sold for the vanadium content. The utility representatives indicate that other plants in their system utilize similar ash handling techniques.

Plant No. 3621 employs the same type of dry bottom ash handling and reinjection of fly ash as mentioned above. The oil burned is Bunker "C" - Venezuela oil, with an ash content of 0.1%, a sulphur content of 3%, and a vanadium content of 300-400 ppm. A magnesium oxide fuel additive is used and it is estimated that bottom ash is 30%, and fly ash is 70%, of the total ash and additives residue. The following factors influenced the utility's choice of ash handling system: in a wet ash handling system it is estimated that 74.6% of the oil ash is soluble in water, and 30-40% of this ash remains in solution upon settling unless the detention time is very great - hence a large settling area requirement; oil ash sluice is expected to be acidic (pH 3.5- 4) and may cause corrosion and maintenance problems; the dry bottom ash collection system would allow a credit for the sale of this ash for its vanadium content of about $ 0.001 per g ($0.50 per lb).

Plant nos. 5509 and 5511 employ completely recirculating wet fly ash handling systems. Dry bottom ash systems are in use at a few plants.

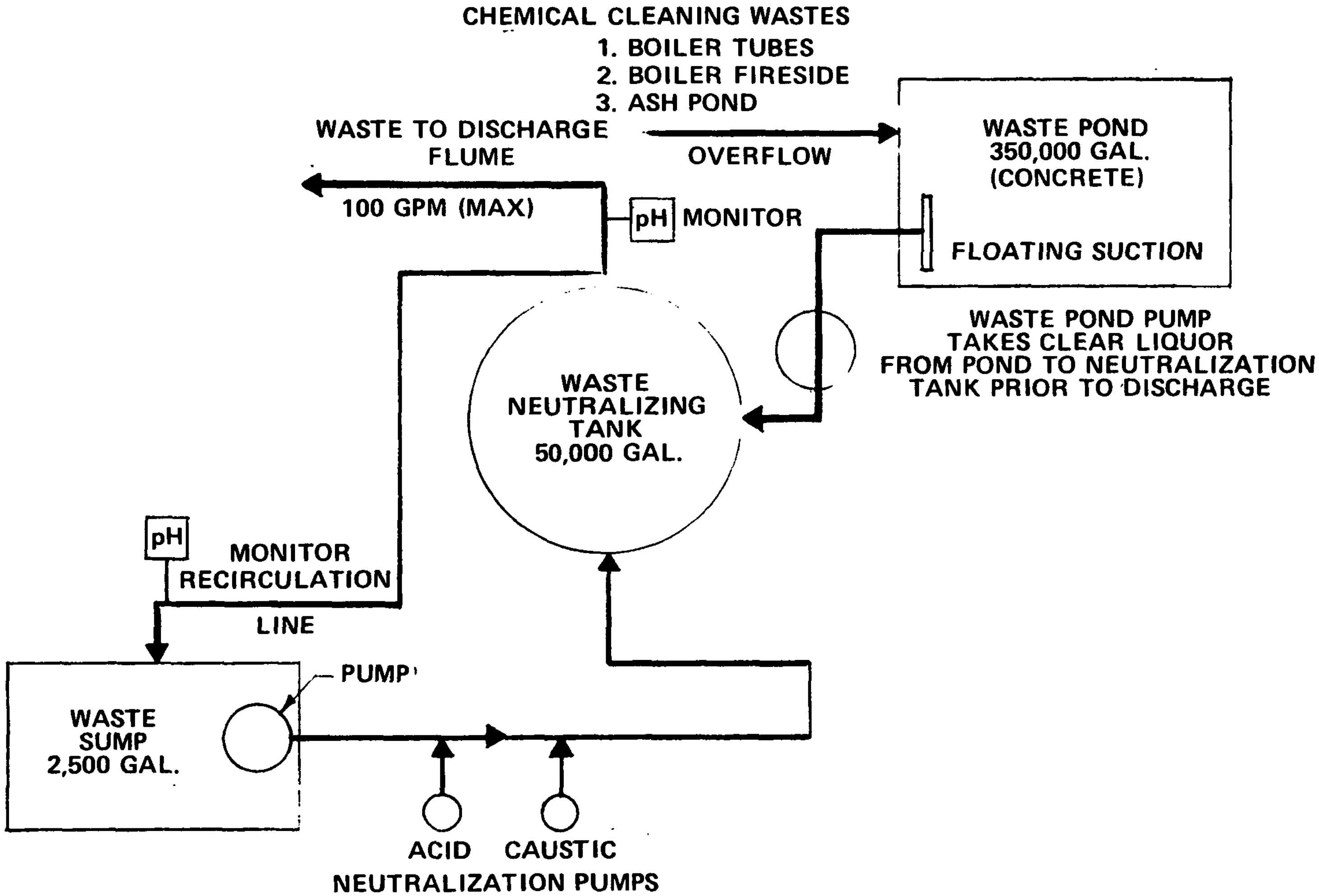


FIGURE A-VII-29ASH HANDLING SYSTEM OIL FUEL PLANT (PLANT NO. 2512)

Coal Pile Runoff

In areas where water evaporation rates are higher than precipitation rates, it is possible to direct coal pile runoff to a storage pond. These ponds may be provided with an impervious liner to avoid leakage that may contaminate a ground water aquifer. Since the amount of runoff depends on rainfall, for an average annual rainfall of 100 cm (40") a flow rate of 100,000 cubic meter (26.4 million gallons) per year could be expected for a one hundred thousand square meter (25 acres) storage pile. However, a precipitation of 5 cm (2") in one hour is also possible resulting in 5000 cu m (1.32 million gallons) runoff. Inasmuch as the evaporation of water is dependent on the surface area of pond, large pond areas will be required for these runoff flows. Furthermore, a leaping weir or similar device can be used to retain the potentially significantly polluting portions of storm rainfall and to divert the remaining relatively nonpolluting portions of the storm.

Storage ponds for retention and treatment of coal pile runoff should be designed for local weather conditions. The design basis of the pond should be complete retention of runoff resulting from a storm which occurs once in ten years. Piping and/or open channels used for collection of runoff from the coal pile should be designed to bypass all flow which exceeds the design basis of the storage pond. Weirs, baffles and regulators such as utilized in combined municipal sewer systems may be employed to bypass excess flow and avoid overloading of the storage pond.

The runoff flows are also critically dependent upon the coal pile area in a plant. For example, the area required for a 90 day coal supply and for other storage functions, such as alkali for electrostatic precipitators, etc., has been estimated to be 0.02 acres per Mw of generating capacity (Ref: "Considerations Affecting Steam Power Plant Site Selection", Report by the Energy Policy Staff, Office of Science and Technology, US GPO No. 0-325-261 1968). Data were compiled for coal pile area encountered in 10 plants comprising one particluar utility system. The average coal pile area was approximately 0.02 acres per Mw of generating capacity with the full range extending from 0.004 to 0.035 acres/Mw.

Coal pile drainage with pH from 6 to 9 and low dissolved solids can be pumped to an ash pond along with other waste streams, depending upon available area of the pond.

Runoff from coal pile with high acid and sulfate content can be neutralized by lime, limestone or soda ash. Any of these chemicals used for the neutralization process involves essentially the same unit operation. A typical sequence of unit operation is (a) holding (b) adding the neutralizing agent and mixing (c) sludge settling and disposal. The major difference between soda ash neutralization and lime or limestone neutralization is that soda ash produces a water low in hardness and calcium, but high in sodium. Other chemical parameters are comparable between the three neutralizing agent. Figure A-VII-30 presents the chemical cost for these three chemicals.

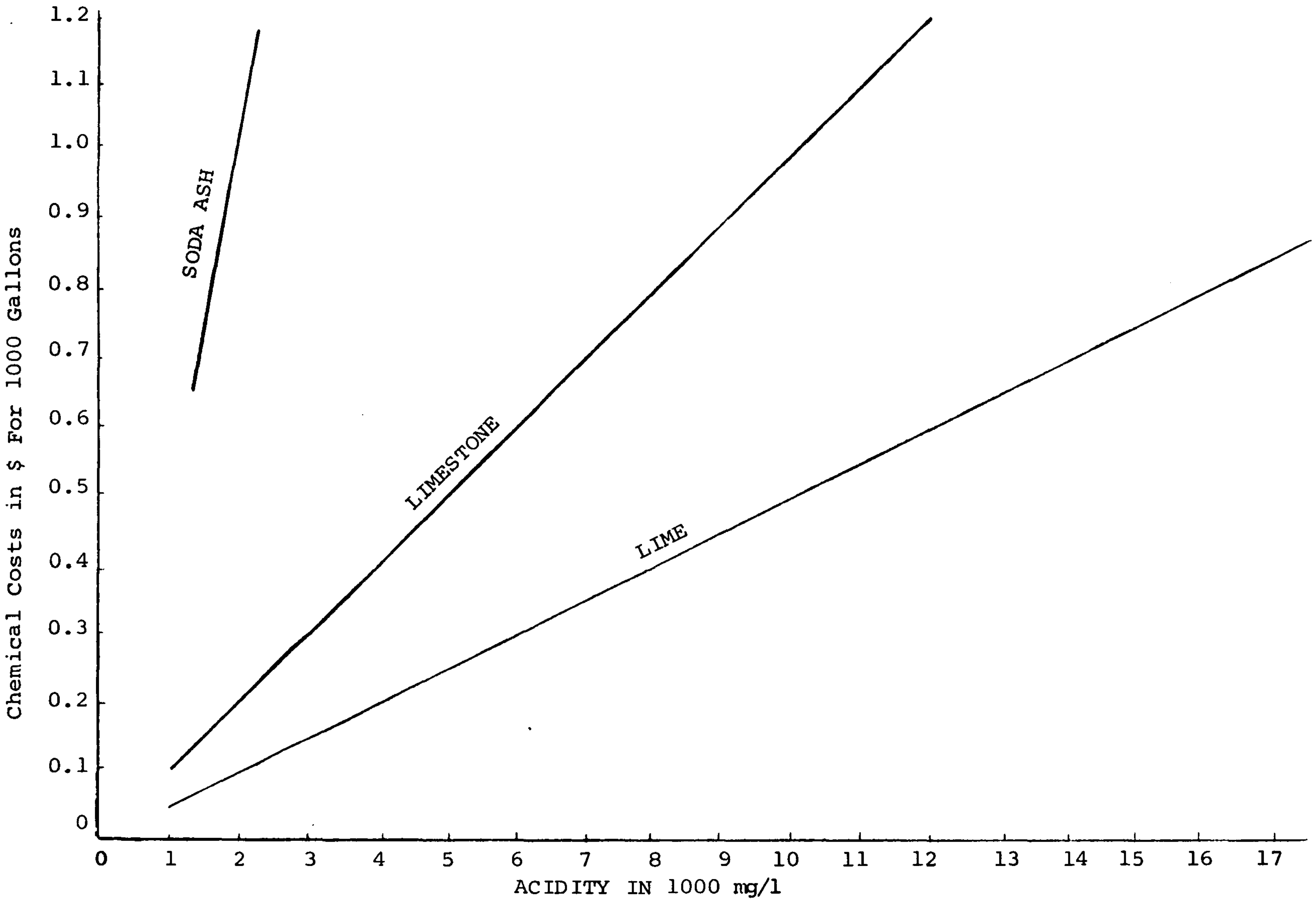
Limestone handling is easier than that of lime because of its low reactivity. Limestone reaction is not very sensitive quantitatively: i.e. small changes in limestone feed rate or runoff quality do not cause large changes in product water quality so that the accuracy of limestone feeding need not be controlled with the precision required for lime. Unlike lime, accidental over treatment is not a pollution problem with limestone because of its low solubility.

A major disadvantage in limestone neutralization can be attributed to the slow oxidation rate of ferrous iron and consequently lower rate of settling. The rate of settling can be increased by the addition of coagulant aids. Figure A-VII-31 and Figure A-VII-32 present a comparison of lime, limestone and soda ash reactivities and settling rates respectively. For a coal pile runoff containing ferrous iron ($FeSO_4$) and free acid (H_2SO_4), the overall neutralization reaction using limestone ($CaCO_3$) can be represented in the following simplified manner:

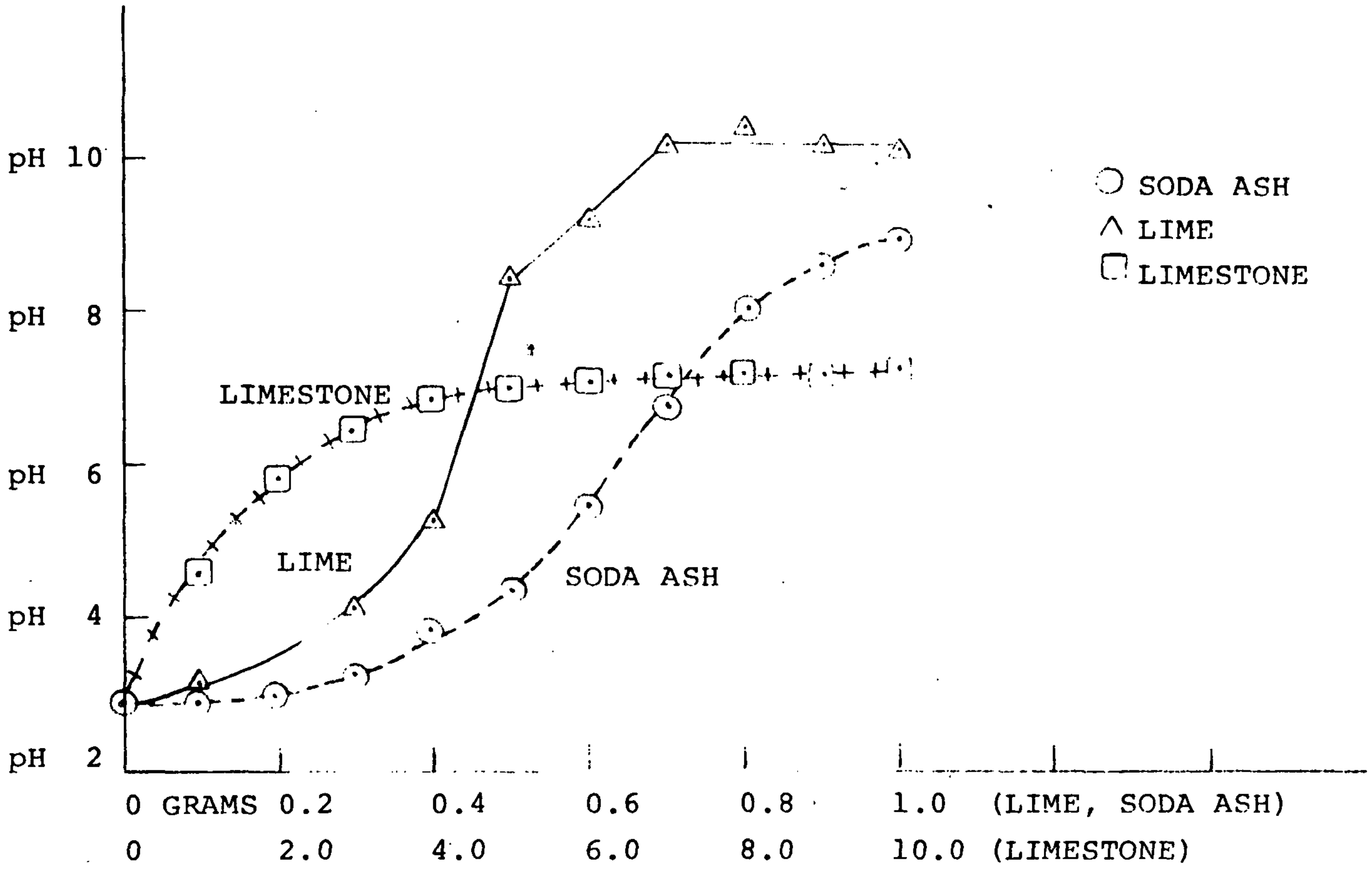
$$3CaCO_3 + 2FeSO_4 + H_2SO_4 + 0.5\ O_2 + 2H_2O = 3CaSO_4 + 2Fe\ (OH)_3 + 3CO_2$$

A method of collecting and neutralizing coal pile drainage is to excavate a channel around the coal pile large enough to have a 10 minute detention time. The bottom of the channel should contain a limestone bed for neutralizing the acid content of the runoff. The channel should be sloped so as to have the runoff drain to a sump from where it can be pumped or gravity fed to a holding pond prior to discharge.

Insoluble material or precipitated products from neutralization can be separated by sedimentation or filtration. The removal of solids by sedimentation has been described earlier. Figure A-VII-33 shows a typical coal pile, with a runoff collection ditch around the perimeter. Plant no. 3630 has a retrofit system for collecting and filtering coal pile drainage. The coal pile trench is designed to handle a 15-hour, once-in-36-years rainfall (3.9



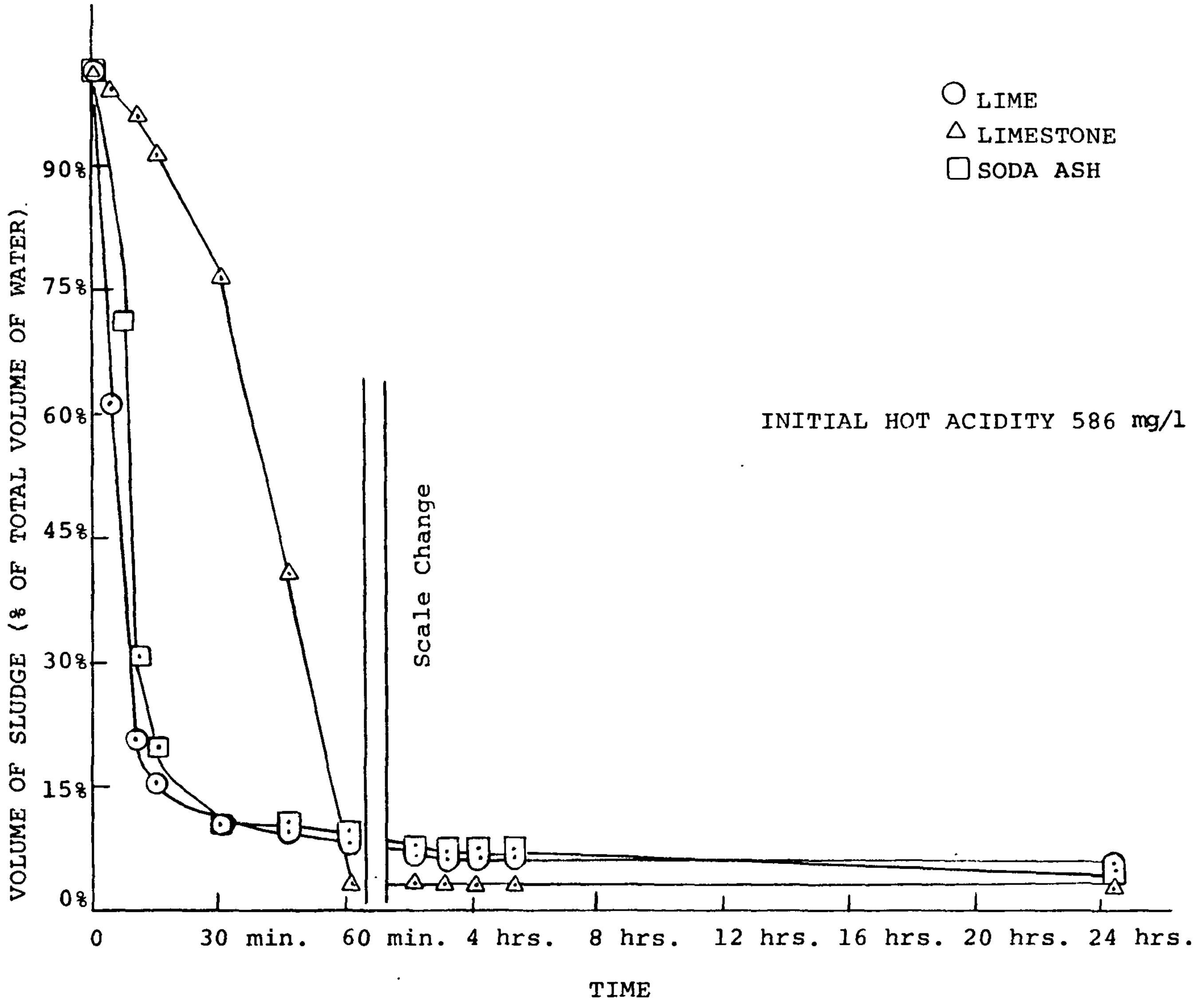
COST OF NEUTRALIZATION CHEMICALS
(From Reference 313)
FIGURE A-VII-30



GRAMS ADDED TO ONE LITER OF RUNOFF (From Reference 313)
(INITIAL HOT ACIDITY = 619 mg/l)

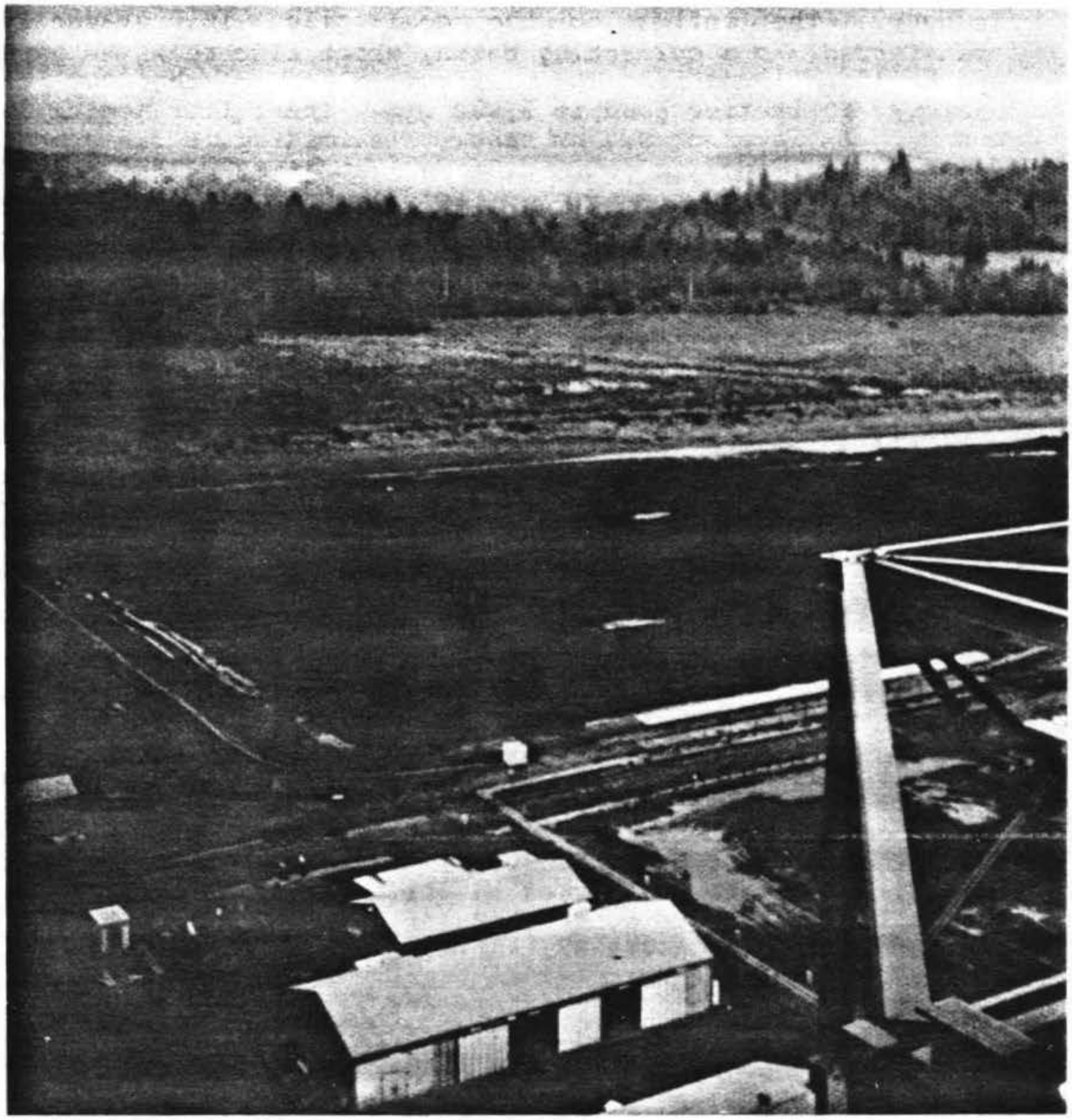
COMPARISON OF LIME, LIMESTONE, AND SODA ASH REACTIVITIES

FIGURE A-VII-31



COMPARISON OF SETTLING RATE (From Reference 313)

FIGURE A-VII-32



COAL PILE
PLANT NO. 5305

Figure A-VII-33

inches). The inflow to the coal pile is gradually transferred to a collecting basin, which also receives yard and building drains. The maximum flow to the 100 ft diameter filtering pond is 2,400 gpm. The filter medium is a 4 ft deep layer of 0.4 mm sand. The loading is 3.5 gpm/sq ft and is designed to achieve 35 mg/l total suspended solids in the effluent. A design for lower effluent total suspended solids would involve a deeper bed, a better filter media, or a larger bed area. This filter has achieved effluent total suspended solids levels of 15 mg/l or less over approximately 75 percent of the storm events to date. The trench and collecting basin construction costs were about $750,000 and the filtering pond about $150,000.

Floor and Yard Drains

Floor drains from a coal-fired generating station can be collected and pumped directly on to the coal pile so that the oil present in the drainage stream is absorbed by the coal and burned with it. The water will serve the purpose of keeping the pile wet in order to avoid spontaneous combustion. Floor drains from plants using a fuel mixture or fuel other than coal, can be neutralized (if necessary) by lime or acid to bring the pH between 6 and 9.0. Oil will be removed by passing the stream through an air flotation unit or an oil-water separator (Figures A-VII-34, 35). If the drains contain high levels of TSS, sedimentation techniques described earlier can be used. An air flotation unit used for floor and yard drains is shown in Figure A-VII-36. Contaminated stormwater runoff can be treated in a similiar manner. Stormwater collected in oil storage tank basins is generally held for controlled discharge to an oil-water separator (Figures A-VII-37, 38).

API - type oil - water separators are being used at plant nos. 3626, 5105, 1209, and 3702 to reduce oil content down to 15-20 mg/l. A dissolved air flotation unit is used at plant no. 0610. Certain preventative measures can be applied to prevent spillage of oil and the entrance of oil into the plant drainage system. For example, plant No. 1201 employs inflatable "stoppers" in the entrance to plant floor drains to trap spilled oil and so that it may be removed before entering the floor drain system.

Air Pollution Control Devices

The nonrecovery alkali scrubbing process is a closed-loop type, and the process employs recycle lime scrubbing liquor. The process requires a make-up water for saturating the boiler gases. Consequently, the liquid effluent associated

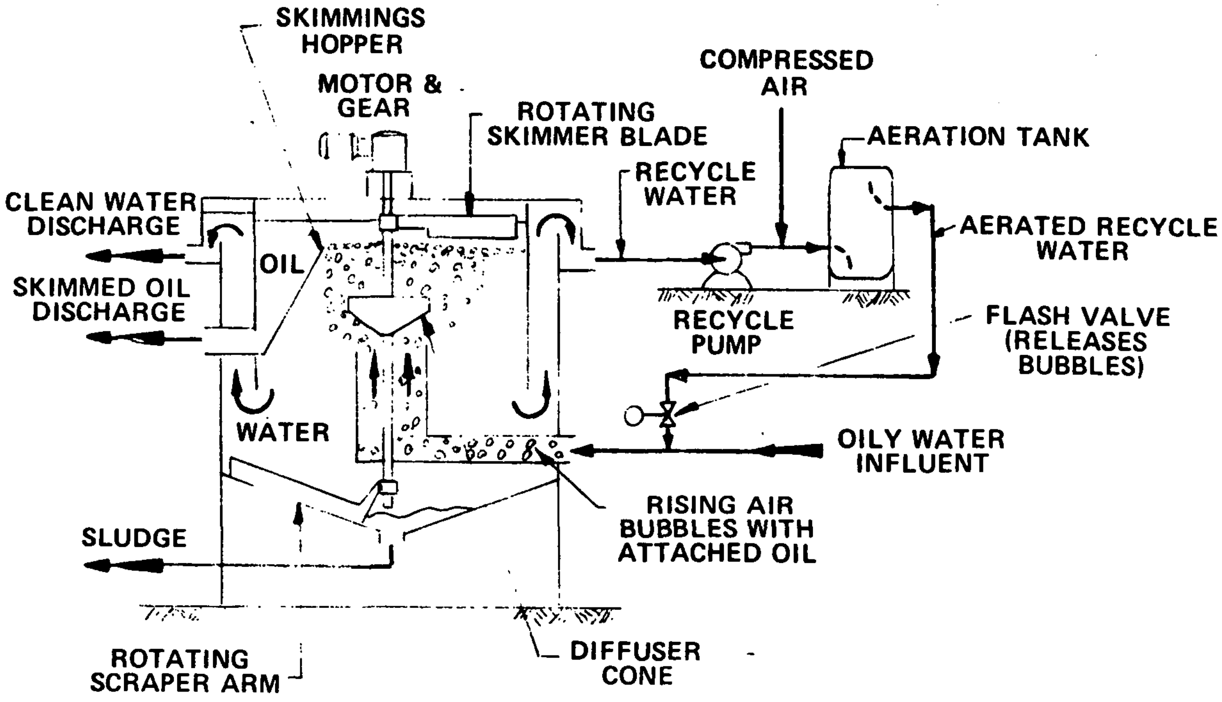


FIGURE A-VII-34 CYLINDRICAL AIR FLOTATION UNIT

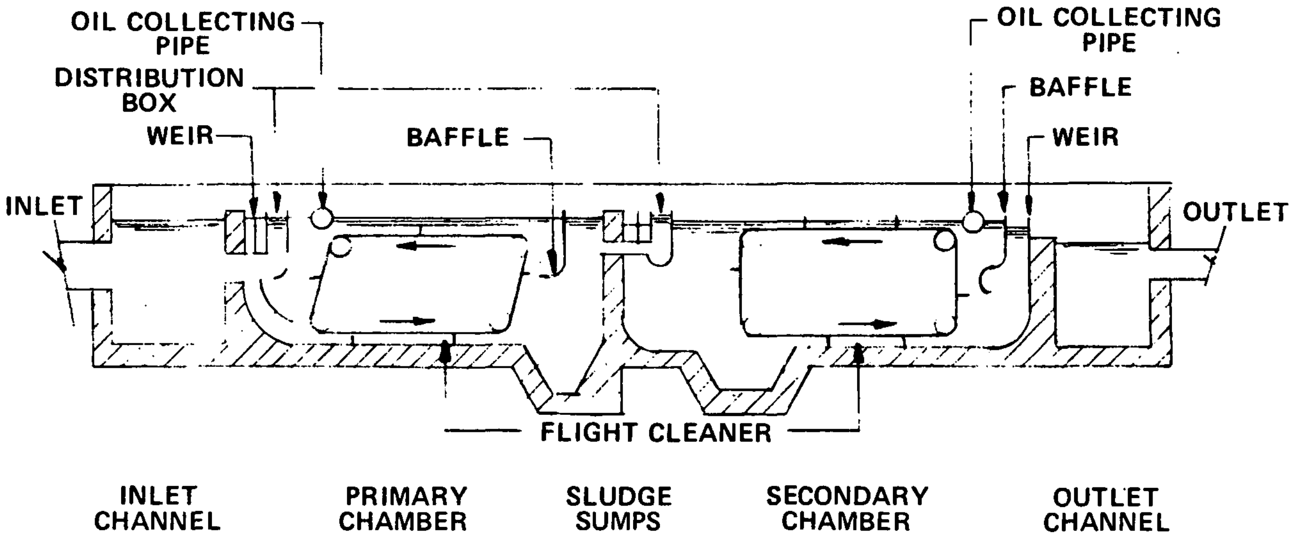
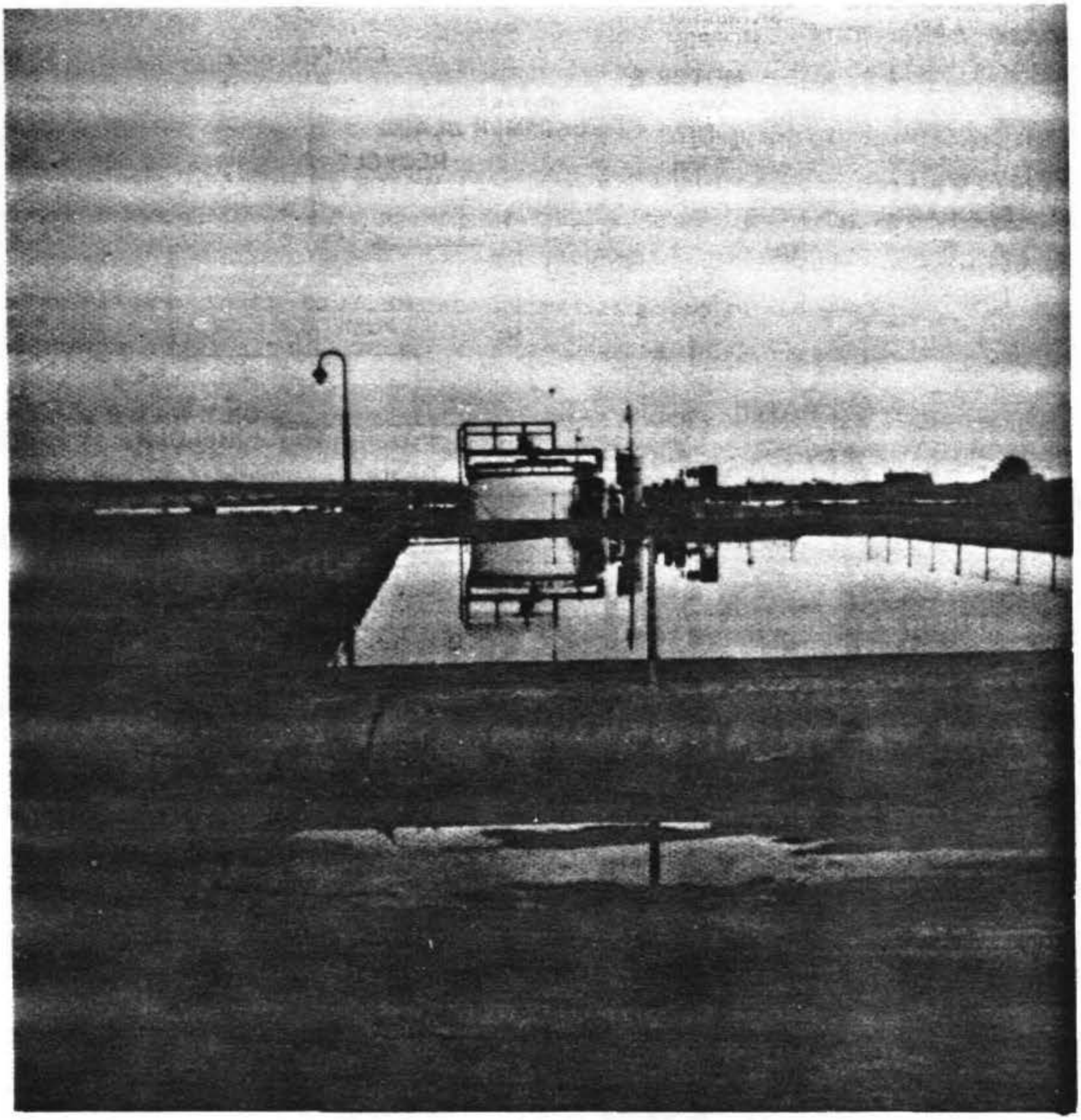


FIGURE A-VII-35 TYPICAL A. P. I. OIL-WATER SEPARATOR



OIL SEPARATOR AND AIR FLOATATION UNIT

PLANT NO. 0610

Figure A-VII-36

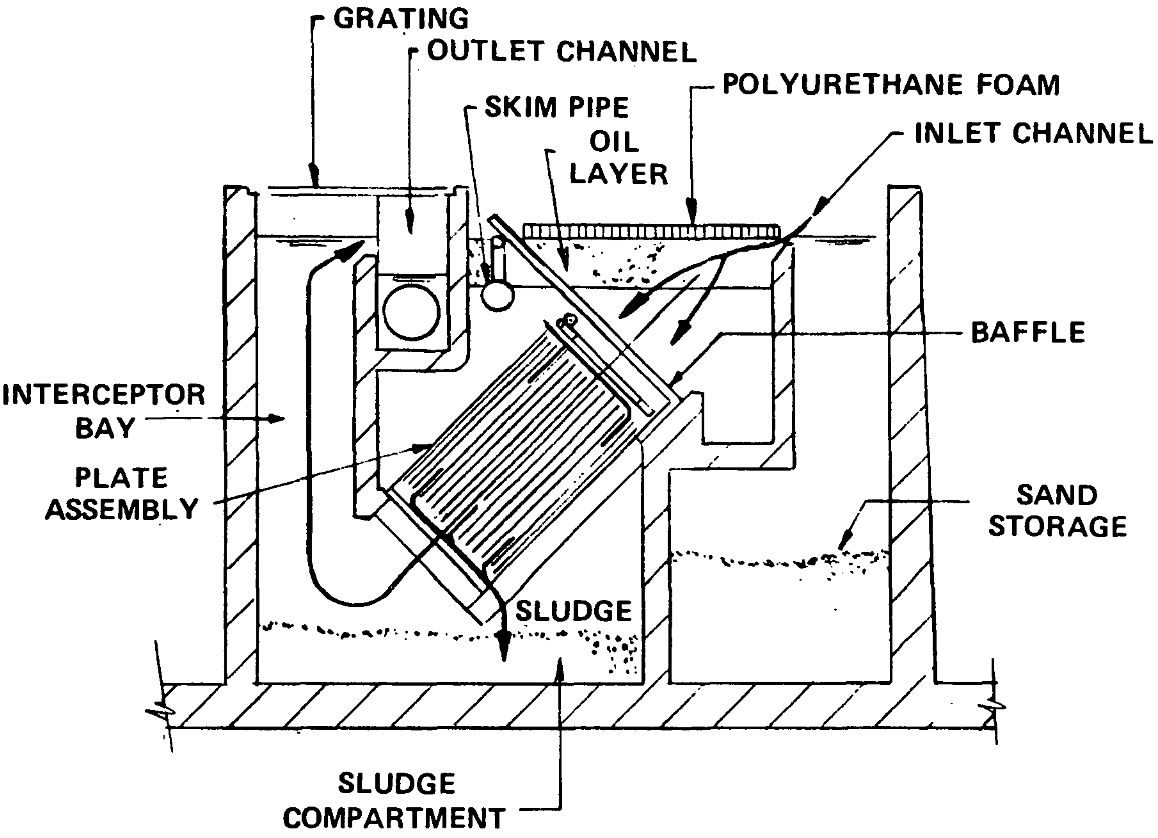


FIGURE A-VII-37 CORRUGATED PLATE TYPE OIL WATER SEPARATOR

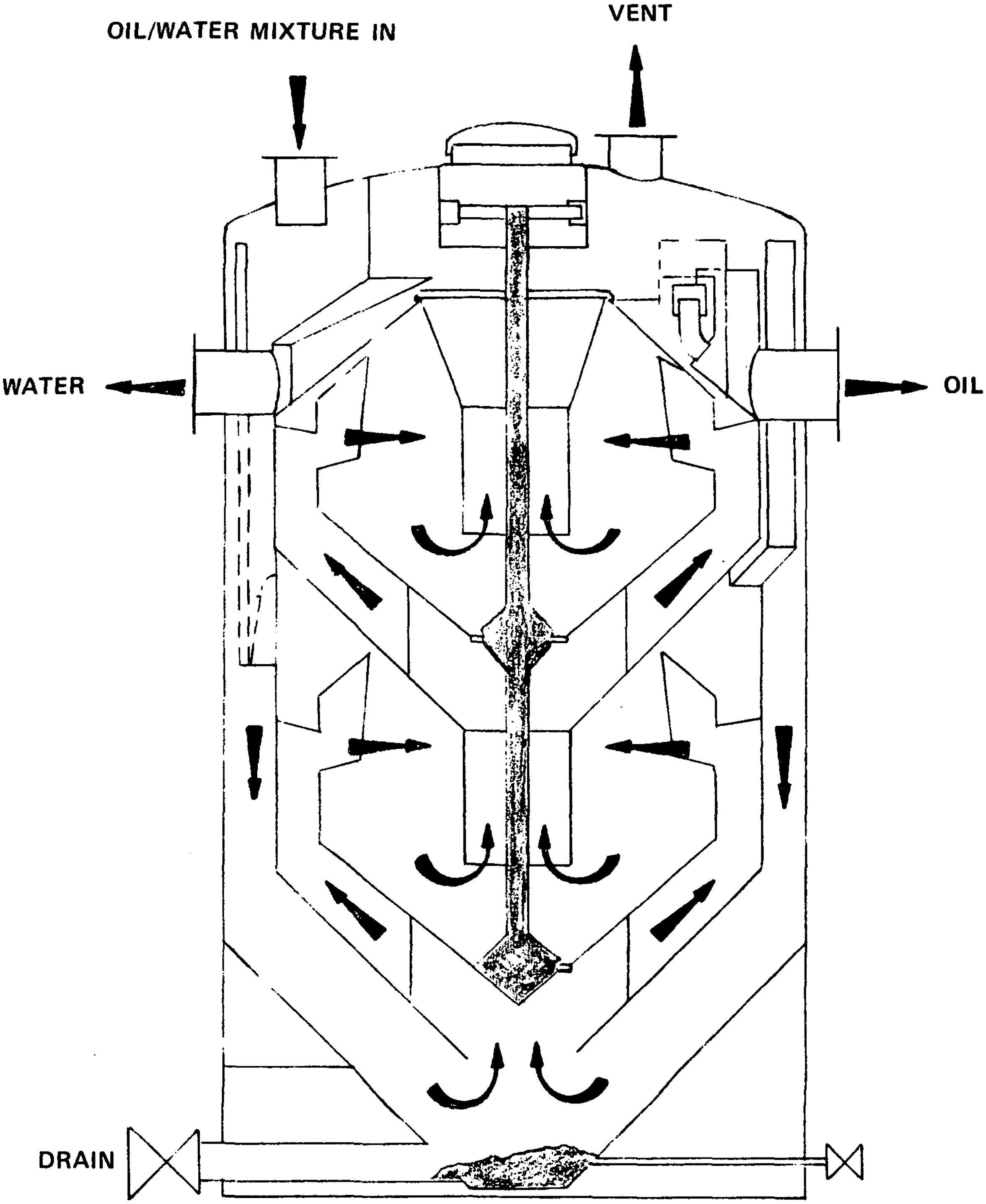


FIGURE A-VII-38 OIL WATER SEPARATOR

with the sludge removal step should be kept to a minimum to minimize make-up water requirements. This can be achieved by providing adequately sized ponds and adding flocculants for efficient settling. Use of mechanical filtration equipment will further dewater the sludge and thus minimize liquid effluent discharge. Oxidation of the scrubber discharge effluent will ensure that sulfite level in the sludge is minimal. Lime/limestone addition is necessary to eliminate acidity. If the process employs a pond in the scrubber liquor recycle loop, the pond should be lined to minimize ground seepage.

Sanitary Wastes

Sanitary wastes can be discharged to municipal sewerage systems where possible. In rural areas, packaged sewage treatment plants are commonly used for treating this waste. Most of these plants are based on the biological principle of aerobic decomposition of the organic wastes and are able to reduce the raw sewage concentrations of BOD-5 and TSS to meet effluent standards applicable to publicly-owned treatment works.

Other Wastes

Intake screen backwash can be collected, viable organisms returned to the waterway, and the collected debris removed before discharging the effluent to the receiving waters. Collected debris can be disposed of in a landfill or other solid waste disposal facility.

For other miscellaneous wastes, such as those from laboratory and sampling activities, etc., pH adjustment and TSS removal is similar to that followed in other waste streams. Technology for the control of pollution from construction activities is treated comprehensively in Reference 382.

Oil spillage from transformers can be absorbed in slag-filled pits under and around the transformers. Curbing of the pits prevents flooding by surface water and floating off the oil.

Waste water from the primary coolant loop of nuclear plants may contain boron; however, no treatment is known for boron removal. As explained in Part A Section V, nuclear plants follow a radioactive waste management system. Any treatment or recycle concept applied to remove non-radioactive pollutants from these wastes would have to consider the radioactive components of this waste.

Various Waste Streams - Concentration and Recycle

Vapor-compression evaporation systems can be used to recover and recycle water from various waste streams encountered normally in a steam electric generating plant. These streams include boiler blowdown, demineralizer blow-down, ash sluicing water blowdown, coal pile runoff, SO_2 scrubber blowdown, treated sewage effluent, boiler cleaning waste and cooling tower blowdown. Two case histories in which the vapor-compression evaporation systems (brine concentrator) have been installed in steam electric generating plants are described below.

Case I (See Figure A-VII-39 and Table A-VII-16) is an application of the brine concentrator that was placed in operation on June 14, 1974. This application will ultimately employ several brine concentrators to completely eliminate wastewater blowdown from the ash sluice system. The ash sluice water is provided by the cooling tower blowdown where it is recycled to the boiler and ash is sluiced to the ash separator. The supernatant from the ash separator is recycled to the ash sluice water storage tank for reuse. The blowdown from the ash sluice water storage tank is processed in the brine concentrator where the concentration of total solids is increased to over 100,000 ppm. It is contemplated that as additional generating units are placed on line, additional brine concentrtors will be installed so that eventually the only feed to the pond will be the waste from the brine concentrators.

Case II (See Figure A-VII-40 and Table A-VII-17) is an application of the brine concentrator that was placed in operation on June 28, 1974. This installation will eventually be used to process a blowdown from various generating plant waste streams. However, the brine concentrator is currently being utilized to concentrate only cooling tower blowdown. The blowdown will be concentrated approximately 40 times such that the feed of 156 gpm is reduced to 3.7 gpm of concentrate. At this installation, the client anticipates a wide variation in the feedwater chemistry to the brine concentrator. On the chemistry data sheet are shown the maximum TDS design conditions and the normal value TDS conditions.

Evaporation ponds are in use at a number of steam electric powerplants to reduce waste streams to dryness. Plant No. 4883 uses 101,000 sq ft of lined evaporation pond to evaporate a maximum flow of 43,000 gal/day of waste water to

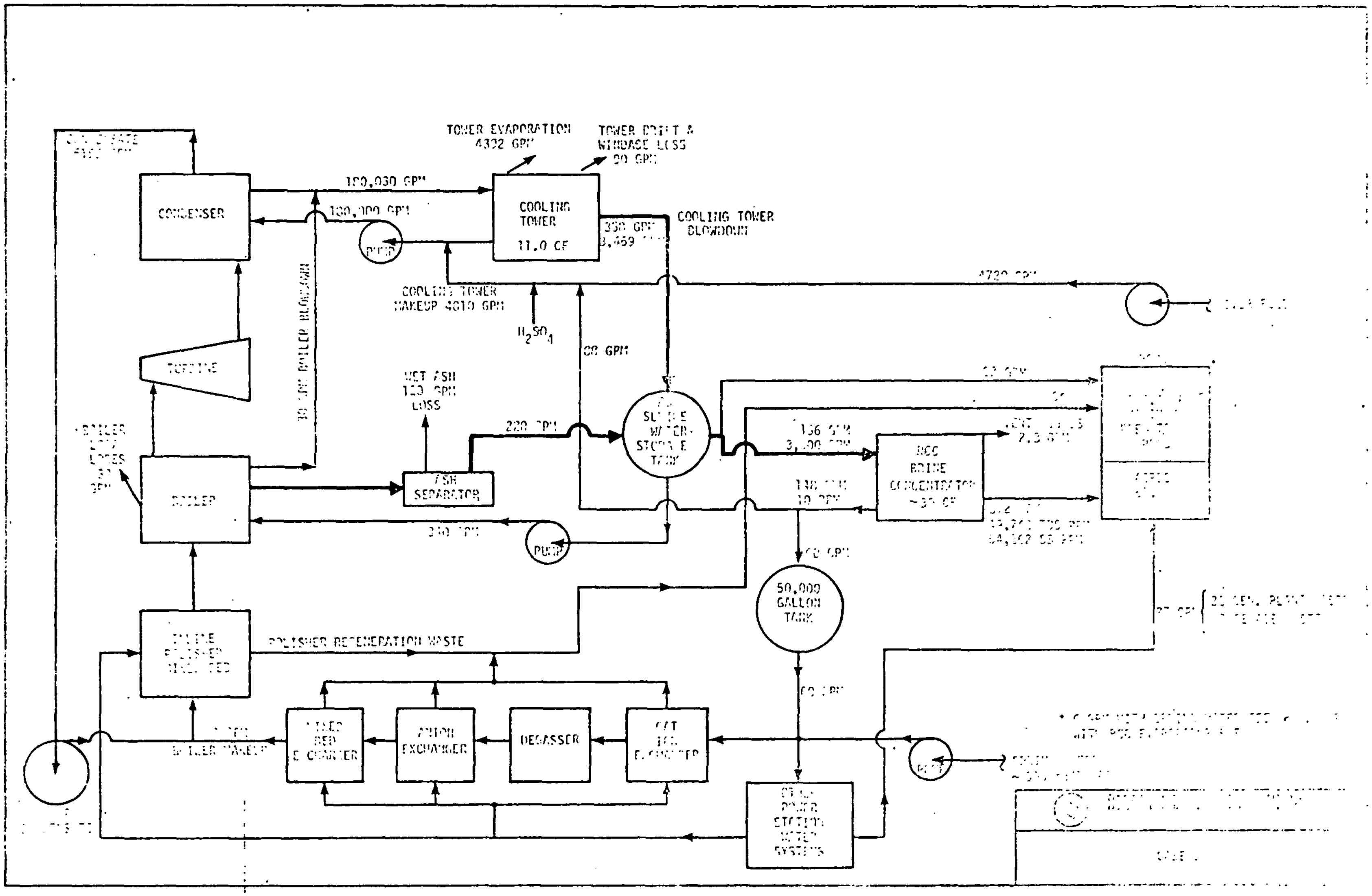


Figure A-VII-39 Vapor-Compression Evaporation System (Case I)
System commissioned on June 14, 1974

]

Table A-VII-16

RCC BRINE CONCENTRATOR SYSTEM CHEMISTRY (Case I)[452]

COMPONENT	CONCENTRATOR FEED (TDS)	CONCENTRATOR WASTE BRINE (TDS)*	PRODUCT WATER
CALCIUM (As Ca^{++})	529 PPM	520 PPM	
MAGNESIUM (As Mg^{++})	276	7,800	
SODIUM (As Na^{+})	55	2,850	
BICARBONATE (As HCO_3^-)	488	-	
SULFATE (As $SO_4^=$)	2,002	36,528	
CHLORIDE (As Cl^-)	62	1,800	
SILICA (As SiO_2)	55	250	
*30 CONCENTRATION FACTORS			
TDS (PPM)	3,467	49,748	< 10
SS (PPM)	-	54,862	-
FLOW RATE (GPM)	156	5.2	148
pH	8.0-8.5	7.0-7.6	6.0-7.0

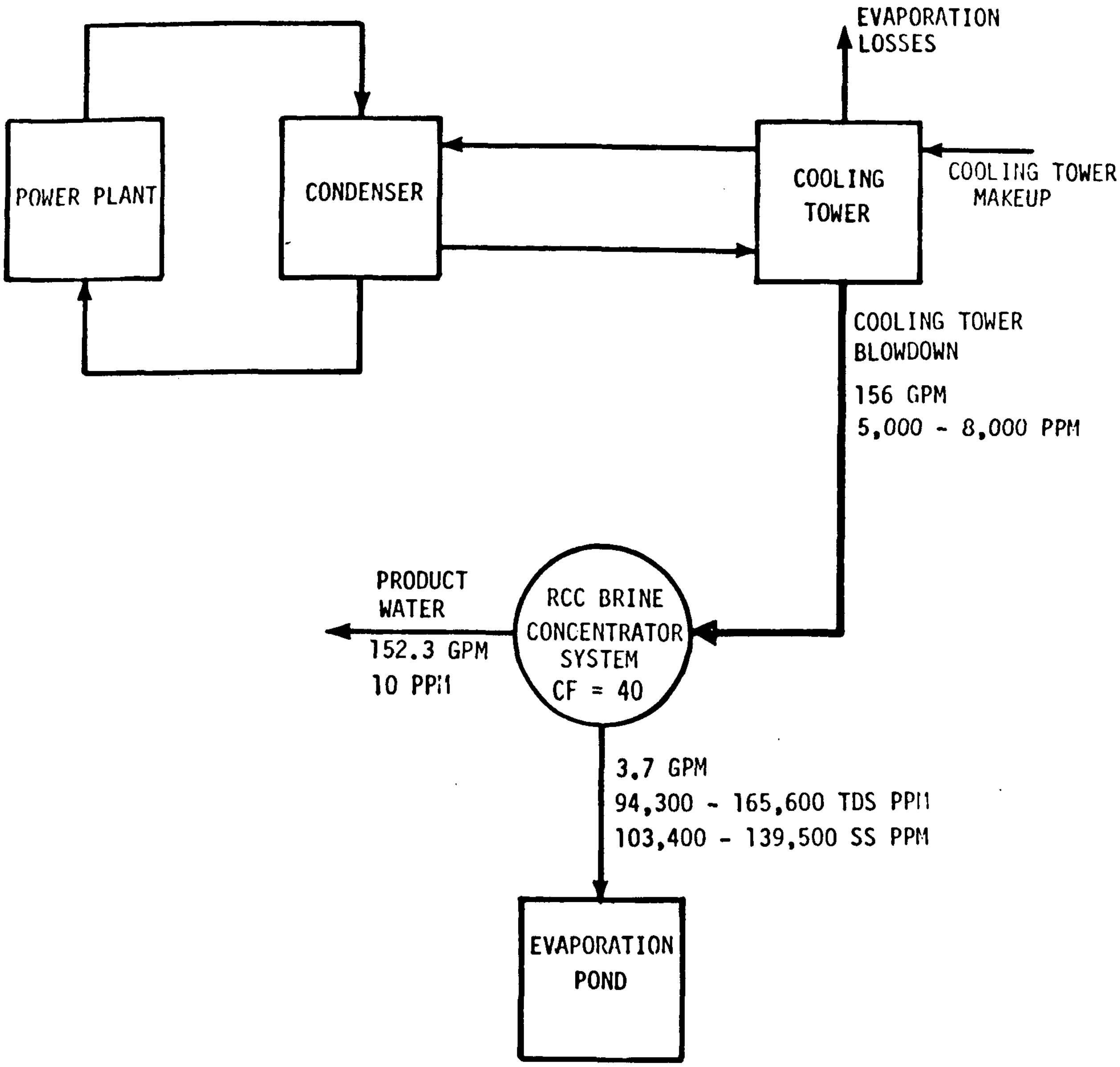


Figure A-VII-40 Vapor-Compression Evaporation System
(Case II)

452

Table A-VII-17

RCC BRINE CONCENTRATOR SYSTEM CHEMISTRY (Case II) [452]

COMPONENT	CONCENTRATOR FEED (TDS)		CONCENTRATOR WASTE BRINE (TDS)*		PRODUCT WATER
	NORMAL	HIGH	NORMAL	HIGH	
CALCIUM (As Ca^{++})	748 PPM	1,000 PPM	720 PPM	480 PPM	
MAGNESIUM (As Mg^{++})	166	149	6,640	5,960	
SODIUM (As Na^{+})	496	1,182	19,840	47,280	
BICARBONATE (As HCO_3^{-})	360	360	-	-	
SULFATE (As $SO_4^{=}$)	2,964	4,963	60,000	103,680	
CHLORIDE (As Cl^{-})	172	199	6,880	7,960	
SILICA (As SiO_2)	110	134	250	250	
*40 CONCENTRATION FACTORS					
TDS (PPM	5,016	7,987	94,330	165,610	< 10
SS (PPM)	-	-	103,430	139,470	-
FLOW RATE (GPM)	156	156	3.7	3.7	152.3
pH	8.0	8.0	7.0-7.6	7.0-7.6	6.0-7.0

dryness. Configured systems are being installed at three steam electric powerplants (plant nos. 0413, 3517 and 4907). The configured systems use brine concentrators which recycle the distillate to the demineralizer system or to the cooling tower. All process 156 gpm of cooling tower blowdown. However, water treatment wastes, etc., are combined with the recirculation cooling water. The plants involved are designed to achieve no discharge of pollutants through recycle of waste water streams. Therefore, the concentrated brine ultimately contains all plant wastes. The costs of the units are approximately $2-4/kw with about 18 months required for installation. The application of evaporative brine concentrators to low-volume waste stream effluents after chemical treatment is not known to have been achieved. Therefore, some technical risks may be involved in applying this technology directly to low-volume waste water of powerplants.

Sludge Disposal

The major solid wastes from powerplants can be classified into three categories:

1. Fuel related wastes (ash) - flyash, bottom ash and boiler slag
2. Scrubber sludges - from non-regenerable (throwaway) flue gas desulfurization systems
3. Chemical sludges - from water and effluent treatment systems

Of the three wastes, partial utilization of ash has been commonly practiced. Tables A-VII-18 and A-VII-19 indicate ash collection and utilization data (Ref. 33). Estimated 1976 ash production is also shown in Table A-VII-18. It can be seen that the largest usage has been, and continues to be, as fill material for roads, construction sites, etc. However, new commercial processes are being developed and the trend seems to be to increase ash utilization for other applications. Some recent developments which offer potential high-tonnage ash utilization are as follows: (Ref. 33).

1. A material composed of lime, flyash and sulfate or sulfite sludges was used to pave some access roads and parking areas at Dulles International Airport (Washington, D.C.) for the Transpo '72 exhibition. 2. Two cement companies announced new plants and programs to market for general construction purposes a portland pozzolan cement that is a blend of portland cement and flyash. 3. A new project in northern West Virginia will use 250,000 tons of

Table A-VII-18

Ash Collection and Utilization, 1971 (Tons) [33]

	Fly Ash	Bottom Ash	Boiler Slag
Ash uses:			
1. Mixed with raw material before forming cement clinker	104,222	–	91,975
2. Mixed with cement clinker or mixed with pozzolan cement	16,536	–	–
3. Partial replacement of cement in:			
a. Concrete products	177,166	35,377	76,563
b. Structural concrete	185,467	–	–
c. Dams and other mass concrete	71,411	–	–
4. Lightweight aggregate	178,895	13,942	–
5. Fill material for roads, construction sites, etc.	363,385	533,682	2,628,885
6. Stabilizer for road bases, parking areas, etc.	36,939	7,880	49,564
7. Filler in asphalt mix	147,655	2,833	81,700
8. Miscellaneous	98,802	475,417	428,026
Subtotal	1,380,478	1,069,131	3,356,713
Ash removed from plant site (at no cost to utility, but not covered in categories listed above, see Table II below)	1,872,728	542,895	381,775
Total ash utilized	3,253,206	1,612,026	3,738,488
Ash removed to disposal areas (at company expense)	24,497,848	8,446,941	1,232,298
Total ash collected, 1971 *	27,751,054	10,058,967	4,970,786
Estimated 1976 ash production	36,994,436	117,411,603	2,517,703

*These ash production figures are for electrical utilities, which account for 60% of the bituminous coal and 80% of the ash-producing oil that is consumed in the U.S.

Table A-VII-19

Known Uses for Ash Removed From Plant at No Cost to Utility (Tons) [33]

	Fly Ash	Bottom Ash	Boiler Slag
Cement manufacture	51,697		
Mine-fire control	129,258	38,940	
Anti-skid winter roads	82,948	178,323	166,131
Building blocks and fill material		14,741	229,393
Experimental soil conditioner	25		
Misc. fill material	477,918	34,760	
Airport pavement	16,200		
Soil stabilization	5,035		
Fertilizer filler	1,321		
Rubber filler	296		
Vanadium recovery	200	200	
Dust control		11,284	
Asphaltic wear-course aggregate			2,130
Total	764,898	278,248	397,654

bottom ash and boiler slag as aggregate for a new portion of West Virginia's Route 2. Besides conserving dwindling supplies of local natural aggregates, this use of ash is expected to save $500,000 in material costs. 4. Ontario Hydro commenced operation of its flyash processing plant at Mississauga, Ontario, to make pozzolan, aggregate, magnetite and carbon products. Also, International Brick and Tyle's flyash brick plant near Edmonton, Alta., has started production; it is designed to initially provide 6.25 million units annually to the face-brick and paving-tile market in western Canada. The process being used was developed by the Coal Research Bureau of West Virginia University. This process will also be used in Czechoslovakia in a plant that will consume about 100,000 tons/year of flyash. 5. Specifications for "lime-flyash-aggregate" base material are anticipated to become part to the Federal Aviation Administration's construction guidelines. Newark and JFK Airports have already utilized this type of material in the construction of runways for new, heavier aircraft. Similar pavements are being designed for airports at other locations.

Besides these commercial applications, extensive research is being conducted to utilize ash in agriculture as fertilizer, in brick manufacturing, for land and water reclamation, and for fire control purposes.

The traditional ash disposal methods - namely ponding and landfill - are expected to remain in widespread practice. These methods have been described in the literature (Ref. 417).

Dewatering and fixation aspects related to the disposal of scrubber sludges from non-regenerable (throwaway) flue gas desulfurization systems have been described in the literature (Ref. 417).

Chemical sludges resulting from water and effluent treatment systems in a powerplant can be disposed in landfill or ponding operations. Table A-V-20 indicates typical chemical wastes originated in a coal-fired powerplant. Based on this tabulation, it is possible to estimate the annual volume of sludges resulting from the treatment of these waste streams. For example, for a 1,000 Mw coal-fired powerplant chemical sludges will require an additional land area of approximately 2-7% for pondage. This is based on the waste characterization shown in Table A-V-20 and the following assumptions:

1. A 1,000 Mw coal-fired powerplant requires an ash disposal area of 120 acres piled to an average depth of 25 feet over a 35 year plant life and assuming an average capacity factor of 50% (Ref. 370). 2. Chemical treatment results in a precipitate of twice the weight of pollutant. 3. Suspended solids removal system is designed for an outlet concentration of 30 mg/l. 4. Chemical treatment removes all of the chemical pollutant parameters listed in Table A-V-20 completely and the weight of precipitate is twice the weight of the pollutant parameter. This is a conservative assumption. For example, if the ash pond overflow is treated only for these suspended solids removal (and no pH adjustments is required) then sulfate and hardness will not be precipitated. Consequently, the 1,000 Mw plant will require an additional land area of 2% for pondage based on these considerations.

Clarifier underflow (sludge) contains typically 1 to 2 percent solids and can be carried to a lagoon. Run-off through porous soil to ground-water can be objectionable since precipitated metal hydroxides tend to get into adjacent streams or lakes. Impervious lagoons require evaporation into the atmosphere; however, the average annual rainfall in many locations balances atmospheric evaporation. Additionally, heavy rainfalls can fill and overflow the lagoon. Lagooning can be avoided by dewatering the sludge to a semi-dry or dry condition.

Several devices are available for dewatering sludge. Rotary vacuum filters will concentrate sludge containing 4 to 8 percent solids to 20 to 25 percent solids. Since the effluent concentration of solids is generally less than 4 percent, a thickening tank is generally employed between the clarifier and the filter. The filtrate will contain more than the allowed amount of suspended solids, and must, therefore, be sent back to the clarifier.

Centrifuges will also thicken sludges to the above range of consistency and have the advantage of using less floor space. The effluent contains at least 10 percent solids and is returned to the clarifier.

Pressure filters may be used. In contrast to rotary filters and centrifuges, pressure filters will produce a filtrate with less than 3 mg/l of suspended solids. The filter cake contains approximately 20 to 25 percent solids. Pressure filters are usually designed for a filtration rate of 2.04 to 2.44 liters/min/sq m (0.05 to 0.06 gpm/sq ft) of clarifier sludge.

Solids contents from 25 to 35 percent in filter cakes can be achieved with semi-continuous tank filters rated at 10.19 to 13.44 liters/min/sq m (0.25 to 0.33 gpm/sq ft) surface. A solids content of less than 3 mg/l is normally accepted for direct effluent discharge. The units require minimum floor space.

Plate and frame presses produce filter cakes with 40 to 50 percent dry solids and a filtrate with less than 5 mg/l total suspended solids. Because automation of these presses is difficult, labor costs tend to be high. The operating costs are partially off-set by low capital equipment costs.

Automated tank-type pressure filters produce a cake the solids content of which can reach as high as 60 percent while the filtrate may have up to 5 mg/l of total suspended solids. The filtration rate is approximately 2.04 liters/min/sq m (0.05 gpm/sq ft) filter surface area. Pressure filters can also be used directly for neutralized wastes containing from 300 to 500 mg/l suspended solids at design rates of 4.88 to 6.52 liters/min/sq m (0.12 to 0.16 gpm/sq ft) and still maintain a low solids content in the filtrate. Filter cakes can easily be collected in solid waste containers and hauled to land fills.

Several companies have developed proprietary chemical fixation processes which are being used to solidify sludges prior to land disposal. In contrast to filtration, the amount of dried sludge to be hauled is increased. Claims are that the process produces insoluble metal ions so that in leaching tests only a fraction of a part per million is found in solution. However, much information is lacking on the long term behavior of the "fixed" product, and potential leachate problems which might arise. The leachate test data and historical information to date indicate that the process has been successfully applied in the disposal of polyvalent metal ions and it apparently does have advantages in producing easier to handle materials and in eliminating free water. Utilization of the chemical fixation process is felt to be an improvement over many of the environmentally unacceptable disposal methods now in common usage by industry. Nevertheless, chemically fixed wastes should be regarded as easier-to-handle equivalents of the raw wastes and the same precautions and requirements required for proper landfilling of raw waste sludges should be applied.

Powerplant Wastewater Treatment Systems

Previous sections of this report have discussed the significant parameters of chemical pollution present in various waste streams and the control and treatment technology available to reduce these parameters to acceptable limits. It would generally not be practicable for powerplants to provide separate treatment facilities for each of the waste streams described. However, segregation and treatment of boiler cleaning waste water and ion exchange water treatment waste water is practiced in a relatively few stations, but is potentially practicable for all stations. Oily waste waters are segregated from nonoily waste streams at some stations and the oil and grease removed by gravity separators and flotation units. Combined treatment of waste water streams is practiced in numerous plants. However, in most cases treatment is accomplished only to extent that self-neutralization, coprecipitation and sedimentation occur because of the joining and detention of the waste water streams. Chemicals are added during combined treatment at some plants for pH control. Most of these stations employ lagcons, or ash ponds, while a few plants employ configured settling tanks. It would be generally practicable, from the standpoint of costs versus effluent reduction benefits, for powerplants to treat separately certain low-volume waste streams, certain intermediate-volume waste streams, the high-volume waste streams, and the waste stream caused by rainfall runoff.

A major problem in providing a central treatment facility is the variability of the flow characteristics of the waste streams generated in a powerplant. As previously indicated, some of the flows are either continuous or daily batch discharges, while others only occur a few times per year and others depend on meteorological conditions. The provision of adequate storage to retain the maximum anticipated single batch discharge is therefore a critical aspect of the design of a centralized treatment facility. For purposes of this report it has been conservatively assumed that sufficient storage would be provided to store all of the batch discharges as if they would occur simultaneously and deliver them to the treatment units at an essentially uniform rate.

A small, highly efficient central treatment facility would be primarily designed to handle low volume wastes with relatively high concentrations of heavy metals, suspended solids, acidity, or alkalinity, etc. The addition of intermediate-volume wastes such as cooling tower blowdown and nonrecirculating ash sluice water to this facility would require a significantly more costly investment and would not with the same practices be able to affect as high a degree of effluent reduction (pounds) due to the dilution factors involved. The capital investment required for inclusion of cooling tower blowdown in the central facility may be significant. The benefit derived from including this stream in terms of suspended solids removal is questionable when compared to the added cost involved. Cooling tower blowdown and nonrecirculating ash sluice water was not considered in development of the model treatment facility because the characteristics of these streams are not necessarily compatible with the treatment objectives of the central facility.

Cooling tower blowdown generally can be characterized by a relatively high concentration of the total dissolved solids present in the water source and a somewhat lower concentration of the suspended solids present in the water source. In addition, tower blowdown generally contains small concentrations of chlorine and other additives from the closed cooling system. The objective of directing cooling tower blowdown to a central treatment facility would most likely be for the removal of suspended solids. However, in general treatment for removal of suspended solids prior to the use of water as make up to a cooling tower would be practiced if the suspended solids level is at all significant. In any event, some concentration of the suspended solids level will occur in the tower due to evaporation and, in some cases, due to contact with airborne particulates. However, the cooling tower basin also acts as a settling basin to some degree, so that suspended solids in many cases will settle out in the cooling tower basin. In any case, the objective of suspended solids removal from these intermediate-volume waste streams can best be achieved by the commonly employed practice of using sedimentation lagoons.

In some cases in both fossil-fueled (plant no. 2119) and nuclear plants (plant no. 3905) cooling tower blowdown is combined with low volume wastes in the sedimentation pond. Better results can be obtained by segregation of these low-volume and intermediate-volume waste streams. In plant no. 3905 the pond is designed for 24 hours detention and is divided by a dike to provide settled solids accumulation in the forepond to facilitate removal, and further to prevent short-channeling of waste water flows. Segregation could have been provided at an incremental cost for the additional piping required.

Where sufficient land is not available for effective ash ponds and/or where no discharge of heavy metals, etc., would be required, closed-loop recirculating systems can be employed which require much less available land. Recirculating ash sluicing systems of this type are capable of achieving significant removals of pollutants up to no discharge of ash in waste water effluents. An example of such a system is the upgraded waste treatment facility now operating at plant No. 3630. In this system, bottom ash is sluiced from the ash hoppers and collected in the hydrobins. The sluicing water is recirculated back to the hoppers thus making a closed loop system.

Wastewater Management

Because of the varied uses that are made of water in a powerplant and the wide range of water quality required for those uses, powerplants present unusual opportunities for wastewater management and water reuse. The highest water quality requirements are for the bciler feedwater supply. Makeup to this system must be demineralized to TDS concentrations of the order of 50 mg/l for intermediate pressure plants and 2 mg/l for high pressure plants. Boiler blowdown is generally of higher purity than the original source of supply, and can be recycled for any other use in the plant, including makeup to the demineralizers. In plants using closed cooling water systems, the blowdown from the cooling system is of the same chemical quality as the water circulating in the condenser cooling system. Limits on the water quality in that system is governed by the need to remain below concentrations at which scale forms in the condenser. However, if calcium is the limiting component, the introduction of a softening step in the blowdown stream would restore the waste to a quality suitable for reuse. Even without softening, the blowdown from the condenser cooling water system is suitable for makeup to the ash sluicing system, or for plants using alkaline scrubbers for control of sulfur dioxide in stack gases, as makeup to that system. Plants located adjacent to mines (mine-mouth plants) often have additional requirements for low quality water for ore processing at the mine.

With these cascading water uses it is frequently possible to devise water management systems in which there is no effluent as such from the powerplant. These plants still have significant overall water requirements, but the water is used consumptively for evaporation and drift in cooling towers, for sulfur dioxide removal, or for ash handling and ore preparation. Figures A-VII-41, 42 show flow diagrams, taken from Reference 378, for a typical 600 Mw coal-fired plant, with and without waste water management to achieve no discharge of pollutants. An equalization basin is usually provided for temporary large waste discharges such as result from cleaning operations, but even these wastes can be reintroduced into the system at a later time. Several

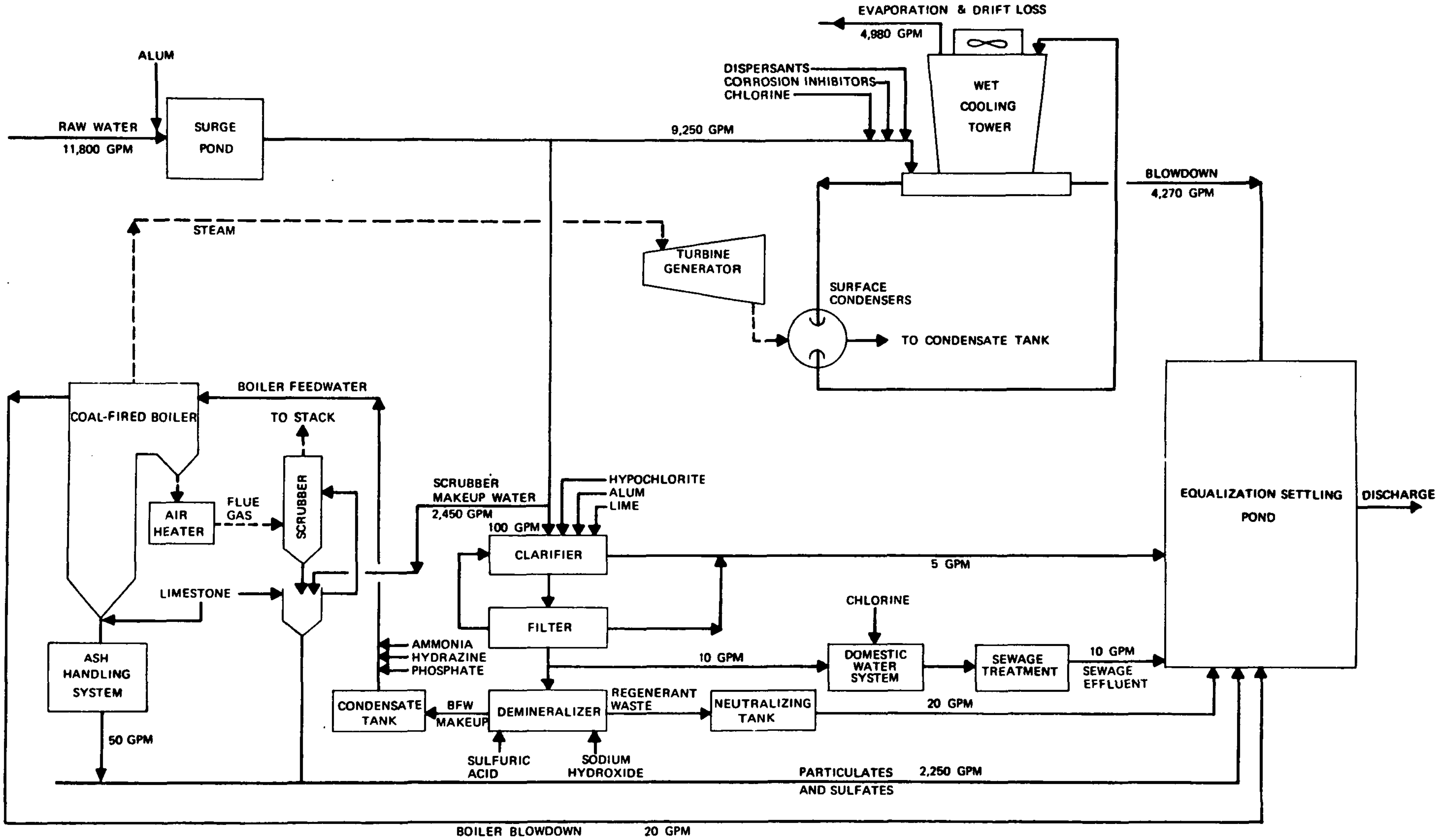


Figure A-VII-41 Sewage and Waste Water Disposal for a Typical Coal-Fired Unit, 600 Mw[378]

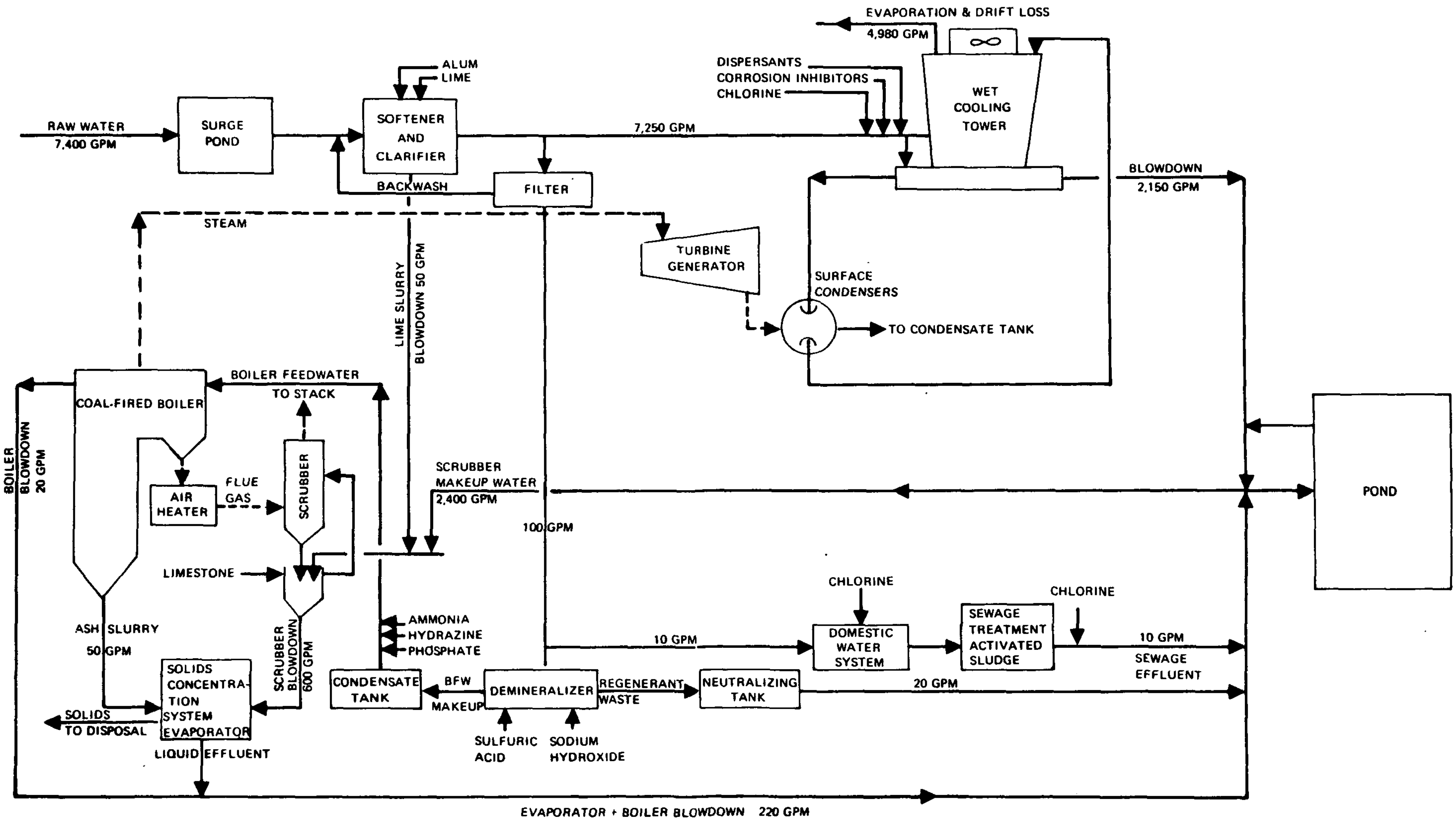


Figure A-VII-42 Recycle of Sewage and Waste Water for a Typical Coal-Fired Unit, 600 Mw[378] plants visited during this study were using water management schemes of this type without economic penalties. Water management may be the most economical mode for operating a powerplant in a water short area. There can be no doubt that the concept of no discharge of pollutants is feasible for many steam electric powerplants. A number of plants within the industry currently practice recycle and reuse in varying degrees and in a number of different ways. Several plants constructed within the last few years were designed for minimal or no discharge. See Figure A-VII-43.

Plant No. 3206 was intended to be a no discharge facility and is achieving that goal although some operating problems have been encountered. The plant receives slurried coal by pipeline and after dewatering reuses the water in its service system. Makeup to the cooling towers is softened to obtain 16-17 concentrations in the system and therby minimize blowdown. Ash sluicing water is also recycled and blowdown from this system along with other blowdown streams are sent to evaporation ponds for final disposal.

Plant No. 5305 is a mine-mouth facility which also was designed to produce no discharge other than that resulting from coal pile drainage and the effluent from the sewage treatment plant. Discharges from plant operations, including cooling tower blowdown, water treatment wastes, boiler blowdown, floor drains and blowdown from a closed ash sluicing system are collected in effluent storage ponds. Makeup to the ash sluicing operation is taken from these ponds, but the major portion of the water is transported to the mine and coal preparation plant. The plant is an excellent example of cascading water reuse to usages requiring successively lower water quality. A large amount of the water withdrawn from the river is lost through evaporation in the cooling towers. The remainder is either ultimately tied up with filter cake at the coal preparation plant or disposed of with wet ash. Both the filter cake and the ash are returned to the mine for use as fill.

Plant No. 0801 utilizes a series of ponds to achieve intermittent controlled discharge for use in irrigation. The ponds provide the water required for condenser cooling, boiler feed, flue gas scrubbing and ash sluicing. Ash sluice, boiler blowdown and scrubber wash water are discharged to two alternately used ash ponds. Overflcw from these ponds and condenser cooling water are discharged to a series of three ponds or lakes. The third in the series of ponds serves as the water source, thus providing a completely closed system.

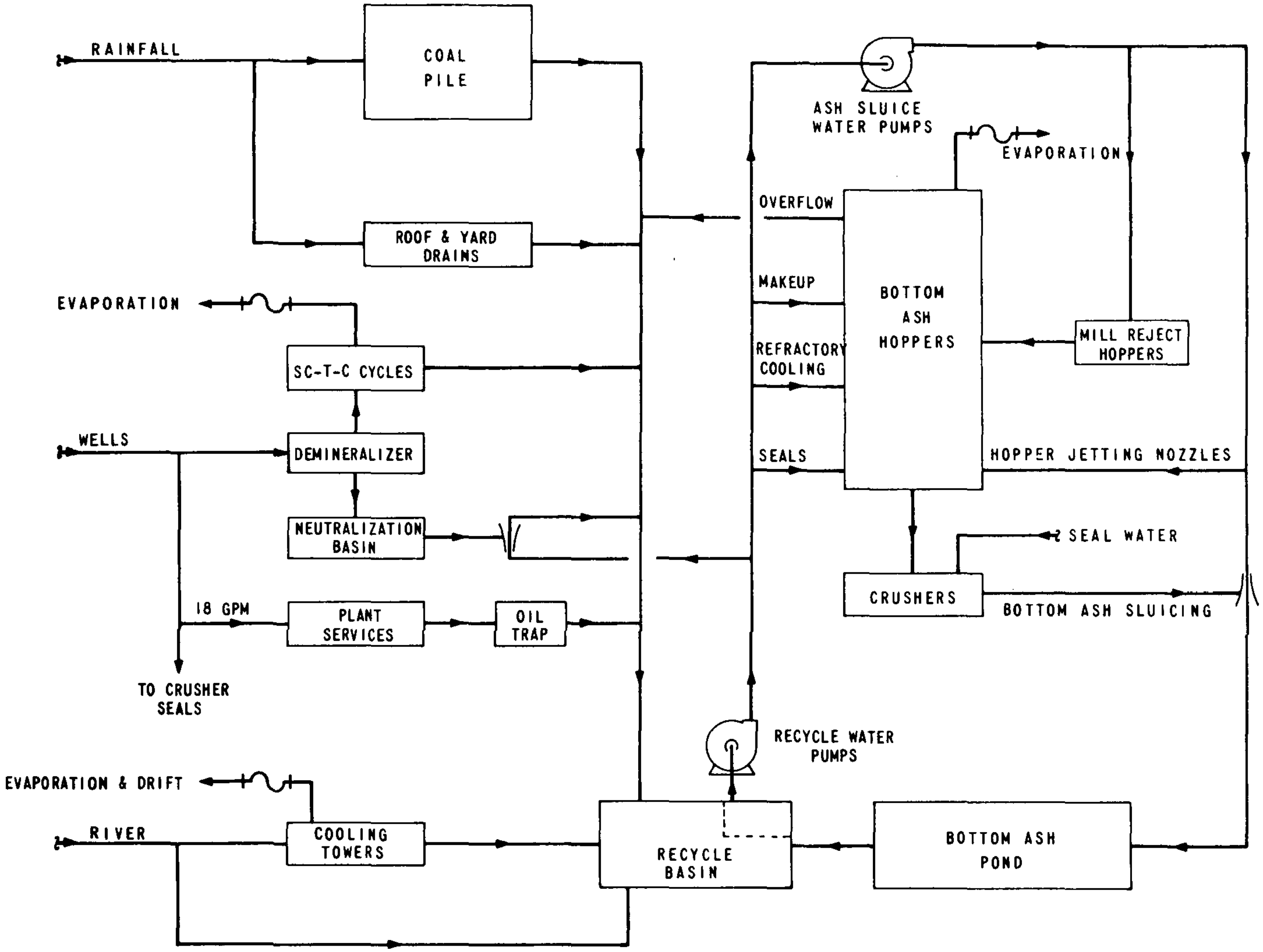


Figure A-VII-43

RECYCLE WATER SYSTEM, PLANT NO. 2750

Several generating stations are utilizing closed-loop recirculating systems for ash sluicing operations. Systems of this type are capable of achieving effluent reductions up to no discharge of pollutants in wastewater effluents. Examples of such systems include plants 3630 (a retrofit) and 3626. Both of these installations collect sluiced bottom ash in hydrobins, and recirculate the water back to the ash hoppers for sluicing. This type of system is particularly suited to plants where sufficient land is not available for effective ash ponds. Plant No. 4846 also utilizes a closed-loop ash sluicing system, but employs an ash pond with discharge from the pond being pumped back to the plant.

Plant No. 3630 has a retrofit system for achieving no discharge of pollutants from bottom ash sluicing, boiler cleaning wastes, floor drainage, boiler blowdown, evaporator blowdown, and demineralizer wastes. This is achieved through the re-use of neutralized demineralizer waste water, boiler cleaning effluents, floor drainage, boiler blowdown, and evaporation blowdown in the ash sluicing operation. Ultimate blowdown is achieved through the moisture content (15-20 percent) of the bottom ash discharged to trucks for off-site use. Fly ash, handled dry, is also trucked to off-site uses. The plant capacity is 600 Mw and operates in the base-load mode. The bottom ash recycle and handling system occupies a space approximately 200 ft square. The entire system cost about $2 million including equipment, foundations, re-piping, pumps, and instrumentation and took approximately two years to install including engineering, purchasing, delivery, and installation. The same plant retrofit a system for collecting and filtering coal-pile drainage and road and building drainage. The coal pile trench is designed to handle drainage from a "once-in-30-years" rainfall (3.9 inches). The filtering pond is 100 ft in diameter and the filter bed is sand. Trash from the bar screens of the intake is buried on-site. The demineralizer neutralization system cost about $80,000, the boiler cleaning effluent tanks about $100,000, re-piping about $250,000, and the intake screen washing system about $35,000.

Other plants employ various recycle and reuse techniques depending upon their water needs, environmental effects, plant layout, etc. Plants 2119 and 4217 utilize cooling tower blowdown as makeup to the ash sluicing system. Plant No. 3713 discharges treated chemical wastes from the ash pond into the intake to the condenser cooling water stream. Plant No. 4216 utilizes a closed-loop wet scrubbing device for air pollution control, and plant 2512 sluices fly ash from an electrostatic precipitator to a pond and reuses the water in the sluicing system.

A number of plants, including Nos. 2512, 2525, 3601A, and 4217 utilize central treatment facilities or ponds to treat chemical type wastes to acceptable levels for discharge. The effluents produced could be reused, but the availability of an adequate, cheap water supply has not made this necessary in these instances.

Recycling in nuclear plants and plants with no ash sluicing will depend primarily upon treatment of cooling tower blowdown and re-use of the blowdown as make up to the tower. The wastes resulting from water treatment could be recycled to the influent of the water treatment plant. Blowdown from these internal recycling schemes would be treated by desalination techniques to remove total dissolved solids, and as a result, water produced by this treatment could also be recycled. In plants where a water surplus would occur, the intent would be complete treatment for removal of all pollutants and discharge of clean water to the receiving stream. This interpretation of "no discharge" is meant to be no discharge of pollutants, rather than no discharge of any liquid stream. Generally, however, it is anticipated that even nuclear plants and plants with no ash sluicing would not have a water surplus, but would require makeup to the various internal recycling schemes.

In any case the degree of practicability of recycle and re-use systems would be favored in cases where; a) Tower construction is corrosion resistant to water high in TDS, sulfates and chlorides. b) Piping systems and equipment are lined or resistant to corrosion. c) Condenser leakage affecting feedwater quality for sustained power operation is minimized or compensated for. d) Sludge handling and disposal facilities are adequately designed and available. e) Designs for tower operation at a high number of cycles of concentration could be feasible if windage and drift losses are minimized to eliminate heavy carryover of solids to the surrounding areas.

The extent to which wastewater management can be practiced depends on the chemical constituents of the original water supply. Table A-V-2 , adapted from an unpublished paper by G.R. Nelson, shows the typical raw water characteristics of a water supply for powerplant water systems. A water supply falling within the range of concentrations shown on Table A-V-2 could probably be used for a once-through cooling system without treatment. However, if this source of supply were used for recirculating cooling, certain constituents might limit the number of cycles of concentration possible without precipitation and resultant loss of heat transfer capacity. Since the number of cycles of concentration determines the quantity of circulating water that can be maintained with a given quantity of makeup, it is generally desirable to achieve the largest number of cycles possible for any given raw water analysis. The factors limiting the number of cycles are shown in Table A-V-1.

If the number of cycles of concentration limited by the hardness of the water supply, the plant has several options to increase the number of cycles and thereby reduce both the makeup and discharge water quantitites. These include:

1. Makeup water treatment programs (makeup programs) - where all or a portion of the makeup is treated prior to entering the system. The treatment results in a net reduction in the makeup and discharge water quantities.

2. Recirculating water treatment programs (recirculating programs) where all or a portion of the recirculating water is treated and recycled back to the cooling system. The treatment results in a net reduction in the makeup and discharge water quantitities.

3. Blowdown water treatment programs (blowdown programs) - where all or a portion of the blowdown is treated and recycled back to the cooling system. Again, the net result is a reduction in the makeup and discharge water quantities.

In summary, the concept of recyle or re-use is not new to the steam electric powerplant industry. Many plants utilize a variety of recycle schemes to satisfy particular needs, and these systems have the potential for broad application in the industry to meet effluent limitations guidelines.

Effluent Reduction Benefits of Waste Water Treatment to Remove Chemical Pollutants

The use of a conventional ash pond at a 1,000 megawatt coal-fired plant (capacity factor = 0.6) typically achieves the removal of over 1,200,000 lb/day of total suspended solids, with an overflow of 1,400 lb/day of total suspended solids. This is based on 1970 data for the Bull Run plant of T.V.A.[279] and an assumed 11% of ash solids in coal. It is estimated that about 70-75 percent of the U.S. coal-fired generating capacity uses ash ponds, as indicated by the data sample summarized in Table A-VII-20. For a pulverized coal burner about 75% of the ash generated is fly ash. However, the overflow discharge of total suspended solids from

Table A-VII-20

Extent of Present Use of Chemical Waste Disposal Methods in Coal-Fired Powerplants [467] (1973)

Method of Disposal	Number of Plants, %	Generating Capacity of Plants, %
Ash Ponds	61	72
Direct to Receiving Waters	24	26
Sewers	15	2

combined ash ponds would most likely be mainly the fines from fly ash, which are the most difficult to remove in ash ponds. Therefore, the use of dry fly ash sluicing in place of ash ponds would remove an increment of about 1,400 lb/day of total suspended solids that would otherwise be discharged from the ash pond. In addition to removal of total suspended solids the dry fly ash system would have the further benefit of removing aluminum, chromium, copper, iron, manganese, mercury, nickel, selenium, zinc, and other pollutant parameters that might otherwise be discharged.

Recognizing that the removal of suspended solids by sedimentation is limited by the effluent concentrations that are achievable, reduction in pond overflow discharge (at the same effluent concentration) would proportionally reduce the discharge of suspended solids in the overflow discharge. Recirculating bottom ash sluicing systems, by reducing the waste water discharge from sedimentation facilities such as ash ponds, therby result in the reduction of bottom ash total suspended solids in the discharge. In some cases, where both bottom ash and fly ash are settled in the same ash pond and water is recirculated for bottom ash sluicing, further clarification treatment of the final combined overflow from the pond to achieve effluent limitations based as a model on separate ash ponds, would result in suspended solids removals comparable to these attained by separate recirculating bottom ash systems.

Chemical treatment of metal equipment cleaning waste waters would result in significant removals of copper, iron, and other metals. Average concentrations of copper and iron in boiler tube cleaning waste water, where these data were available and where chemical treatment would be needed to achieve effluent concentrations of 1 mg/l each for copper and iron were as follows: 206 mg/l copper and 1,286 mg/l iron. Chemical treatment to achieve the above effluent limitations would remove virtually of the copper and iron in the untreated boiler tube cleaning waste water, in these cases.

In 14 cases where data on cooling tower blowdown were available, chemical treatment for chromium, phosphorus, and zinc removal would not be required in all but 2 cases. In one case, a zinc concentration of 3 mg/l was reported and a phosphorus (as P) concentration of 17.7 mg/l was reported. This is reflective of the general adequacy of simple pH adjustment rather than the use of corrosion inhibitors to control corrosion rate below 3 mils per year. Generally corrosion inhibitors would be needed only for cooling tower service with high chloride concentrations in the recirculating water.[389],[444]. In cases where chemical addition of chromium, phosphorus, or zinc would be employed for corrosion inhibition, typical maximum concentrations in cooling tower blowdown would be as follows:

30 mg/l $CrO_{\underline{4}}$
15 mg/l Zn
30 mg/l $PO_{\underline{4}}$

Substantial reduction in the discharge of these pollutant parameters would be obtained in cases where effluent treatment were needed.

Effluent reduction benefits of the control of free available chlorine and total residual chlorine in cooling water would be significant due to the large volume of cooling water used by this industry, about 40 trillion gallons per year which is roughly 10 percent of the total flow of water in U.S. rivers and streams per year, [443] and because of the widespread use of chlorine addition to cooling water (24,642 tons in 1970[233]) used by this industry.

Summary

Table A-VII-21 provides a summary of the control and treatment technology for the various waste streams. The table includes the effluent reduction achievable with each alternative, the usage in the steam electric powerplant industry and approximately capital and operating costs. Table A-VII-22 summarizes flow data for chemical wastes, indicating the range of values from reported data and typical flows or volumes for each chemical waste stream.

The costs of the application of various control and treatment technologies in relation to the effluent reduction benefits to be achieved are given in Table A-VII-23 for large volume waste streams, Table A-VII-24 for intermediate volume waste streams, Table A-VII-25 for low volume waste streams, and Table A-VII-26 for rainfall waste streams.

TABLE A-VII-21

CHEMICAL WASTES

CONTROL & TREATMENT TECHNOLOGY

Pollutant Parameter	Control and/or Treatment Technology	Effluent Reduction Achievable	Industry Usage	Costs	
				Capital	Operating
Common:					
pH	Neutralization with chemicals	Neutral pH	Common	$10-20,000 (tanks, feeder, etc.)	$3-30,000 (Chemicals, labor, etc.)
Dissolved Solids	1. Concentration and evaporation	Complete Removal	Not generally in use - Desalinization technology	$250,000-$1,660,000 from Table A-VIII-5; costs are significantly less in areas where evaporation ponds are feasible.	$150,000-$450,000 from Table A-VIII-6; costs are significantly less in areas where evaporation ponds are feasible.
	2. Reverse Osmosis	50-95%	Not in use - Desalinization technology.	50-80 ¢/1000 gal. total cost.	
	3. Distillation	60-90%	Not in use - Desalinization technology.	80-150 ¢/1000 gal. total cost.	
Suspended Solids	1. Sedimentation	90-95%	Extensive	$1000-$20,000 / Mw based on 500 gpd/Mw	1-20¢/1000 gallons
	2. Chemical Coagulation and Precipitation	95-99%	Moderate	$10,000-$35,000 / Mw based on 500 gpd /Mw	1-20¢/1000 gallons
	3. Filtration	95%	Not generally practiced-water treatment technology.	$7,000-$30,000 / Mw based on 500 gpd / Mw	1-20¢/1000 gallons
Specific:					
Phosphate (Blowdown, Chemical Cleaning, Floor & Yard Drains, Plant Laboratory & Sampling)	1. Chemical coagulation and Precipitation		Not generally practiced-water treatment technology.	$10,000-$35,000 / Mw based on 500 gpd /Mw	1-20¢/1000 gallons
	2. Deep Well Disposal	Ultimate Disposal	Not practiced	Costs extremely variable-dependent primarily on geologic conditions.	
Iron (Water Treatment, Chemical Cleaning Coal Ash Handling, Coal Pile Drainage)	1. Oxidation, chemical coagulation & precipitation	Removal to 0.1 mg/l	Limited usage	$150-4,000x10^3	10-100¢/1000 gal.
	2. Deep Well Disposal	-----------------As described above---			
Copper (Once-through Condenser Cooling)	1. Replace condenser tubes with stainless steel or Titanium.	Elimination of discharge.	Done in several plants where tubes have erroded or corroded-not done for environmental reasons.	Prohibitively expensive-would not be done except where retubing is required for process reasons.	No incremental operating cost.
Copper (Blowdown, Chemical Cleaning)	1. Chemical Coagulation and Precipitation	Removal to 0.1 mg/l	Limited usage	$100-$9,000/1000 gpd capacity	10-350¢/1000 gal.
	2. Ion Exchange	Removal to 0.1 mg/l	Not Practiced	$400-$1200/1000 gpd capacity	31-81¢/1000 gal.
	3. Deep Well Disposal	-----------------As described above---			
Mercury (Coal Ash Handling & Coal Pile Drainage)	1. Reduction & Precipitation	Removal to 0.3 mg/l	Limited usage	$700/1000 gpd	7¢-27¢/1000 gal.
	2. Ion Exchange	Removal to 0.1 mg/l	Not practiced	$18,000-$22,000/ 1000 gpd	$1/1000 gal.
	3. Adsorption	Removal to 50 μg/l	Not practiced	$5000-$50,000/ 1000 gpd	$0.50-$2/lb. mercury removed
Vanadium (Chemical Cleaning)	1. H_2S Treatment & Precipitation	Removal of low concentrations difficult to achieve	Not practiced	Cost Data Not Available	
	2. Ion Exchange		Not practiced	Cost Data Not Available	
Vanadium (Oil Ash Handling)	1. Convert to Dry Collection	Ultimate Disposal	Practiced in several plants	Cost Data Not Available	
	2. Total Recycle with Blowdown & Precipitation	Complete recycle of liquid	Not generally practiced	Cost Data Not Available	

Table A-VII-21
CHEMICAL WASTES
CONTROL & TREATMENT TECHNOLOGY (continued)

Pollutant Parameter	Control and/or Treatment Technology	Effluent Reduction Achievable	Industry Usage	Costs	
				Capital	Operating
Chlorine (Once-through Condenser Cooling)	1. Control of Residual Cl_2 with automatic instrumentation	Control to 0.2 mg/l	Limited usage in the industry-Technology from sewage treatment practiced in some plants-all systems are not capable of being converted to mechanical cleaning.	$5,000	Negligible
	2. Utilize mechanical cleaning	Eliminates Cl_2 discharge		No Cost Data Available	
Chlorine (Recirculating)	1. Control of Residual Cl_2 with automatic instrumentation	As described above			
	2. Reduction of Cl_2 with sodium bisulfite	Below detectable limits	Being installed in a new nuclear facility;however excess $NaHSO_3$ is discharged.	No Cost Data Available	
Aluminum/Zinc (Water Treatment, Chemical Cleaning, Coal Ash Handling, Coal Pile Drainage)	1. Chemical Precipitation	Removal to 1.0 mg/l	Limited usage	$500-$3000/1000 gpd	10-180¢/1000 gal.
	2. Ion Exchange	Similar to Copper			
	3. Deep Well Disposal	As described above			
Oil (Chemical Cleaning, Ash Handling, Floor & Yard Drains)	1. Oil-water Separator (Sedimentation with skimming)	Removal to 15 mg/l	Common usage	$1,500-$15,000 based on 500 gal/Mw 25-400 Mw range	No data
	2. Air Flotation	Removal to 10 mg/l	Limited usage	$5,000-$50,000	No data
Phenols (Ash Handling, Coal Pile Drainage, Floor & Yard Drains)	1. Biological Treatment	Removal to 1 mg/l	Not practiced in the industry.	$150-$2800/1000 gpd	22¢/1000 gal.
	2. Ozone Treatment	Removal to < 0.01 mg/l	Not practiced in the industry.	No data	No data
	3. Activated Carbon	Removal to < 0.01 mg/l	Not practiced in the industry.	$50-$350/1000 gpd	4¢-15¢/1000 gal.
Sulfate/Sulfite (Water Treatment, Chemical Cleaning, Ash Handling, Coal Pile Drainage, SO_2 Removal)	Ion Exchange (Sulfate) Oxidation & Ion Exchange (Sulfite)	75-95%	Not practiced in the industry.	Total cost of $2.00/1000 gal.	
Ammonia (Water Treatment, Blowdown, Chemical Cleaning, Closed Cooling Water Systems)	1. Stripping	50-90%	Not practiced; several installations in sewage treatment	Total cost - 3¢/1000 gal.	
	2. Biological Nitrification	Removal to 2 mg/l	Not practiced for these waste streams	No Data Available	
	3. Ion Exchange	80-95%	Not practiced	Total cost - 10¢/1000 gal.	
Oxidizing Agents (Chemical Cleaning)	Neutralization with reducing agent and precipitation where necessary.	Neutral pH & > 95% removal	Limited usage	No Data Available	
BOD/COD (Sanitary Wastes)	Biological Treatment	85-95%	Common practice	$25,000-$35,000	Negligible
COD (Water Treatment, Chemical Cleaning)	1. Chemical Oxidation	85-95%	Limited usage	No Data Available	
	2. Aeration	85-95%	Not practiced	No Data Available	
	3. Biological Treat.	85-95%	Not practiced	No Data Available	
Fluoride (Chemical Cleaning)	Chemical Precipitation	Removal to 1 mg/l	Limited usage	Total cost - 10-50¢/1000 gal.	
Boron (Low Level Radwastes)	Ion Exchange	Removal to 1 mg/l	Not generally practiced-radioactive material would concentrate on ion exchange resin requiring inclusion in solid radwaste disposal system.	No Data Available	

TABLE A-VII-22

FLOW RATES-CHEMICAL WASTES

Waste Stream	Reported Data Waste Flow or Volume	Frequency	Typical Flow or Volume	Basis	Remarks
Condenser Cooling Water					
Once-Through	-	-	500-1500 GPM/Mw	-	Flow reported in FPC Form 67.
Recirculating	20-7200 x 10^3 GPD	-	Varies from 0.3% to 4% of curculating water flow.		Blowdown depends on water quality and varies from 2-20 concentrations.
Water Treatment					
Clarification	No Discharge				
Softening	No Discharge				
Ion Exchange	1-533,00 x 10^3 GPD	52-365 cycles/yr.	-	-	Extremely variable-depending on raw water quality.
Evaporator	0.1-1060 x 10^3 GPD	300-365 cycles/yr.	-	-	Extremely variable-depending on raw water quality.
Boiler Blowdown	0.05-1120 x 10^3 GPD	25-365 cycles/yr.	-	-	Flow reported in FPC Form 67.
Chemical Cleaning					
Boiler Tubes	3-5 Boiler Volumes	once/7 mos.-once/100 mos.	1 boiler vol.per 1-2 hrs.-Boiler draindown time.	Frequency-once per 24-30 mos.	
Boiler Fireside	24-720 x 10^3 GAL.	2-8/yr.	300,000 GAL.	5/yr.	
Air Preheater	43-600 x 10^3 GAL.	4-12/yr.	200,000 GAL.	6-12/yr.	
Misc. Small Equip.	No reported data	-	-	-	
Stack	No reported data	-	-	-	Cleaned infrequently
Cooling Tower Basin	No reported data	-	-	-	Cleaned infrequently
Ash Handling	5-32,000 x 10^3 GPD	-	-	-	Overflow from ash ponds reported in FPC Form 67.
Drainage					
Coal pile	17-27 x 10^6 GAL/YR.	Dependent on rainfall	-	Reported data based on 43-60 inches of rain year.	Flow dependent upon frequency, duration and intensity of rainfall
Floor & Yard Drains	No reported data	-	-	-	Flow dependent upon frequency & duration of cleaning and stormwater runoff.
Air Pollution Control Devices	No Discharge				
Misc. Waste Streams					
Sanitary Wastes	No reported data	-	25-35 gal/capita/day	Personnel: operators-1 per 20-40 Mw maintenance-1 per 10-15 Mw administrative-1 per 15-25 Mw	
Plant Laboratory and Sampling	No reported data	-	-	-	Nominal, variable flow
Intake Screen Backwash	No reported data	-	-	-	Guideline requires collection & removal of debris-flow data not significant.
Closed Cooling Systems	No reported data	-	5 gal./day	-	-
Low Level Rad Wastes	No reported data	-	-	-	Flow extremely variable depending on treatment techniques, leakage, etc.
Construction Activity	No reported data	-	-	-	Flow depends primarily on rainfall.

Table A-VII-23
COSTS/EFFLUENT REDUCTION BENEFITS
CONTROL AND TREATMENT TECHNOLOGY FOR POLLUTANTS OTHER THAN HEAT
HIGH VOLUME WASTE STREAMS-

Waste Stream: Nonrecirculating main condenser cooling water

Pollutant / Technology	Cost / Effluent Reduction Benefit, [mill/kwh / [mg/l]$_{\text{effluent concentration}}$
Chlorine-free available	
Uncontrolled addition(S)	Base
Controlled addition(S) less than	0.01/2
Shutdown mechanical cleaning(S)	0.01/approaching 0
On-line mechanical cleaning (S)	0.01/approaching 0 for existing units less than 0.01/approaching 0 for new units
Chemical addition treatment*(N)	Prohibitive
Alternative biocide use*(N)	Unknown
Copper	
Present system(C)	Base
Alternative condenser tube material(S)*	Prohibitive for existing units 0.01/0 for new units
One-stage chemical treatment(N)	Prohibitive

Meaning of Symbols

C = commonly employed
CT = currently transferrable
PT = potentially transferrable
N = not known to be practiced
S = some usage
* = may substitute one pollutant for another

Table A-VII-24
COSTS/EFFLUENT REDUCTION BENEFITS
CONTROL AND TREATMENT TECHNOLOGY FOR POLLUTANTS OTHER THAN HEAT
-INTERMEDIATE VOLUME WASTE STREAMS-

Waste Streams: Blowdown from recirculating main condenser cooling water systems
Nonrecirculating ash sluicing water
Nonrecirculating wet-scrubber air pollution control systems
Nonrecirculating house service water

Pollutant / Technology	Cost / Effluent Reduction Benefit, [mill/kwh] / [mg/l]effluent concentration
Chlorine-free available	
Uncontrolled addition(S)	Base
Controlled addition(S)	less than 0.01/2
Shutdown mechanical cleaning(S)	0.01/approaching 0
On-line mechanical cleaning(S)	0.01/approaching 0 for existing units less than 0.01/approaching 0 for new units
Chemical addition treatment*(S)	0.01/approaching 0
Alternative biocide use*(N)	Unknown
Copper-total	
Present system(C)	Base
Alternative condenser tube material(S)*	Prohibitive for existing units 0.01/0 for new units
One-stage chemical treatment(N)	0.03/1
Chemical Additives	
Uncontrolled addition(S)	Base
Controlled addition(S)	Better than base
Chemical substitution*(S)	Unknown
Design for corrosion protection(C)	Costly for existing closed cooling systems less than 0.01/approaching 0 for new systems
Mercury-total	
Present system(C)	Base
One-stage chemical treatment(CT)	Unknown/0.3
Fuel substitution(N)	Unknown
Oil and Grease	
Present system(C)	Base
One-stage separation(S)	0.01/10
Two-stage separation(CT)	0.02/8
Total Phosphorus (as P)	
Present system (S)	Base
One-stage chemical treatment(CT)	0.03/5
Chemical treatment with filtration(CT)	0.05/less than 5
Chemical substitution (PT)	Unknown
pH Value	
Present system(C)	Base
Coneutralization(C)	less than 0.01
Chemical addition (S)	less than 0.01
Total Suspended Solids	
Present system(C)	Base
Conventional solids separation(C)	0.01/15
Fine solids separation(CT)	Prohibitive
Dry ash handling system(S)	0.01/sign. red.
Total Dissolved Solids	
Present system(N)	Base
Brine concentration(CT)	Prohibitive
Chromium-total	
Present system (S)	Base
Chemical treatment (CT)	($1/1000 gal)/0.2
Chemical substitution (PT)	Unknown
Zinc-total	
Present system (S)	Base
Chemical treatment (CT)	0.05/1
Chemical substitution (PT)	Unknown

Meaning of Symbols

C = commonly employed
CT = currently transferrable
PT = potentially transferrable
N = not known to be practiced
S = some usage
* = may substitute one pollutant for another

Table A-VII- 25
COSTS/EFFLUENT REDUCTION BENEFITS
CONTROL AND TREATMENT TECHNOLOGY FOR POLLUTANTS OTHER THAN HEAT
-LOW VOLUME WASTE STREAMS-

Waste Streams:	
	Blowdown from recirculating ash-sluicing systems
	Blowdown form recirculating wet-scrubber air pollution control systems
	Boiler blowdown
	Cooling tower basin cleanings
	Floor drainage
	Intake screen backwash
	Laboratory and sampling streams
	Low-level radwastes*
	Miscellaneous equipment cleaning
	- Air preheater
	- Boiler fireside
	- Boiler tubes
	- Small equipment
	- Stack, etc.
	Sanitary system
	Service and small cooling water systems blowdown, etc.
	Water treatment

Technology / Pollutant	Cost / Effluent Reduction Benefit, [mill/kwh] , $[mg/l]_{\text{effluent concentration}}$
Present System(C)	Base
One-Stage Chemical Treatment(S)	0.05 mill/kwh
Copper-total	10 mg/l
Iron-total	10 mg/l
Heavy metals in general	10 mg/l
Oil and grease	10 mg/l
pH value	6.0 to 9.0
Total Suspended Solids	15 mg/l
Numerous misc. parameters	significant reductions
Two-Stage Chemical Treatment(CT)	0.1 mill/kwh
Chromium-total	0.2 mg/l
Copper-total	1 mg/l
Iron-total	1 mg/l
Heavy metals in general	1 mg/l
Oil and grease	< 10 mg/l
pH value	6.0 to 9.0
Total suspended solids	15 mg/l
Numerous misc. parameters	significant reductions
Brine Concentration and Recycle(PT)	0.5 mill/kwh
All parameters	no discharge
Biological Treatment(C)	0.01 mill/kwh
BOD, etc.	municipal stds.

Meaning of Symbols
C = commonly employed
CT = currently transferrable
PT = potentially transferrable
N = not known to be practiced
S = some usage
* = no applicable technology due to possible radiation hazards

Table A-VII- 26
COSTS/EFFLUENT REDUCTION BENEFITS
CONTROL AND TREATMENT TECHNOLOGY FOR POLLUTANTS OTHER THAN HEAT
-RAINFALL RUNOFF WASTE STREAMS-

Waste Streams: Coal-pile drainage
Yard and roof drainage
Construction activities

Technology / Pollutant	Cost / Effluent Reduction Benefit, [mill/kwh] , [mg/l]$_{\text{effluent concentration}}$
Present System(C)	Base
Conventional Solids Separation(S)	0.01 mill/kwh
Oil and grease	no reduction
pH value	no change
Total suspended solids	15 mg/l
One-Stage Chemical Treatment of Polluted Portions of Runoff (CT)	0.01 mill/kwh
Oil and grease	10 mg/l
pH value	6.0 to 9.0
Total suspended solids	15 mg/l
Numerous misc. parameters	significant reductions
One-Stage Chemical Treatment of Entire Runoff(N)	unknown
Two-Stage Chemical Treatment(N)	unknown

Meaning of Symbols
C = commonly employed
CT = currently transferrable
PT = potentially transferrable
N = not known to be practiced
S = some usage

PART A

CHEMICAL WASTES

SECTION VIII

COST, ENERGY AND NON-WATER QUALITY ASPECTS

Introduction

This section discusses cost estimates for the control and treatment technology discussed in the previous section, energy requirements for this treatment technology and non-water quality related aspects of this technology such as recovery of byproducts, ultimate disposal of brines and sludges, and effects on the overall energy situation.

The estimates contained herein assume ample availability of land. It is recognized that powerplants located in highly developed urban areas may incur costs several times in excess of those shown. Other assumptions include no unusual foundation or site preparation problems. Estimates do not consider regional differences in construction costs.

Due to the wide range of water volumes required from plant to plant for the individual unit operations involved, and further, due to the wide range (from plant to plant) of costs per unit volume of water treated, which are further related to the effluent reductions obtained, the costs vary widely for the removal of specific pollutants to various degrees. For example, boiler fireside chemical cleaning volumes vary from 24,000 gal to 720,000 gal per cleaning, with cleaning frequencies ranging from 2 to 8 times per year. The operating costs of chemical precipitation treatment for copper and iron removal to 1 mg/l effluent concentration and for chromium removal to an effluent of 0.2 mg/l range from $0.10 to $1.30/1000 gal. Furthermore, there are approximately 10 or more separate unit operations which are sources of waste water at power generating plants, each with its station-specific flow rate and waste water characteristics, as well as cost peculiarities. Site-related factors concerning the practicability of various re-use practices make these practices even more difficult to cost, due to the added complexities involved.

Central Treatment Plant Costs

Although powerplants produce many different wastewater streams with different pollutants and different flow characteristics, the most feasible concept of treatment consists of the combination of all compatible wastewater streams, with equalization or holding tanks to equalize the flow through the treatment units. Figure A-VIII-1 shows a typical flow diagram for a possible central treatment plant for coal-fired powerplants.

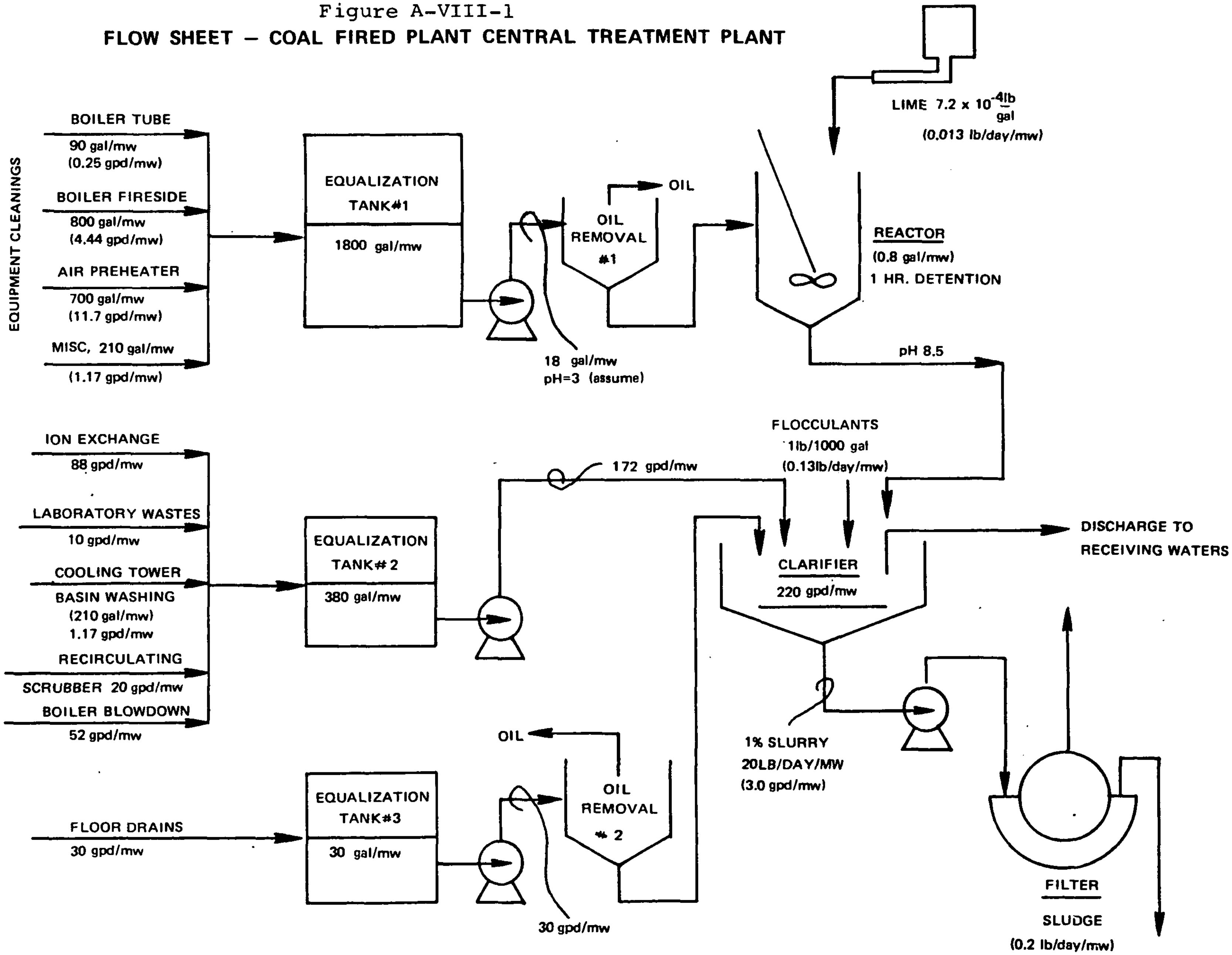
Wastewater treatment facilities for treating chemical wastes therefore consist essentially of a series of tanks and pumps, and interconnecting piping: special equipment such as pressure filters, vacuum filters, centrifuges, or incinerators as may be required. Tanks serve for several purposes, as equalization tanks to permit the following units to operate under constant flow conditions, as neutralization tanks to adjust acidity or alkalinity, or as coagulation and precipitation tanks to provide for mixing of a coagulant, the formation of the precipitates and the separation of the precipitates from the treated flow. In most cases, the mechanical equipment inside the tank is a minor cost consideration, although in the case of certain types of tanks used for softening and similar reactions the equipment cost may be significant. Chemical feeders may be of the dry volumetric type or of the solution type. In either case, the cost of the feeder is likely to be minor, although costs of associated equipment for the storage of chemicals is often significant. A substantial amount of data is available on chemical feeders.

Cost curves are given in Figures A-VIII-2, 3 for the principle items of equipment required for the treatment of chemical type waste water.

A cost analysis is based on a central treatment plant as shown in Figure A-VIII-1 for all low-volume waste waters containing chemical pollutants. The design flows assumed for this plant are given in the figure. The estimated equipment sizes and costs for central treatment plants corresponding to 100 Mw and 1,000 Mw coal-fired plants, oil-fired plants, gas-fired plants and nuclear plants are given in Tables A-VIII-1, 2, 3 and 4 respectively. Total capital costs for these plants, including equipment, installation, construction, engineering and contingency costs, are given in Tables A-VIII-5, 6, 7 and 8 respectively. Capital costs for plants of capacities other than 100 and 1,000 Mw can be estimated from Figure A-VIII-4. Annual costs, including fixed changes against capital and operating and maintenance costs are given in Tables A-VIII-9, 10, 11 and 12. Cost for labor, chemicals and power are based on the cost versus

Figure A-VIII-1

FLOW SHEET — COAL FIRED PLANT CENTRAL TREATMENT PLANT



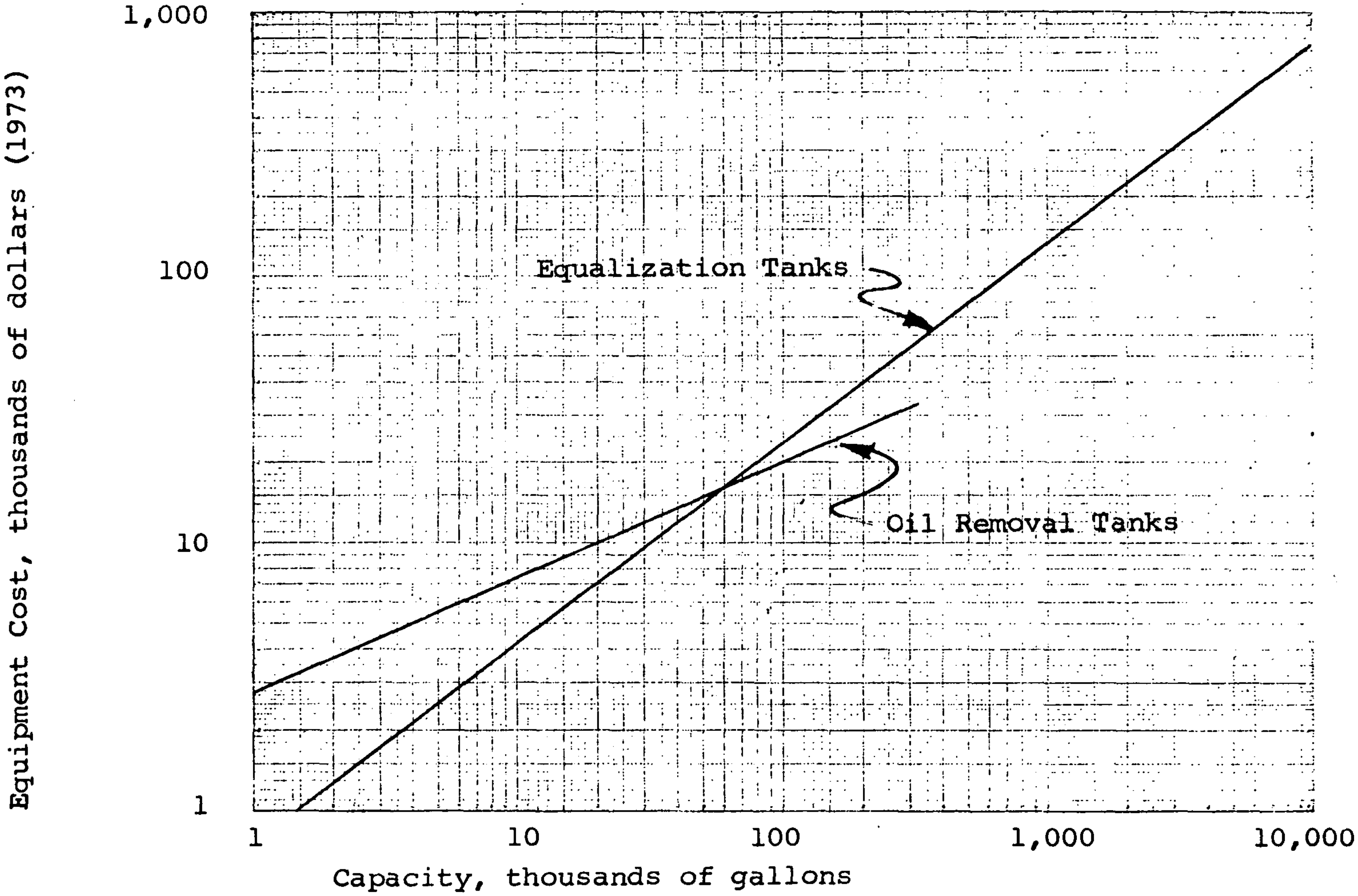


Figure A-VIII-2 Costs of Equalization Tanks and Oil Removal Tanks

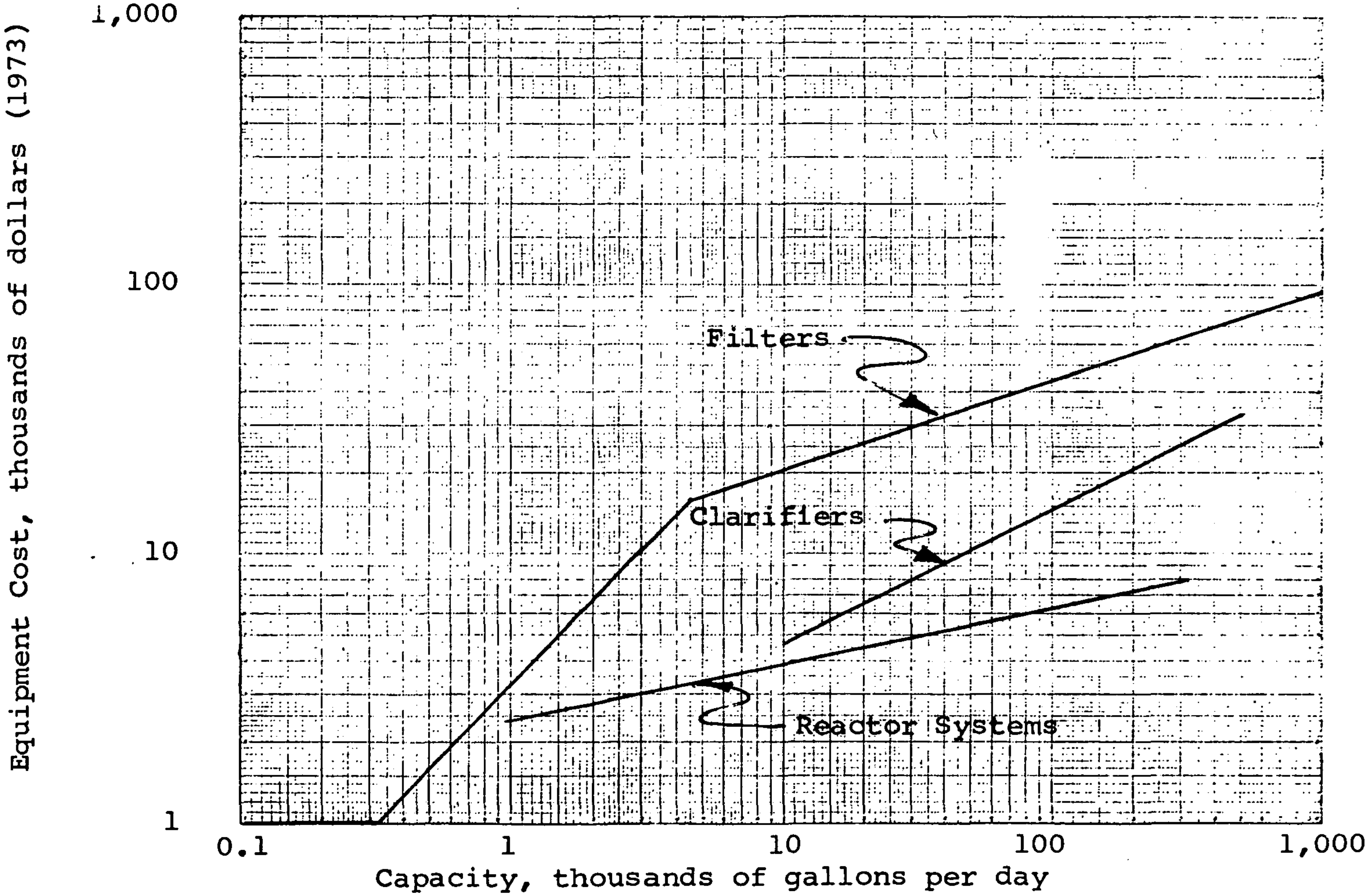


Figure A-VIII-3 Costs of Clarifiers, Reactor Systems, and Filters

Table A-VIII-1
Estimated Equipment Costs
Central Treatment Plant for Coal-Fired Powerplants

Description	100 Mw		1000 Mw	
	Size/Capacity	$(1000)	Size/Capacity	$(1000)
Equalization Tank No.1 (gal)	180,000	38	1,800,000	111
No.2	38,000	12	380,000	65
No.3	3,000	1.7	30,000	10
Oil Removal Tank No.1 (gal)	1,800	3.5	18,000	9.5
No.2	3,000	4.5	30,000	12.5
Reactor System (GPD)	1,800	2.7	18,000	4.5
Clarifier (GPD)	22,000	7	220,000	22
Filter* (GPD)	300	1	3,000	10
Pumps and Piping	-	10.9	-	20.2
Major Equipment Cost		81.3		264.7

* Note: 5 gpm/ft^2 and $265/ft^2 (UWAG study page II-24)

Table A-VIII-2
Estimated Equipment Costs
Central Treatment Plant for Oil-Fired Powerplants

Description	100 MW		1000 MW	
	Size/Capacity	$(1000)	Size/Capacity	$(1000)
Equalization Tank No.1 (gal)	180,000	38	1,800,000	111
No.2	38,000	12	380,000	65
No.3	1,500	1	15,000	5.8
Oil Removal Tank No.1 (gal)	1,800	3.5	18,000	9.5
No.2	1,500	3.3	15,000	8.6
Reactor System (GPD)	1,800	2.7	18,000	4.5
Clarifier (GPD)	20,500	6.8	205,000	21
Filter* (GPD)	300	1	3,000	10
Pumps and Piping		10.9		20.2
Major Equipment Cost		79.2		255.6

* Note: 5 gpm/ft^2 and \$265/ft^2 (UWAG study page II-24)

Table A-VIII-3

Estimated Equipment Costs
Central Treatment Plant for Gas-Fired Powerplants

Description	100 Mw		1000 Mw	
	Size/Capacity	$ (1000)	Size/Capacity	$ (1000)
Equalization Tank No.1 (gal)	30,000	10	300,000	55
No.2	36,000	11	360,000	62
Reactor System (GPD)	142	1.5	1,420	2.6
Clarifier (GPD)	15,300	5.8	153,000	18
Filter* (GPD)	210	1	2,100	7
Pumps and Piping **		5.5		10.1
Major Equipment Cost		34.8		154.7

* Note: 5 gpm/ft^2 and $265/ft^2 (UWAG study page II-24)

** Note: Assumed to be 50% of the size for the corresponding coal-fired case

Table A-VIII-4
Estimated Equipment Costs
Central Treatment Plant for Nuclear Powerplants

Description	100 Mw		1000 Mw	
	Size/Capacity	$(1000)	Size/Capacity	$(1000)
Equalization Tank No.1 (gal)	21,000 36,000	7.2 11	210,000 360,000	41 62
Reactor System (GPD)	142	1.5	1,420	2.6
Clarifier (GPD)	15,300	5.8	153,000	18
Filter* (GPD)	210	1	2,100	7
Pumps and Piping **		5.5		10.1
Major Equipment Cost		32		140.7

* Note: 5 gpm/ft^2 and $265/ft^2 (UWAG study page II-24)

** Note: Assumed to be 50% of the size for the corresponding coal-fired case

Table A-VIII-5

Estimated Total Capital Costs
Central Treatment Plant for Coal-Fired Powerplants

Item	100 Mw		1000 Mw	
	Retrofit $(1000)	New Sources $(1000)	Retrofit $(1000)	New Sources $(1000)
Major Equipment Cost	81.3	81.3	264.7	264.7
Installation Cost @ 50% for new sources @ 100% for retrofit	81.3	40.7	264.7	132.4
Instrumentation @ 20%	16.3	16.3	52.9	52.9
Construction Cost	178.9	138.3	582.3	450.0
Engineering @ 15%	26.8	20.8	87.3	67.5
Contingency @ 15%	26.8	20.8	87.3	76.5
Total Capital Cost ($/kw)	232.5 (2.33)	179.9 (1.80)	756.9 (0.76)	585.0 (0.59)

Table A-VIII-6
Estimated Total Capital Costs
Central Treatment Plant for Oil-Fired Powerplants

Item	100 Mw		1000 Mw	
	Retrofit $(1000)	New Sources $(1000)	Retrofit $(1000)	New Sources $(1000)
Major Equipment Cost	79.2	79.2	255.6	255.6
Installation Cost @ 50% for new sources @ 100% for retrofit	79.2	39.6	255.6	127.8
Instrumentation @ 20%	15.8	15.8	51.2	51.2
Construction Cost	174.2	134.5	562.4	434.6
Engineering @ 15%	26.2	20.2	84.4	65.3
Contingency @ 15%	26.2	20.2	84.4	65.3
Total Capital Cost ($/kw)	226.6 (2.27)	175.0 (1.75)	731.2 (0.73)	565.2 (0.57)

Table A-VIII-7
Estimated Total Capital Costs
Central Treatment Plant for Gas-Fired Powerplants

Item	100 MW		1000 MW	
	Retrofit $ (1000)	New Sources $ (1000)	Retrofit $ (1000)	New Sources $ (1000)
Major Equipment Cost	34.8	34.8	154.7	154.7
Installation Cost @ 50% for new sources @ 100% for retrofit	34.8	17.4	154.7	77.4
Instrumentation @ 20%	7.0	7.0	30.9	30.9
Construction Cost	76.6	59.2	340.3	263.0
Engineering @ 15%	15.3	8.9	51.1	39.5
Contingency @ 15%	15.3	8.9	51.1	39.5
Total Capital Cost ($/kw)	107.2 (1.07)	77.0 (0.77)	442.5 (0.44)	342.0 (0.34)

Table A-VIII-8
Estimated Total Capital Costs
Central Treatment Plant for Nuclear Powerplants

Item	100 Mw		1000 Mw	
	Retrofit $(1000)	New Sources $(1000)	Retrofit $(1000)	New Sources $(1000)
Major Equipment Cost	32.0	32.0	140.7	140.7
Installation Cost @ 50% for new sources @ 100% for retrofit	32.0	16.0	140.7	70.4
Instrumentation @ 20%	6.4	6.4	28.1	28.1
Construction Cost	70.4	54.4	309.5	239.2
Engineering @ 15%	10.6	8.1	46.5	35.8
Contingency @ 15%	10.6	8.1	46.5	35.8
Total Capital Cost ($/ kw)	91.6 (0.92)	70.6 (0.71)	402.5 (0.40)	310.8 (0.31)

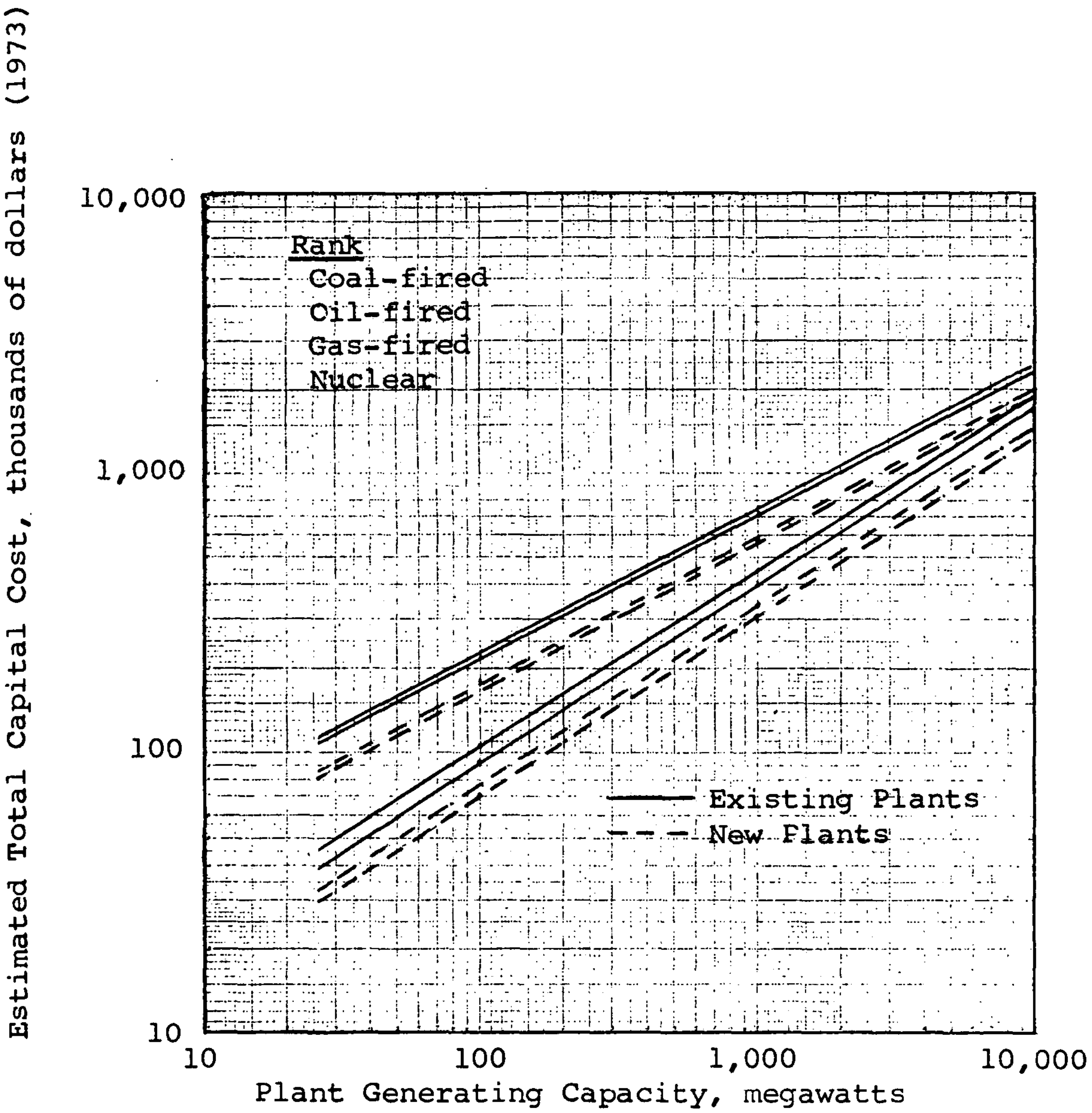


Figure A-VIII-4 Estimated Total Capital Costs of Central Treatment Plants

Table A-VIII-9
Estimated Annual Costs
Central Treatment Plant for Coal-Fired Powerplants*

Item	100 Mw		1000 Mw	
	Retrofit $ (1000)	New Sources $ (1000)	Retrofit $ (1000)	New Sources $ (1000)
Construction Cost (CC)	178.9	138.3	582.3	450.0
Total Capital Cost (TCC)	232.5	179.9	756.9	585.0
Maintenance @ 3% of CC	5.4	4.1	17.5	13.5
Fixed Charges @ 15% of TCC	34.9	27.0	113.5	87.7
Chemicals and Power	4.2	4.2	38.0	38.0
Labor	100.0	100.0	190.0	190.0
Total Annual Cost	144.5	135.3	359.0	329.2
Unit Cost, mills/kwh				
Base-load (0.77 capacity factor)#	0.214	0.201	0.055	0.049
Cyclic (0.44 capacity factor)#	0.375	0.353	0.096	0.086
Peaking (0.09 capacity factor)#	1.84	1.72	0.467	0.422

* Note: Flow basis is 220 GPD/Mw

\# Note: Assumes full costs of maintenance, chemicals, power, and labor. These costs would actually be less than shown and would reflect the extent of utilization of the plant.

Table A-VIII-10
Estimated Annual Costs
Central Treatment Plant for Oil-Fired Powerplants*

Item	100 Mw		1000 Mw	
	Retrofit $ (1000)	New Sources $ (1000)	Retrofit $ (1000)	New Sources $ (1000)
Construction Cost (CC)	174.2	134.5	562.4	434.6
Total Capital Cost (TCC)	226.6	175.0	731.2	565.2
Maintenance @ 3% of CC	5.3	4.0	16.9	13.0
Fixed Charges @ 15% of TCC	34.0	27.2	109.7	84.8
Chemicals and Power	4.0	4.0	36.0	36.0
Labor	98.0	98.0	185.0	185.0
Total Annual Cost	141.3	133.2	347.6	318.8
Unit Cost, mills/kwh				
Base-load (0.77 capacity factor) #	0.211	0.198	0.052	0.047
Cyclic (0.44 capacity factor) #	0.369	0.346	0.091	0.082
Peaking (0.09 capacity factor) #	1.80	1.69	0.445	0.400

* Note: Flow basis is 205 GPD/Mw

Note: Assumes full costs of maintenance, chemicals, power, and labor. These costs would actually be less than shown and would reflect the extent of utilization of the plant.

Table A-VIII-11
Estimated Annual Costs
Central Treatment Plant for Gas-Fired Powerplants*

Item	100 Mw		1000 Mw	
	Retrofit $ (1000)	New Sources $ (1000)	Retrofit $ (1000)	New Sources $ (1000)
Construction Cost (CC)	76.6	59.2	340.3	263.0
Total Capital Cost (TCC)	107.2	77.0	442.5	342.0
Maintenance @ 3% of CC	2.3	1.8	10.2	7.9
Fixed Charges @ 15% of TCC	16.1	11.5	66.4	51.3
Chemicals and Power	3.0	3.0	28.0	28.0
Labor	90.9	90.0	175.0	175.0
Total Annual Cost	111.4	106.3	279.6	262.2
Unit Cost, mills/kwh				
Base-load (0.77 capacity factor)#	0.165	0.159	0.042	0.039
Cyclic (0.44 capacity factor)#	0.289	0.277	0.073	0.068
Peaking (0.09 capacity factor)#	1.41	1.36	0.356	0.335

* Note: Flow basis is 155 GPD/Mw.

Note: Assumes full annual costs of maintenance, chemicals, power, and labor. These costs would actually be less than shown and would reflect the extent of utilization of the plant.

Table A-VIII-12
Estimated Annual Costs
Central Treatment Plant for Nuclear Powerplants*

Item	100 Mw		1000 Mw	
	Retrofit $ (1000)	New Sources $ (1000)	Retrofit $ (1000)	New Sources $ (1000)
Construction Cost (CC)	70.4	54.4	309.5	239.2
Total Capital Cost (TCC)	91.6	70.6	402.5	310.8
Maintenance @ 3% of CC	2.1	1.6	9.3	7.2
Fixed Charges @ 15% of TCC	13.8	10.6	60.4	46.7
Chemicals and Power	3.0	3.0	28.0	28.0
Labor	90.0	90.0	175.0	175.0
Total Annual Cost	108.9	105.2	272.7	256.9
Unit Cost, mills/kwh				
Base-load (0.77 capacity factor)#	0.162	0.156	0.040	0.038
Cyclic (0.44 capacity factor) #	0.284	0.273	0.070	0.066
Peaking (0.09 capacity factor) #	1.39	1.33	0.345	0.322

* Note: Flow basis is 155 GPD/Mw

\# Note: Assumes full annual costs of maintenance, chemicals, power, and labor. These costs would actually be less than shown and would reflect the extent of utilization of the plant.

capacity functions shown in Figure A-VIII-5, which in turn are based on the following units cost:

Operations Labor	$20,000/man-year
Lime	$27/ton
Flocculant	$0.05/lb
Electricity	12 mills/kwh

Costs for Wastes Not Treated at Central Treatment Plant

The following wastes are not considered suitable for treatment at a central treatment plant for chemical wastes:

Cooling water (once-through system), cooling water blowdown (closed system), sanitary wastes, roof and yard drains, coal pile runoff, intake screen backwash, radwastes, nonrecirculating ash sluice water, nonrecirculating wet-scrubbing air pollution control waste water, once-through (nonrecirculating) house service water. Recirculating bottom ash sluicing water blowdown is considered separately although incorporation in the central treatment plant may be feasible in some instances.

Cooling Water-Once Through Systems

The treatment technology for once-through condenser cooling water systems consists of maintaining the residual chlorine in the effluent below an established limit by controlling the chlorine added to the system. The capital costs involved consist of the cost of a residual chlorine analyzer and feedback controls to adjust the feed rate. The installed cost of a residual chlorine analyzer and control equipment is estimated to be about $5,000 regardless of size of unit. This cost is easily amortized through savings realized by reduced consumption of chlorine.

Costs of on-line mechanical cleaning of condenser tubes are given in Tables A-VIII-13 and A-VIII-14.

There are several alternative materials available which can replace copper based alloys as condenser tube materials. The most widely used copper alloys are admiralty, with a copper content of 70% and Cupro-nickel alloys with a copper content of from 70 to 90 percent. Replacement materials consist of stainless steel which provides a good option in inland fresh water locations and titanium which finds

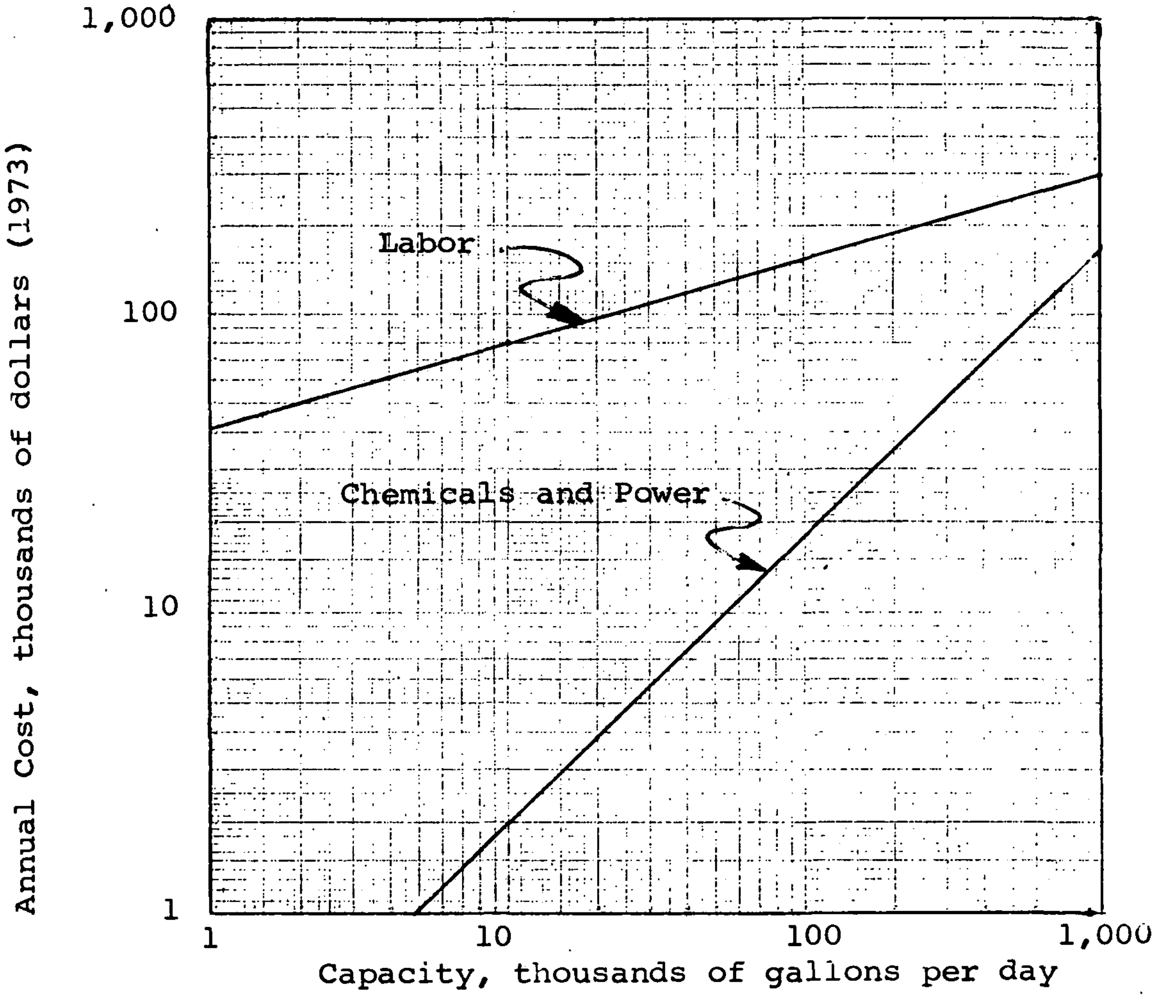


FIGURE A-VIII-5 Annual Costs of Labor, Chemicals and Power for Chemical Treatment

Table A-VIII-13

Capital and Operating Costs for On-Line Tube Cleaning Equipment

System	Capital Costs		Annualized Capital Mills/kwh(b)	Operating and Maintenance Costs		Total Annual Costs Mills/kwh
	$\$/10^6$ Btu/hr Rejected	$/kw		$\$10^6$ Btu/hr Rejected	Mills/kwh	
Recirculating Sponge Balls	120-290	0.48-1.16	.008-.020	2.85-5.15	0013-.0024(a)	.009-.022
Plastic Brushes	38-125	0.15-.50	.003-.009	3.07-6.12	.0014-.0028(c)	.004-.012

a. Power costs estimated at 4 mills/kwh. Maintenance labor estimated at $7.00/hr
b. Based on 15% per year
c. Includes allowance for replacing brushes every five years.

Table A-VIII-14

Typical Sponge Rubber Ball Tube Cleaning System Costs [(a)] 389

Unit Capacity, Mw	Cooling Water Recirculation Rate gpm	Equipment Cost [(b)]		Additional Power Required to Operate System, kw	Replacement Ball Costs ,$/yr	Maintenance Labor Rqd, hrs/wk
		$	$/Mw			
900	405,000	$229,000	$254	70	$6,400	1
1,190	440,000	312,000	284	76	15,000	1
680	220 000	165,000	243	46	6,000	1
950	882,000	556,000	585	166	11,000	2

(a) Data provided by Mr. W. I. Kern, Amertap Corporation

(b) Estimated total installed cost of system, including capital equipment for new installation = 2 x equipment cost.

greater applicability in coastal plants operating on sea water. Both stainless and titanium are highly resistant to corrosion which allows the use of thinner tube thicknesses in most applications. The overall heat transfer coefficient for both of these materials is somewhat less, at normal operating conditions, than the copper based alloys, thus requiring a greater tube length. In addition, the cost of titanium is considerably more than copper and these two factors have combined to limit the use of titanium to a relatively few coastal applications. However, several plants have retubed with this material based on economical analysis which showed that reduced tube failures lowered overall maintenance costs. Stainless steel, on the other hand is competitive with the copper based alloys in terms of price and its greater tolerance to both erosion and corrosion has led to a dramatic growth in its use over the last 10 years.

Table A-VIII-15, shows a cost comparison of the use of these alternatives tube materials for typical condenser conditions (7.5 ft/sec and 1.0" diameter tubes) and recent (1974) materials prices. The table shows that the use of titanium to retube an existing condenser might add as much as 90% to the retubing cost. The use of stainless steel is competitve with the cost of both admiralty and copper-nickel tubing.

Installation of alternate tube material at existing plants can be done at the time of normal condenser retubing. Major condensers can be completely retubed in approximately one month.

Cooling Water Blowdown - Closed Systems

The treatment technology is essentially the same as for a once-through system. Residual chlorine is monitored in the effluent, and blowdown is permitted only when the residual chlorine is below the established limit. It is possible to schedule blowdown only at such times when the residual chlorine level meets the effluent limitation. Additional costs would occur in cases where sedimentation would be provided for suspended solids removal, and where chemical treatment would be required for removal of chromium, phosphorus, or zinc. Sedimentation costs, where needed, would be approximately 7 cents/1000 gallons treated and chemical treatment costs, where needed, would be about $1/1000 gallons.

Capital investment and operating costs were estimated for various chromate reduction systems, based on the flow diagram shown on Figure A-VII-17 and the wastewater

Table A-VIII-15

COST COMPARISON OF ALTERNATIVE TUBE MATERIAL
(1"Ø tubes; velocity 7.5 ft/sec)

Material	Copper Content (%)	BWG	Overall Heat Transfer Coefficient (Btu/hr/ft^2/F)	Heat Transfer Multiplier	Unit Cost $/ft	Cost Multi-plier	Total Multi-plier
Admiralty	20	18	600	1.00	0.74	1.00	1.00
90/10 Cupro-Nickel	90	20	570	1.05	0.96	1.29	1.36
Titanium	0	22	535	1.12	1.26	1.70	1.90
Stainless Steel (316)	0	22	520	1.15	0.76	1.02	1.17

characteristics shown in Table A-VII-11. Estimates were based on a 1,000 Mw fossil-fuel plant operating at a heat rate of 10,400 Btu/Kwh (Efficiency = 33%) and having a circulating water flow rate of 600,000 gpm at a temperature differential of 20°F. For such a system, the amount of blowdown required depends on the characteristics of the makeup water supply, in particular, the number of cycles of concentration possible before scaling occurs. The capital cost of a chromate reduction system is in turn a function of the blowdown rate. Table A-VIII-16 shows the capital investment costs for chromate reduction systems for various blowdown rates and the corresponding number of cycles of concentration.

The maximum number of cycles of concentration can be increased by pretreatment of the makeup supply to reduce the specific parameter limiting the number of cycles of concentration. Thus there are obvious tradeoff possibilities between pretreatment of makeup water and post-treatment of blowdown.

Operating costs of chromate reduction systems consist of capital charges, maintenance, labor, and materials and supplies. The first three items are essentially fixed, but materials and supplies vary with the hours of operation of the system and the level of chromate carried in the system. Table A-VIII-17 shows the various costs as a function of the chromate concentration.

Unit costs for chromate reduction systems are developed in Table A-VIII-18

Typical automatic blowdown control equipment costs are estimated to be $7,300 including installation.[389]. The installation of conventional pH controlling equipment is estimated to be about $3,000.[389]

Table A-VIII-19 taken from Reference 389 gives costs for sedimentation ponds, cooling towers and chemical recovery for blowdown treatment.

Sanitary Wastes

Sanitary wastes are generally discharged to municipal sewerage systems, or if municipal sewers are not available, treated in biological process treatment plants. The volume of sanitary wastes is primarily a function of the size of the labor force. For most powerplants in isolated locations, a minimum size factory preassembled activated sludge type treatment plant will provide adequate treatment.

Table A-VIII-16

CAPITAL INVESTMENT COSTS FOR CHROMATE REDUCTION SYSTEMS

Blowdown M^3/s	Rate gpm	Cycles of Concentration	Capital Cost
	5,400	3	\$780,000
	2,400	5	537,000
	720	10	364,000

Assumptions:
1,000 Mw fossil-fuel
Heat rate 10,400 Btu/kwh (Efficiency = 33%)
600,000 gpm at 20°F ΔT
Evap. - 2%

Table A-VIII-17

VARIABLE OPERATING COSTS FOR MATERIALS AND SUPPLIES CHROMATE REDUCTION SYSTEMS

		Cost per 1000 gal. processed			
Item	Unit Cost	Chromate Concentration, mg/l			
		10	50	100	200
SO_2	\$0.17/lb.	\$.05	\$.11	\$.175	\$.317
H_2SO_4	\$0.02/lb.	.08	.12	.16	.20
NaOH	\$0.04½/lb.	.145	.20	.29	.40
Polymer	\$2.00/lb.	.02	.02	.02	.02
Power	\$0.03/kwh	.0075	.0075	.0075	.0075
		.3025	.4575	.6525	.9345

Table A-VIII-18

UNIT COSTS OF CHROMATE REDUCTION SYSTEMS

Capital Investment Costs

Construction Cost	$413,000
Engineering	62,000
Contingencies	62,000
Total	$537,000

Annual Costs

Capital Charges @15% x Total	$ 80,500
Maintenance @3% x Constr. Cost	12,400
Labor	23,700
Fixed	$116,600
Materials and Supplies	394,400
	$511,000

Unit Costs, mills/kwh

Capacity Factor	1.00	0.67	0.35	0.07
Fixed Costs	0.013	0.020	0.038	0.191
Materials and Supplies	0.045	0.045	0.045	0.045
Total	0.058	0.065	0.083	0.263

Note: 1000 Mw fossil-fuel plant, 5 cycles, 10 mg/l Chromate

Table A-VIII-19 Blowdown Treatment System Costs 389

System	Installation Costs $/m^3/hr fed	Annualized Capital Costs[(a)] $/1,000 m^3 fed	Operating and Maintenance Costs[(a)] $/1,000 m^3 fed	Total Costs $/1,000 m^3 fed	Principal System Characteristics
Sedimentation Pond	3-6	0.05-0.10	0.01-0.02[(c)]	0.06-0.12	1. Provides solids settling chlorine dissipation, and usually some cooling 2. Costs dependent on land values and climate.
Mechanical Draft Evaporative Cooling Tower	20-30	0.34-0.51	2.20-2.75	2.54-3.26	1. Allows positive control of blowdown temperature. 2. May require biocide treatment.
Chromate Recovery	8400	144	37	181	

(a) Based on 15 percent per year

(c) Maintenance estimated at 3 percent per year of capital investment

The installed cost of these plants is estimated to be $25,000 - $35,000 depending on geographic location.

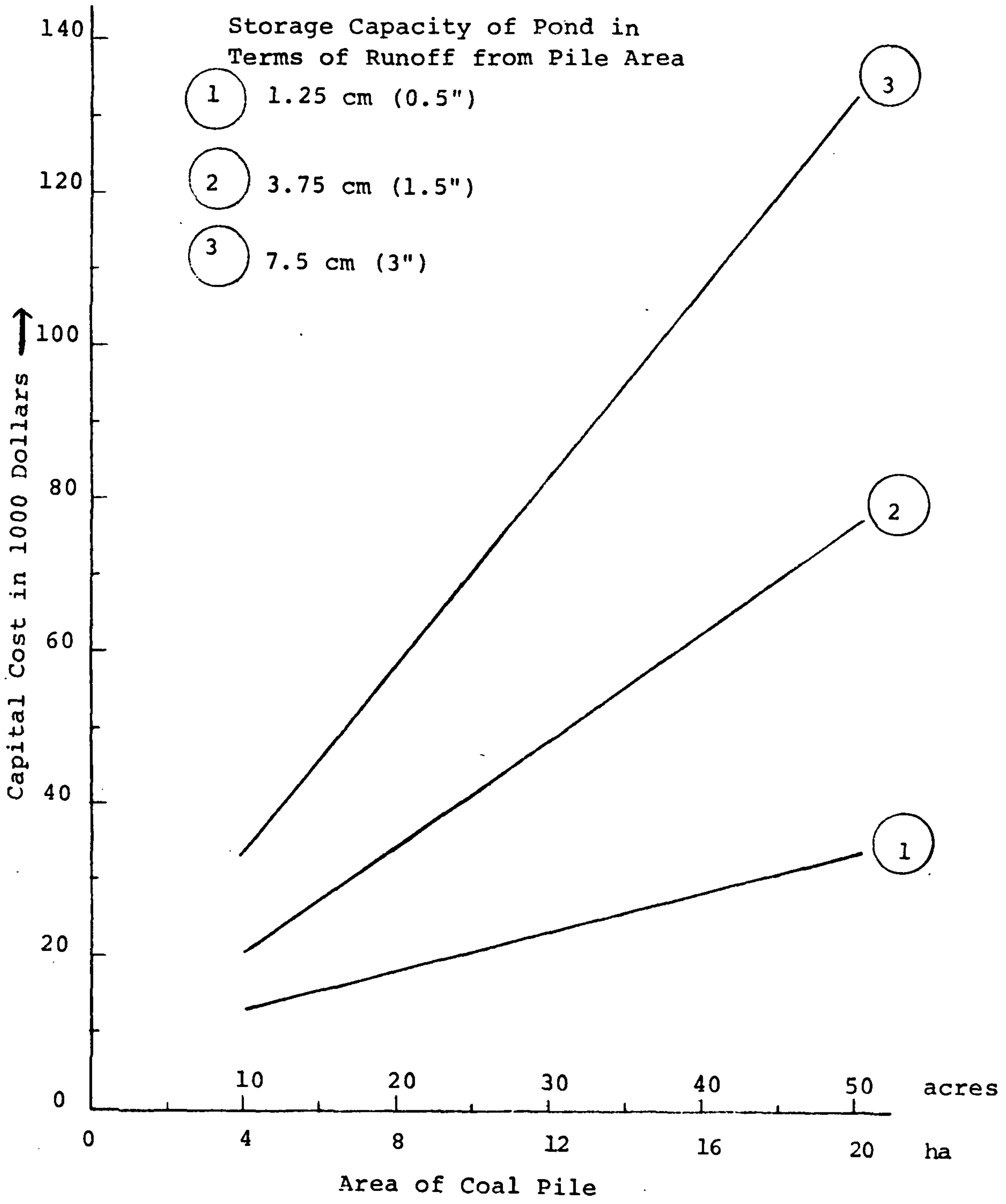
Materials Storage and Construction Runoff

The cost of materials storage and construction runoff treatment is a function of the meteorological conditions at each particular site. Capital costs of lined retention ponds capable of holding various volumes of runoff are shown in Figure A-VIII-6. Costs for neutralizing chemicals will vary with pH and frequency of treatment.

Systems to collect coal pile run-off installed in recent years vary considerably, in complexity and costs. Elaborate collection systems would be required at some plants where unusual terrain conditions and space limitations exist. At one midwestern plant of about 1,000 Mw capability a new system collects run-off by gravity in a concrete basin from which it is pumped to an adjacent ash settling basin. The collection and treatment systems cost about $500,000 to install. On the other hand, at one eastern plant such collection can be accomplished merely by grading of adjacent areas to route run-off by gravity to an existing ash pond. This particular system cost about $20,000 to install.[444]

The assumptions made for estimating the cost of constructing facilities for containment of the runoff from a one acre area for the storage of coal and other materials are given below:[458]

1. The estimates of cost are based on a 10-year, 24 hour event in which 0.114 m (4.5 in) of rain falls.
2. The surface of the land to be used as a storage area has a 3 degree grade.
3. The soil is permeable so that an impermeable subbase must be prepared. The impermeable base is prepared by grading 0.6 m (2 ft) from the edge of the square storage area. This graded surface is backfilled, graded level, and compacted to a depth of 0.15 m (5 in). Polyethylene sheeting is placed on the dikes described later. Overlaps of 0.3 m (12 in) at the seams of the sheeting are used. A 0.45 m (1.5 ft) layer of earth is than graded and compacted over the polyethylene, including the face of the dikes described later.
4. Dikes are constructed across the downhill end of the square storage area, and for about one-third



COST FOR COAL PILE RUNOFF COLLECTION
FIGURE A-VIII-6

the distance up each side. The dikes will be 2.5 m (8.2 ft) high at the crest. The crest will be 1.5 m (5 ft) wide, and the total width of the base of the dikes, which are trapezoidal in cross-section, will be 12 m (40 ft). The dike at the downhill end of the storage area is provided with a concrete sluiceway so that water can overflow in the event of a catastrophic rainfall. The crest of the sluiceway is 1.5 m (5 ft) above the grade level of the base of the dike. The dikes are constructed prior to placement of the polyethylene sheets so that the upstream faces of the dikes can be covered with polyethylene, and then earth, and compacted.

5. Trenches are dug across the uphill end of the storage area and along each side to divert runoff into the diked area.

6. Neutralization facilities are used to maintain within proper limits the pH of any overflow from the diked area at a rate of up to 4.5 acre-inches averaged over one day, as controlled by the weir. Any flow in excess of this level is allowed to bypass the treatment facility. These facilities include a storage hopper and feeder for lime and a pH sensor and controller along with necessary wiring. Mixing of the lime with overflow from the containment pond, when overflow occurs, is accomplished by the use of a mixer in the downstream trough of the sluiceway. The lime feeder is controlled by a pH controller with the sensor downstream from the sluiceway. The pH controller will activate the feeder in proportion to the amount the pH is lower than a pre-selected point.

7. A settling basin, created by excavation to build the dike, is sized to provide a detention time of 24 hours (taking into account the build-up of sediment for the volume of the 10-year 24 hour event. An overflow is provided. The settling basin is not lined. See Figure A-VIII-7 which is a sketch of the runoff treatment system.

The unit costs used in estimating the above cost are \$1.18/cu m (\$0.90/cu yd) for grading, filling and compacting; \$0.27/sq m (\$0.025/sq ft) for purchasing 10-mil polyethylene film (quoted price); and \$1.65/lineal meter (\$0.50/lineal ft) for machine trenching.[458]

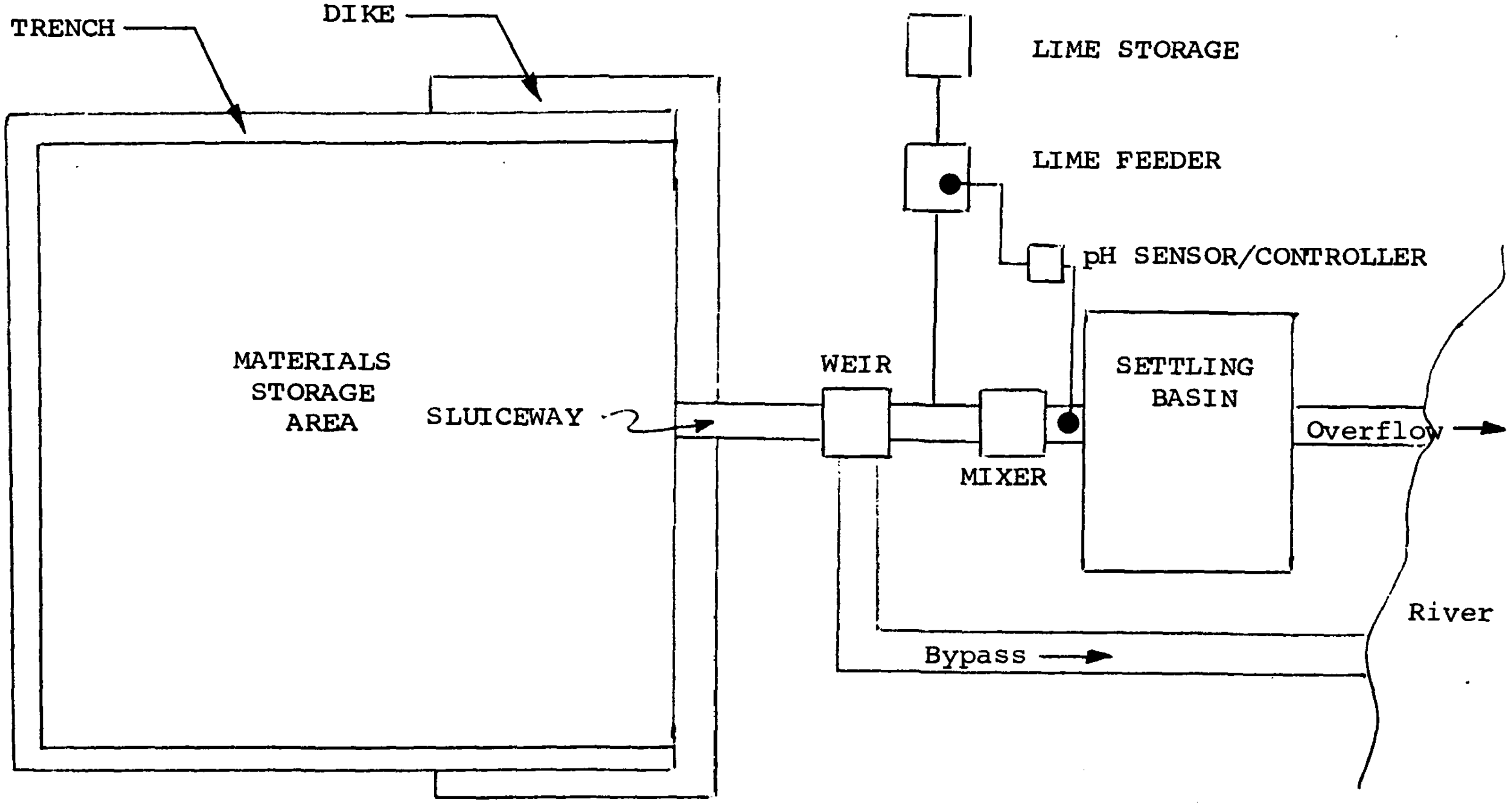


Figure A-VIII-7 Materials Storage Area Runoff Treatment

The total cost of the 0.404 hectare (1 acre) area for storing coal and other materials is estimated to be $17,000, including the cost for preparing impermeable sub-base ($3,300), trenches and dikes ($1,100), and the sluiceway and neutralization facilities including installation ($8,500).[458]

For a larger facility, the cost of trenches and dikes are estimated to be proportional to the square root of the size of the storage area, since their length is proportional to the square root of the enclosed area. The cost of the sluiceway and neutralization facilities are estimated to be proportional to the 0.6 power of the size of the storage area, since the cost versus size characteristics of the components involved can be approximated using this scale factor.[466] Estimated cost for treatment of runoff from materials storage areas and construction activities for a 100 Mw and a 1,000 Mw coal-fired plant is given in Table A-VIII-20. Estimated costs for plants of other sizes are shown in Figure A-VIII-10. The controlled area is assumed to be 0.03 acres/Mw in each case, which is comprised almost entirely of the area of the coal pile. Costs for oil-fired, gas-fired, and nuclear plants would therefore be relatively insignificant.

Intake Screen Backwash

The incremental cost of land disposal of debris removed from intake screens would be insignificant in most cases.

Floor and Yard Drains

The installed cost of two API-type oil-water separators at plant no. 3702 (400 Mw) is $70,000, or $0.18/kw, to treat about 56 l/sec (900 gpm) of a floor and yard drain waste water stream.

Radwaste

No treatment is assumed due to possible hazardous effects of concentrating radioactive wastes.

Ash Sluicing Systems

In cases where sedimentation would be required for suspended solids removal from ash sluice water, the costs would be about 7 cents/1000 gallons. Having achieved adequate suspended solids removal, the effluent is suitable for recycle for ash sluicing, which would involve an incremental cost for pumps, piping and blowdown controls. Flow sheets

Table A-VIII-20
Estimated Costs
Materials Storage and Construction Activities Runoff Treatment
(Coal-Fired Plant)

Item	Model	100 Mw	1000 Mw
Area Controlled @ 0.03 acre/Mw	1 acre	3 acres	30 acres
Trenches, dikes, and settling basin	$ 1,100	$ 1,910	$ 6,030
Sluiceway, diversion, and neutralization facilities	8,500	16,430	65,400
Major Component Cost	$ 9,600	$18,430	$71,430
Installation Cost*	0	0	0
Instrumentation Cost*	0	0	0
Construction Cost	$ 9,600	$18,340	$71,430
Engineering @ 15%	1,440	2,750	10,700
Contingency @ 15%	1,440	2,750	10,700
Total Capital Cost ($/kw)	$12,480	$23,840 (0.24)	$92,830 (0.09)

*Note : Included in major component cost for the adaption of recirculating bottom ash sluicing systems where ash pond sedimentation is already employed are given in Figures A-VIII-8, 9, one of which applies where a combined ash pond is used for both fly ash and bottom ash and the other applies where the ash pond handles only bottom ash. Equipment costs are determined from Figure A-VIII-2, 3. It is assumed, based on site plans of all TVA coal-fired plants that 6,000 ft of return pipe would be needed for a 1,000 Mw plant and further, that the length of return pipe required for plants of other capacities would be proportional to the plant capacity to the 0.6 power. Equipment costs for 100 Mw and 1,000 Mw coal-fired plants are given in Tables A-VIII-21, 22, respectively, for adaptation of recirculating bottom ash systems for the two types of ash pond usage. Corresponding capital costs are given in Tables A-VIII-23, 24. The estimated relation of capital costs to plant generating capacity is given in Figure A-VIII-10. Estimated annual costs are shown in Tables A-VIII-25, 26.

The backfitted configured recirculating ash sluicing system at plant No. 3630, which utilizes no ash pond for sedimentation, cost approximately 3 million dollars to handle the bottom ash from coal burned at a rate of 3,000 tons/day. However, the costs for this system include modification of floor and yard drainage, neutralization and disposal of demineralizer and boiler cleaning wastes and modification of trash screens as well as the configured ash water recycle system. System components include a coal pile trench, collecting basin, filtering pond, neutralizing tanks, pumps, piping, hydrobins, settling tank and recirculating tank. The system is designed to achieve no discharge of pollutants except for those contained in the moisture removed with the settled ash. The plant uses once-through cooling systems.

The capital cost of the configured recirculating bottom ash system at plant No. 5305 was $2,100,000. Unit 1, with a capacity of 700 Mw, was installed in late 1971 and Unit 2, with the same capacity, was installed in late 1972. Assuming the costs to be approximately the same for both units and a 5 percent increase in costs between 1972 and 1973, the 1973 cost for a 700 Mw recirculating bottom ash system would be about $1,100,000. Using this as a base and assuming a 0.6 scale factor on costs versus size (Mw capacity) the capital costs for a 100 Mw unit would be approximately $420,000 or 4.20 $/kw, and $1,360,000 or 1.36 $/kw for a 1,000 Mw unit. Costs would vary from case-to-case.

Figure A-VIII-8
FLOW SHEET — RECIRCULATING BOTTOM ASH SLUICING SYSTEM BLOWDOWN TREATMENT

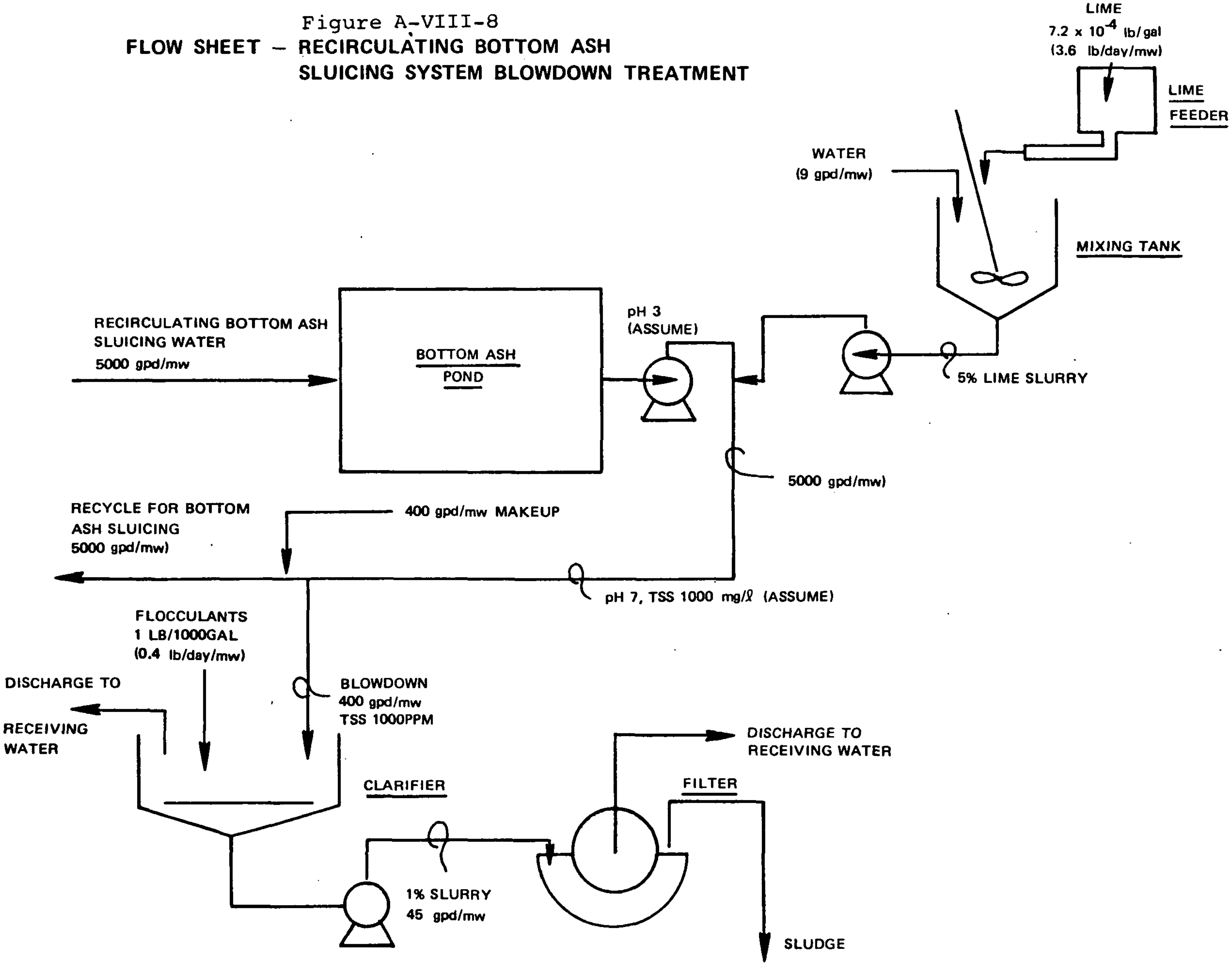
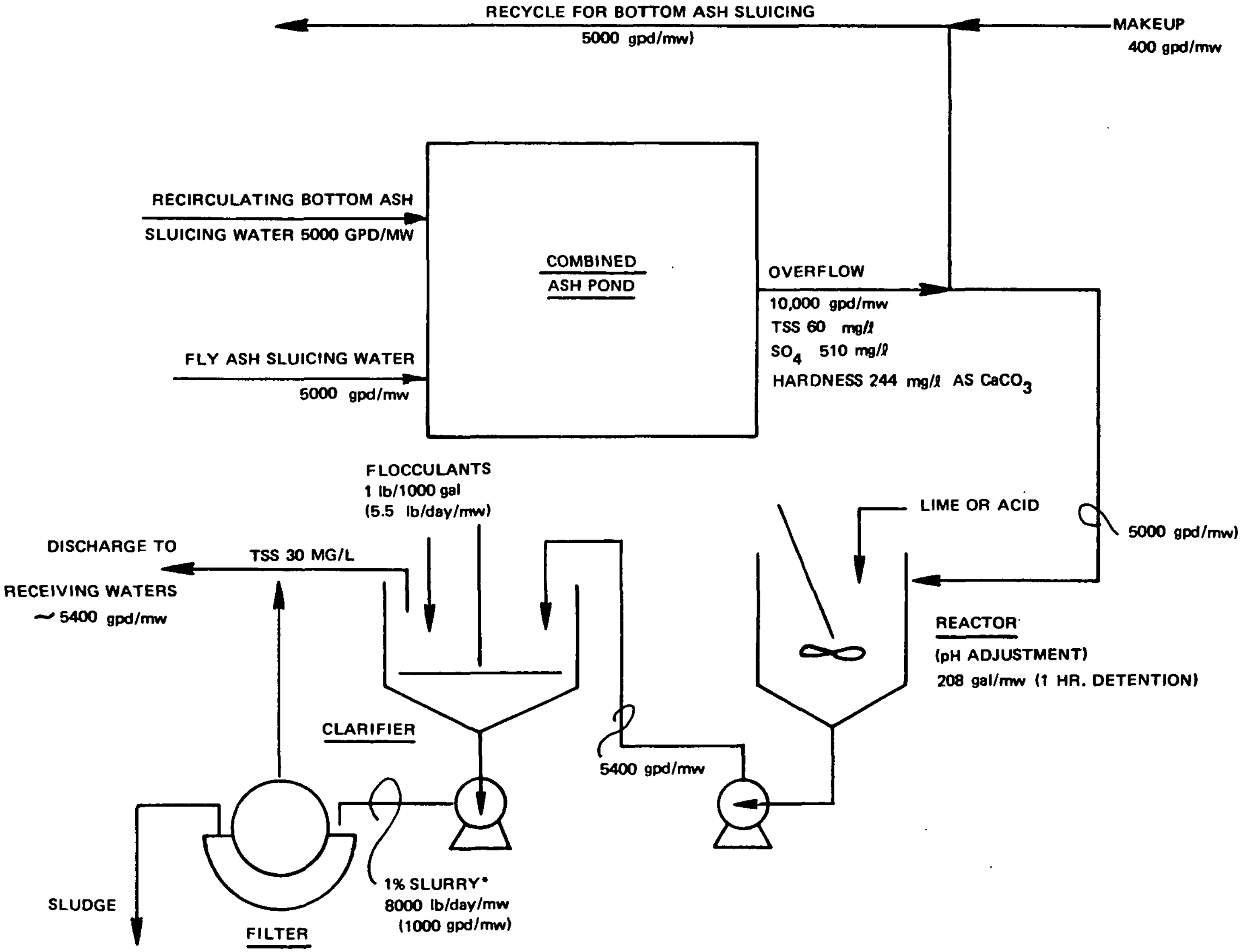


Figure A-VIII-9 TREATMENT OF COMBINED ASH OVERFLOW



(*ASSUMES THAT THE WEIGHT OF PRECIPITATE IS TWICE THE WEIGHT OF POLLUTANTS)

Table A-VIII-21

Estimated Equipment Costs
Recirculating Bottom Ash System
and Treatment of Bottom Ash Blowdown

Component	100 Mw		1000 Mw	
	Size/Capacity	$	Size/Capacity	$
Lime Mixing System (lb/day)	360	2,000	3,600	3,500
Clarifier (gpd)	40,000	9,400	400,000	30,000
Filter (gpd)	4,500	16,000	45,000	34,000
Pumps and Piping		21,500		87,000
Major Equipment Cost		48,900		154,500

Table A-VIII-22
Estimated Equipment Costs
Recirculating Bottom Ash System
and Treatment of Combined Ash Pond Overflow

Component	100 Mw		1000 Mw	
	Size/Capacity	$	Size/Capacity	$
Reactor (gpd)	540,000	9,200	5,400,000	16,000
Clarifier (gpd)	540,000	36,000	5,400,000	210,000
Filter (gpd)	100,000	44,000	1,000,000	94,000
Pumps and Piping		21,500		87,000
Major Equipment Cost		110,700		407,000

Table A-VIII-23

Estimated Capital Costs
Recirculating Bottom Ash System
and Treatment of Bottom Ash Blowdown

Item	100 Mw		1000 Mw	
	Retrofit ($1000)	New Sources ($1000)	Retrofit ($1000)	New Sources ($1000)
Major Equipment Cost	48.9	48.9	154.5	154.5
Installation Cost @50% for new sources @100% for retrofit	48.9	24.5	154.5	77.3
Instrumentation @20%	9.8	9.8	30.9	30.9
Construction Cost	107.6	83.2	339.9	262.7
Engineering @15%	16.1	12.5	50.9	39.4
Contingency @15%	16.1	12.5	50.9	39.4
Total Capital Cost ($/kw)	139.8 (1.40)	108.2 (1.08)	441.7 (0.44)	341.5 (0.34)

Table A-VIII-24
Estimated Capital Costs
Recirculating Bottom Ash System
and Treatment of Combined Ash Pond Overflow

Item	100 Mw		1000 Mw	
	Retrofit ($1000)	New Sources ($1000)	Retrofit ($1000)	New Sources ($1000)
Major Equipment Cost	110.7	110.7	407.0	407.0
Installation Cost @ 50% for new sources @ 100% for retrofit	110.7	55.4	407.0	203.5
Instrumentation @ 20%	22.1	22.1	81.3	81.3
Construction Cost	243.5	188.2	895.3	691.8
Engineering @ 15%	36.5	28.2	134.4	103.9
Contingency @ 15%	36.5	28.2	134.4	103.9
Total Capital Cost ($/kw)	316.5 (3.17)	244.6 (2.45)	1,164.1 (1.16)	899.6 (0.90)

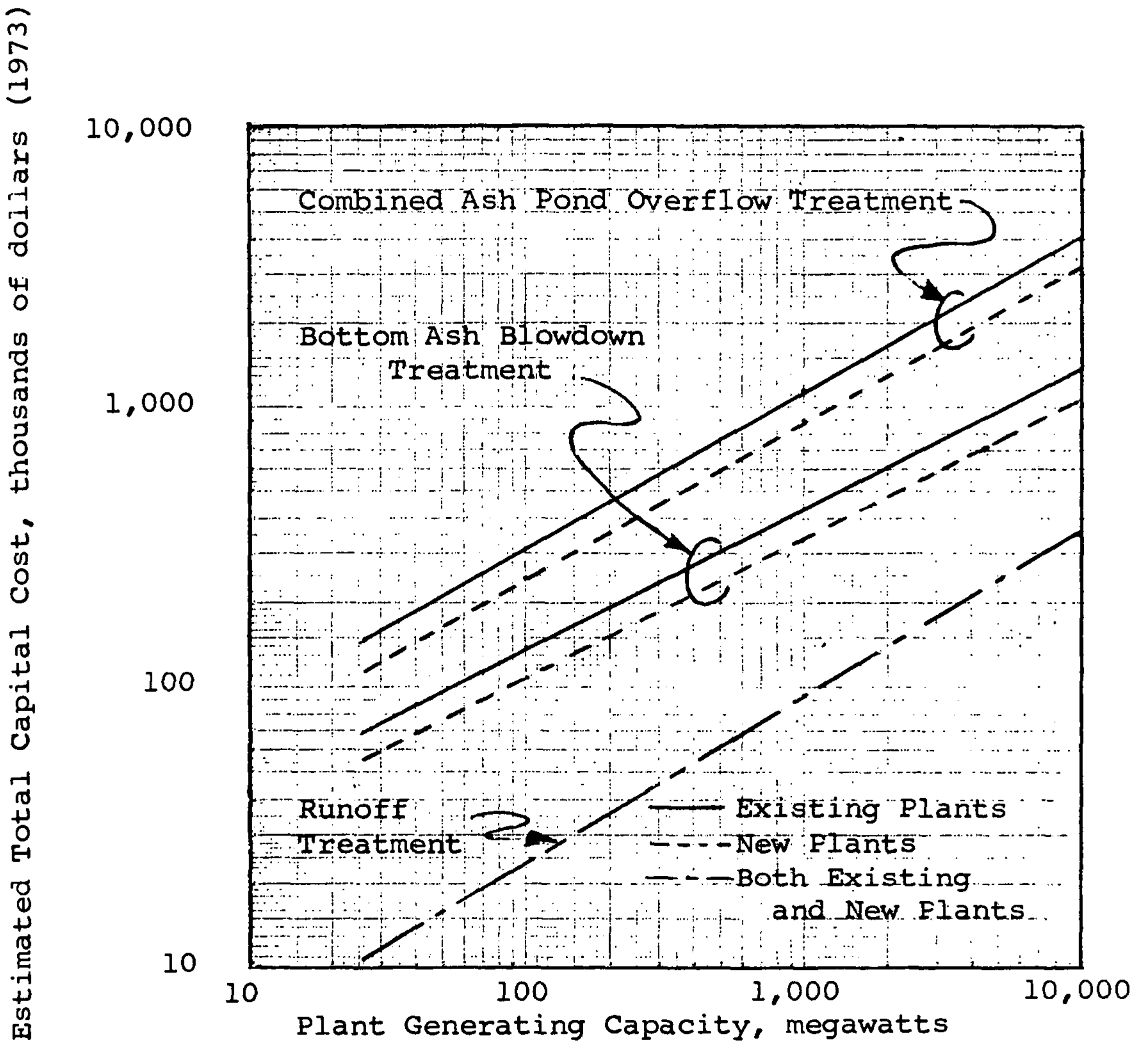


Figure A-VIII-10

Estimated Total Capital Costs for Materials Storage and Construction Activities Rainfall Runoff Treatment, Recirculating Bottom Ash Systems with Blowdown Treatment, and Recirculating Bottom Ash Systems with Treatment of Combined Ash Pond Overflow, All for Coal-Fired Plants

Table A-VIII-25
Estimated Annual Costs
Recirculating Bottom Ash System
and Treatment of Bottom Ash Blowdown*

Item	100 Mw		1000 Mw	
	Retrofit ($1000)	New Sources ($1000)	Retrofit ($1000)	New Sources ($1000)
Construction Cost (CC)	107.6	83.2	399.9	262.7
Total Capital Cost (TCC)	139.8	108.2	441.7	341.5
Maintenance @ 3% of CC	3.2	2.5	10.2	7.9
Fixed Charges @ 15% of TCC	22.0	16.2	66.3	51.3
Chemicals and Power	7.5	4.8	70.0	4.4
Labor	120.0	100.4	230.0	200.0
Total Annual Cost	152.7	123.9	466.5	263.6
Unit Cost, mills/kwh.				
Base-load (0.77 capacity factor)#	0.228	0.183	0.069	0.039
Cyclic (0.44 capacity factor)#	0.398	0.321	0.121	0.068
Peaking (0.09 capacity factor)#	1.95	1.57	0.590	0.334

*Note: Flow basis is 400 GPD/Mw for retrofit and 250 GPD/Mw for new sources.

#Note: Assumes full annual costs of maintenance, chemicals, power, and labor. These costs would actually be less than shown and would reflect the extent of utilization of the plant.

Table A-VIII-26
Estimated Annual Costs
Recirculating Bottom Ash System
and Treatment of Combined Ash Pond Overflow*
(Retrofit Only)

Item	100 Mw ($1000)	1000 Mw ($1000)
Construction Cost (CC)	243.5	895.3
Total Capital Cost (TCC)	316.5	1,164.1
Maintenance @ 3% of CC	7.3	26.9
Fixed Charges @ 15% of TCC	47.5	175.0
Chemicals and Power	90.0	870.0
Labor	250.0	480.0
Total Annual Cost	394.8	1,559.9
Unit Cost		
Base-load (0.77 capacity factor)#	0.587	0.108
Cyclic (0.44 capacity factor)#	1.03	0.189
Peaking (0.09 capacity factor)#	5.02	0.923

* Note: Flow basis is 5,400 GPD/Mw

\# Note: Assumes full annual costs of maintenance, chemicals, power, and labor. These costs would actually be less than shown and would reflect the extent of utilization of the plant.

Reference 460 estimates the costs of settling ponds at $5,000/acre for 100 acre ponds and $1,000/acre for a pond of 2,400 acres. Reference 370 estimates that 300-400 acres of ash ponds (fly ash and bottom ash) would be required for a 3,000 Mw coal-fired plant. Assuming the above costs (0.5 scale factor on costs versus size) and a pond size of 12 acres/100 Mw and 120 acres/1000 Mw, the capital cost of an ash pond (fly ash and bottom ash) for a 100 Mw coal-fired plant would be $180,000 or $1.80/kw and $550,000 or $0.55/kw for a 1,000 Mw coal-fired plant. Assuming acreage for ponds handling only bottom ash to be 25% of the above and for fly ash 75% of the above, bottom ash ponds would cost $90,000 or $0.90/kw for a 100 Mw plant and $280,000 or $0.28/kw for a 1,000 Mw plant; and fly ash ponds would cost $150,000 or $1.50/kw for a 100 Mw plant and $480,000 or $0.48/kw for a 1,000 Mw plant.

Dry fly ash systems costs would vary from case to case depending on the quantities of ash transported and other factors. Cost have been reported of $150,000 for a 400-600 Mw plant handling 80 tons/hour and $500,000 for a 700 Mw plant handling 150 tons/hour.[449] Both costs do not include storage silos which may cost approximately as much as the other parts of the system. Both costs are for retrofitted systems and include equipment only. For the 700 Mw case above, the total capital costs is estimated to be $2,210,000 including 50% installation; 20% instrumentation, 15% engineering, and 15 % contingency costs. Applying a 0.6 scale factor, total capital costs for a new 100 Mw unit would be about $550,000 or $5.50/kw and $2,600,000 or $0.26/kw for a new 1,000 Mw unit. Estimated costs for retrofit systems would be more if a 100% factor for installation costs were used.

The use of recirculation bottom ash systems for all sources, dry fly ash systems for new sources, and primary sedimentation of fly ash for existing sources is estimated to achieve the removal of approximately 28,000,000,000 lb/year, by 1990, of total suspended solids that would have otherwise been discharged (over 99% removal). This estimate is based on the following assumptions:

- 33% of coal-fired generation would have used dry fly ash systems (base-line)
- 72% of coal-fired generation would have used ash ponds (base-line)

- 26% of coal-fired generation would have discharged directly (base-line)
- 2% of coal-fired generation would have discharged to sewers (base-line)
- 1990 coal-fired generation is 330,000 Mw
- Capacity factor 1990 coal-fired generation is 0.6
- In 1990, 67% of coal-fired generation will use dry fly ash systems
- In 1990, 1% of coal-fired generation will discharge to sewers
- In 1990, 0% of coal-fired generation will discharge directly
- Ash generated by a 1,000 Mw coal-fired plant (0.6 capacity factor) is 900,000 lb/day fly ash and 300,000 lb/day bottom ash
- Overflow from primary sedimentation of fly ash at a 1,000 Mw coal-fired plant (0.6 capacity factor) contains 700 lb/day of solids
- Discharges of solids from a treated recirculating bottom ash system at a 1,000 Mw coal-fired plant (0.6 capacity factor) are about 60 lb/day.

Costs for Complete Treatment of Chemical Wastes for Reuse

Because of the wide range of opportunities and associated incremental costs of achieving no discharge of pollutants from waste water sources other than cooling water systems and rainfall run-off (based on the technology of maximum recycle with evaporation of the final effluent) a model plant is employed as a basis for considerations of this higher level of technology. The features of the model plant are selected to produce conservatively high incremental costs of applying this technology, i.e. the determined costs would be at a level higher than would be expected for almost all other plants. The model plant would have such adverse characteristics that recycle of all water (except that used in ash sluicing systems or in wet-scrubber air pollution control systems) would not be practicable except after distillation. Distillation is much more costly than the chemical addition and sedimentation treatments which would be used in most cases. Ash sluicing water and wet-scrubber water would be recycled after sedimentation (or filtration) for solids removal. The model plant would have to distill blowdown from ash sluicing for recycle to other processes, however, the quantities of water distilled would be less than the feed intake to the system of low quality waste waters from other sources by the amount of evaporation during sluicing and the amount of moisture removed in the ash. Therefore, the assumption of the presence of wet ash sluicing is consistent with the conservative approach of the cost analysis. Similar considerations pertain to wet-scrubber air pollution control systems. Non-solar evaporation is further assumed.

Conceptual flow diagrams have been developed for such plans for coal-fired and oil-fired powerplants. These flow diagrams are shown in Figures A-VIII-11 and A-VIII-12. Cost estimates were then prepared based on these flow diagrams.

The three major process units required to provide a complete treatment of chemical wastes for reuse within a powerplant include a softener and chemical feed system to reduce the hardness of the cooling tower blowdown, a brine concentrator to preconcentrate the blowdown brines resulting from the recirculating of ash sluicing water, and an evaporator-dryer to finally reduce the sludge to a solid cake for disposal by landfill.

The capital costs, operating costs, and annual and unit costs for a complete treatment system for chemical wastes exclusive of once-through cooling water and rainfall runoff are estimated to be as follows:

- Capital cost, 3-6 $/kw
- Operating costs, 1 $/yr-kw
- Annual costs, 1-3 $/yr-kw
- Unit costs, 0.2-0.5 mill/kwh (base-load)

This system will produce no discharge of pollutants while returning the water to the process for reuse. The costs represent upper limits of cost. At some plants it may not be necessary to concentrate brine and evaporate to dryness. For example, plants in the southwestern United States would probably be able to utilize evaporation ponds at a substantial saving in cost. Mine-mouth plants will frequently have requirements for large volumes of low quality water for coal processing with ultimate disposal to

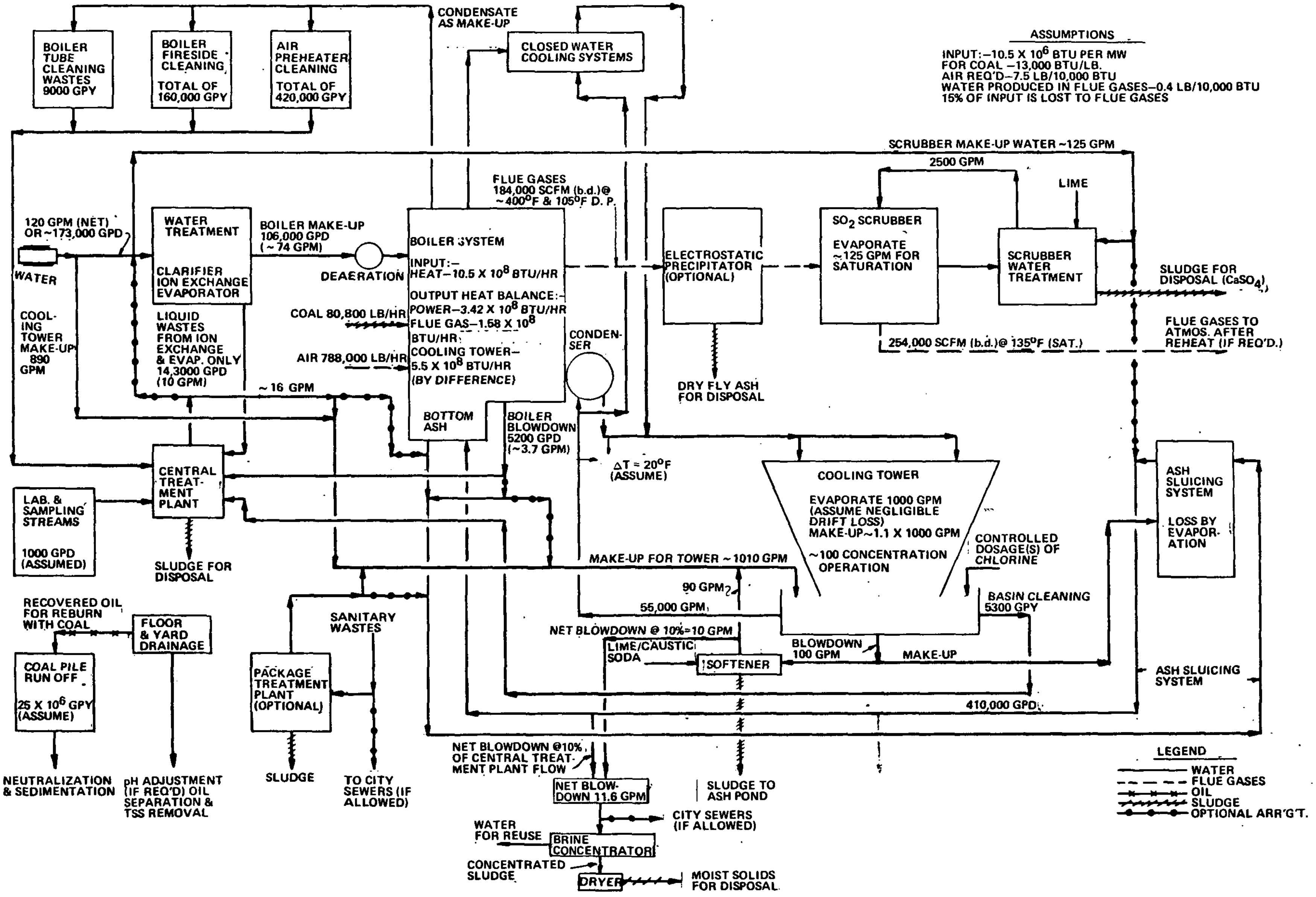


FIGURE A-VIII-11 100 MW COAL-FIRED STEAM ELECTRIC POWERPLANT RECYCLE AND REUSE OF CHEMICAL WASTES

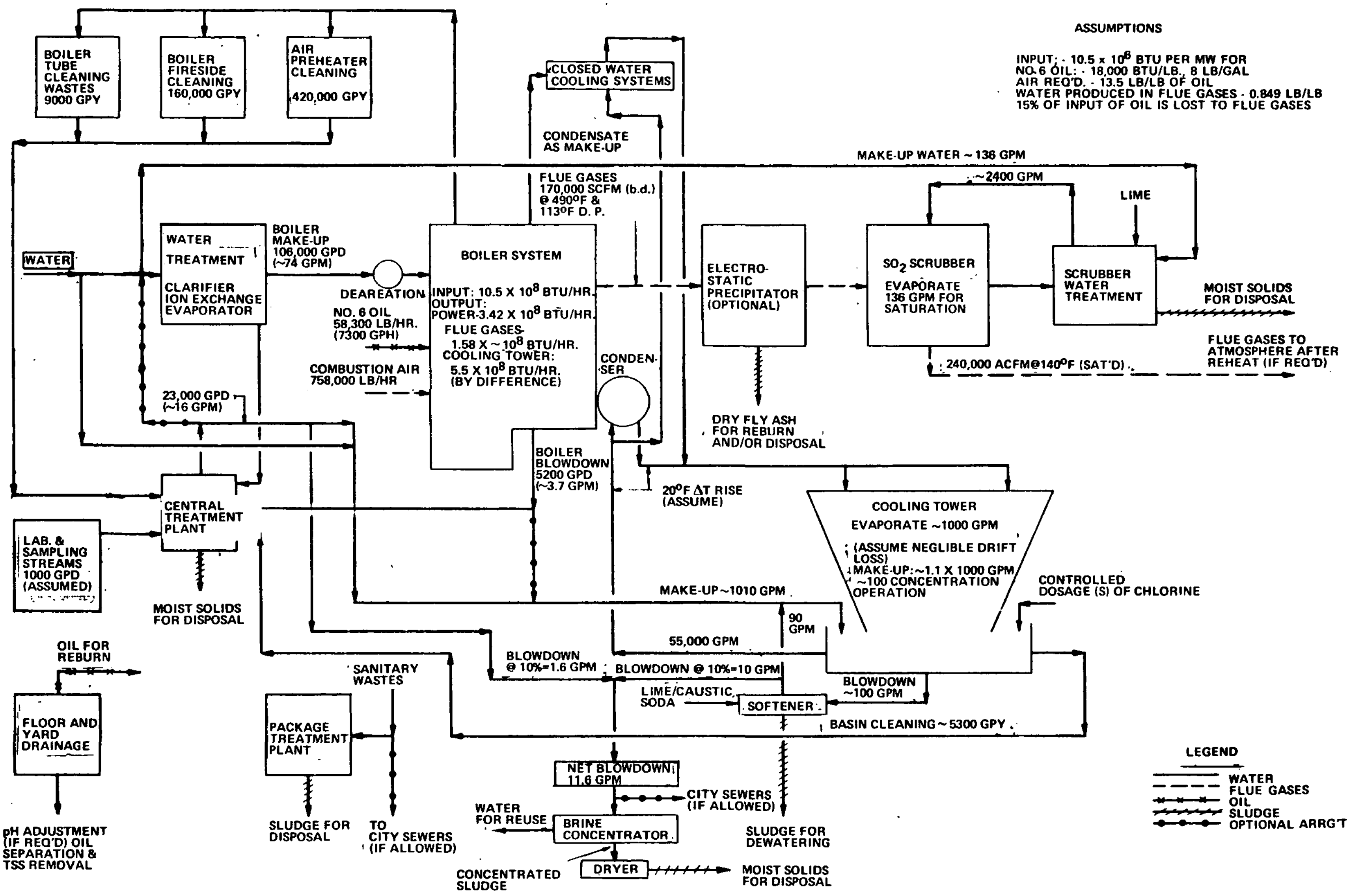


FIGURE A-VIII- 12 100 MW OIL-FIRED STEAM ELECTRIC POWERPLANT RECYCLE AND REUSE OF CHEMICAL WASTES the mine. The estimates assume that no alternate ultimate disposal methods for the brines are available and that evaporation to dryness is the only feasible method of ultimate disposal. Under these assumptions, the cost of complete treatment is estimated to be 0.30 mills per kwh for a 100 Mw plant and 0.11 mills per kwh for a 1,000 Mw plant assuming a unity capacity factor. For a typical base load plant operating at a capacity factor of 0.67, these costs increase to 0.45 mills per kwh for a 100 Mw plant and 0.17 mills per kwh for a 1,000 Mw plant. Costs for plants operated in the cycling mode at a capacity factor of 0.35 are about 0.86 mills per kwh for a 1000 Mw plant and 0.32 mills per kwh for a 100 Mw plant. Costs for a 100 Mw peaking plant are about 1.5 mills per kilwatt hour. These costs are about 5, 6, and 12 percent of production costs, respectively. The above costs assume the full capacity costs of maintenance, labor, chemicals, and power. The actual costs for these items would be lower than shown and would reflect the degree of utilization of the plant. Costs for smaller plants would be generally higher and costs for larger plants would be generally lower. Costs would be less for plants in climates suitable for solar evaporation. Cost would be generally less for nuclear plants and for gas-fired plants because there is no requirement for water related to ash handling. From an overall standpoint, costs would be generally lower than the costs for the model plant due to the conservative assumptions employed in the model. Full recycle of blowdown from evaporative recirculating cooling water systems would be significantly more costly. The costs of achieving no discharge of pollutants other than heat by complete chemical treatment and recycle provide a conservatively high estimate of achieving no discharge of pollutants from low-volume waste sources only.

Energy

Energy requirements for the treatment of chemical wastes are not a significant consideration. Most of the processes utilized for the treatment of chemical wastes require no input of energy other than that required for conveying the liquid. Some of the processes involved in the technology for achieving no discharge of pollutants involve a change of state from the liquid phase to the vapor phase, and others such as vacuum filters and reverse osmosis require substantial mechanical energy. However, these processes are generally applied to only a small portion of the total wastes, so that again the overall effect is negligible. Based on the flow diagrams for a central chemical wastes treatment plant and for complete treatment facilities designed to achieve no discharge of pollutants, the estimated energy requirements for central waste treatment are less than 10 kw per 100,000 kw of plant capacity, or less than 0.01% of the plant output. For complete treatment and reuse, including steam evaporation to dry material for ultimate disposal, the energy requirements are less than 0.2% of the plant output. For plants capable of achieving no discharge by utilizing evaporation ponds, energy requirements are about 0.04% of the plant output.

Non-Water Quality Environmental Impacts

The waste treatment processes previously discussed are essentially separation techniques which produce a liquid fraction suitable for discharge or reuse and a liquid-solid residue which requires ultimate disposal. The residues from ion exchange, evaporation, and reverse osmosis processes are concentrated brines, which carry the solids in solution form. The residues from other waste treatment processes are sludges of various types and concentration, which may contain from 0.5 to 5.0 % solids in the suspended form. The ease with which these sludges can be further dewatered depends on the type of sludge. At one end of the scale are sludges which contain a high proportion of mineral solids, and which dewater readily to about 20% solids. At the other end of the scale are gelatinous sludges such as those resulting from alum coagulation which are very difficult to dewater. The following paragraphs describe some of the dewatering and ultimate disposal techniques applicable to steam electric powerplants.

Intermediate Dewatering Devices

A number of devices are available for the intermediate dewatering of sludges from their original concentration of 1-5% solids to about 15-30% solids. These devices include vacuum filters, pressure filters and centrifuges.

Vacuum filters are devices consisting of a drum covered by a filter media and rotating slowly while partially submerged in a reservoir containing the sludge to be dewatered. A vacuum of 40 to 80 kN/sq m (12 to 25 in. of Hg) is applied to the inside of the drum, causing a layer of sludge to adhere to the surface of the media. As the layer emerges from the reservoir, it is further dried by air being drawn through the layer and into the interior of the drum. Just prior to resubmerging into the reservoir, the dewatered sludge is removed from the drum by a scraper and conveyed to disposal.

Some sludges contain very fine or filamentous solids that clog the filter media and prevent the flow of liquid and air through the media. Such sludges must be treated to increase the porosity of the filter cake. Treatments prior to filtration may consist of the addition of ferric chloride to colloidal sludges or diatomaceous earth to sludges containing a high proportion of silty material.[182]

Pressure filters are similar to vacuum filters except that the sludge or suspension is forced through the filter media by pressure rather than by vacuum. The most common filter media arrangement consists of a series of vertical frames covered by a cloth media. The sludge is applied through a header to the outside of the filter media, while the filtrate is collected from the inside. A filter aid is commonly used to increase the filterability of the sludges.

Neither vacuum filters nor pressure filters have been used for pollution control in steam electric powerplants to any significant extent, although certain types of pressure filters are used in some forms of condensate polishing.

Centrifuges are intermediate dewatering devices which make use of the gravitational forces in liquids rotating at high speeds to separate particulate matter from suspensions. There are no known instances of centrifuges being used by steam electric powerplants for pollution control, but the technology is available and should be considered as a means of concentrating and dewatering sludges.

Evaporation Ponds (Lagoons)

Evaporation ponds are a feasible method of ultimate disposal for plants having the necessary land area available and having climatic conditions favorable to this method. In general, annual evaporation should exceed annual rainfall by over 50 cm (20 in). This would restrict uncovered evaporation ponds to the southwestern portion of the United States.

Ponds are generally lined to prevent seepage into the ground. Multiple ponds are usually provided to allow evaporation from one pond while other ponds are receiving wastes. Facilities must also be provided to remove solids accumulated in the pond.

Landfill

Landfills are the most common method of disposal of solid residues. However, leachate from chemical wastes deposited in landfills may cause groundwater problems. If the wastes contain soluble components, fill areas must be lined and leachate and runoff collected and treated as for coal pile runoff.

Conveyance to Off-Site Disposal

Conveying brines and sludges to off-site disposal facilities is a method of ultimate disposal provided that the wastes have been concentrated to make conveying economically attractive and provided there is a facility to which the wastes can be delivered. Alternate methods of conveyance are by trucks, railroad cars or pipeline. Pipeline conveyance is the most economical means for quantities in excess of 100 cu m (26,000 gal) per day. For smaller quantities, truck or rail hauling is more economical, with distance the deciding factor. Trucking is more economical for distances below 50 km (35 miles) with rail haul more economical for longer distances. In any case, costs are of the order of $0.01 - 0.10 per cu m-km ($0.05 - $0.50 per 1000 gal - mile) exclusive of disposal charges by the receiving agency.[369] These costs are sufficiently high to make conveyance economically unattractive except at sites having no alternate means of disposal.

PART A

CHEMICAL WASTES

SECTIONS IX, X, XI

BEST PRACTICABLE CONTROL TECHNOLOGY CURRENTLY AVAILABLE, GUIDELINES AND LIMITATIONS
BEST AVAILABLE TECHNOLOGY ECONOMICALLY ACHIEVABLE, GUIDELINES AND LIMITATIONS
NEW SOURCE PERFORMANCE STANDARDS AND PRETREATMENT STANDARDS

Best Practicable Control Technology Currently Available

Cooling Systems

Free available chlorine discharges in both recirculating and nonrecirculating cooling water systems are to be limited to average quantities reflecting concentrations of 0.2 mg/l during a maximum of 2-hours a day (aggregate) and maximum quantities, during these periods, reflecting concentrations of 0.5 mg/l. These limitations can be achieved by means of available feedback control systems presently in wide use in other applications. Chlorination for biological control can be applied intermittently and thus should not be applied on two or more units at the same plant simultaneously in order to minimize the maximum concentration of total residual chlorine at any time in the combined cooling water discharged from the plant. Generally chlorination is not required at higher chlorine levels or for more than two hours each day for each unit. However, additional chlorination may be allowed in specific cases to maintain tube cleanliness. Alternative methods of reducing the total residual chlorine in condenser cooling water systems include chemical treatment, substitution of other less harmful chemicals, and use of mechanical means of cleaning condenser tubes. Mechanical cleaning is employed in some plants but its practicability depends on the configuration of the process piping and structures involved at the particular unit. Moreover, chlorine may still be discharged even with mechanical cleaning of condenser tubes, because of its continued use in maintaining biological control in other parts of the cooling system. Further removal of residual chlorine in nonrecirculating condenser cooling water systems by chemical treatment is available but is not generally practicable because of the additional costs involved to treat the large volumes of water involved.

Chemical treatment of recirculating cooling water systems would be less costly and the pollution potential of residual bisulfide chemicals added would be less significant than with nonrecirculating cooling water systems due to the smaller wastes water volumes requiring treatment. Experience in this technology is highly limited in the powerplant field; however, this is a well established technology in the water supply industry. Other technologies potentially available for recirculating cooling water systems are split stream chlorination, blowdown retention, and intermittent discharge programmed with intermittent chlorination.

The use of chemicals for control of biological growth, scaling and corrosion in evaporative cooling towers is commonplace. The types and amounts of chemicals required is highly site-dependent. Chromate addition is not generally required for corrosion control. Phosphates and zinc salts are employed in some cases. Insufficient data exists to judge what alternative chemicals for control of corrosion, etc., would be generally practicable from a cost versus effluent reduction benefit standpoint. Minimum discharge of added chemicals can be achieved by employing the best practicable technology for water treatment and water chemistry to minimize the quantities of blowdown flow required. In cases of new sources, design for corrosion protection can eliminate the need for chemical additives for corrosion protection. Treatment of cooling tower blowdown by chemical addition for effluent pH control, and by sedimentation for reduction of effluent total suspended solids is achievable, however, essentially all total suspended solids that would be removed would come from sources other than the process (intake water and air).

Low-Volume Waste Waters

Low-volume waste water sources include boiler blowdown, ion exchange water treatment, water treatment evaporative blowdown, boiler and air heater cleaning, other equipment cleaning, laboratory and sampling streams, floor drainage, cooling tower basin cleaning, blowdown from recirculating ash sluicing systems, blowdown from recirculating wet-scrubber air pollution control systems, and other relatively low volume streams. These wastes, where by the specific waste water parameters of the untreated waste, can be practicably treated collectively by segregation from higher volume wastes, equalization, oil separation, chemical addition, solids separation, and pH adjustment.

Oily streams such as waste waters from boiler fireside cleaning, air preheater cleaning and miscellaneous equipment and stack cleaning would be practicably treated for separation of oil and grease, if needed, to a daily average level of 15 mg/l. Addition of sufficient chemicals to attain a pH level in the range 9 to 10 and total suspended solids of 30 mg/l in the effluent of this treatment stage would be generally practicable considering the pH levels of the untreated waste streams and the waste water flow volumes involved. Generally, the higher the pH level, with total suspended solids of 30 mg/l, the greater the effluent reduction benefits attained for the numerous chemicals removed by treatment. Examples of pollutants significantly reduced by this treatment are the following: acidity, aluminum, biochemical oxygen demand, copper, fluoride, iron, zinc, lead, magnesium, manganese, mercury, oil and grease, total chromates, total phosphorous, total suspended solids, and turbidity. Some waste water characteristics, such as alkalinity, total dissolved solids, and total hardness are increased, however. Following the above treatment it would be practicable, in a second stage, to adjust the effluent pH to a level in the range 6.0 to 9.0 in compliance with stream standards, with sedimentation to attain final daily average effluent total suspended solids levels of 30 mg/l. Effluent daily average concentrations of levels of 1 mg/l total copper and 1 mg/l total iron are achievable by the application of this technology to segregated metal equipment cleaning waste waters and to segregated boiler blowdown. The effluent limitations in mass units, in any particular plant, would be the products of the collective flow of the affected low-volume waste sources times the respective concentration levels.

Segregation and treatment of boiler cleaning waste water and ion exchange water treatment waste water is practiced in a relatively few plants, but some degree of segregation is potentially practicable for all plants. Oily waste waters are segregated from non-oily waste streams at some plants and the oil and grease removed by gravity separators and flotation units.

Combined treatment of waste water streams is practiced in numerous plants. However, in most cases treatment is accomplished only to the extent that self-neutralization, coprecipitation and sedimentation occur because of the joining and detention of the waste water streams. Chemicals are added during combined treatment at some plants for pH control. Most of these plants employ lagoons, or ash ponds, while a few plants employ configured settling tanks.

Separate regulations are now being formulated by EPA to set forth effluent limitations for sanitary waste waters from privately-owned treatment works such as would be the case for sanitary waste treatment for steam electric powerplants.

Once-Through Ash and Air Pollution Control Systems

Daily average effluent total suspended solids levels of 30 mg/l are practicably attainable as are oil and grease levels of 15 mg/ and pH values in the range 6.0 to 9.0. Due to the fact that intake water to ash sluicing and air pollution control systems is often well in excess of this level, an effluent limitation of 30 mg/l total suspended solids times the waste water flow would, in many of those cases, require the removal of quantities of suspended solids not added by the plant. In the light of this, in cases where it is authorized to take account of suspended solids not added by the plant, it should be practicable for an effluent total suspended solids level for these streams to be limited to a greater number of pounds per day but not in excess of the total intake to the plant for these systems.

Dry processes are used by most oil-fired plants for ash handling, while only fly ash is handled dry at some coal-fired plants. Gas-fired plants have little or no ash. The extent of the practicability of employing dry processes for bottom ash handling at coal-fired plants is not known.

Rainfall Runoff Waste Water Sources

Rainfall run-off waste water sources include materials storage drainage and run-off from construction activities. Construction activities include only those in the immediately vicinity of the generating unit (s) and related equipment. Runoff from other parts of the site (land for future generating units, construction of access roads, cooling ponds and lakes, visitor centers, etc.) is not intended to be covered by this limitation. Effluent limitations of 50 mg/l total suspended solids and a pH value in the range 6.0 to 9.0 reflect the technology of diking, neutralization, and solids separation.

Best Available Technology Economically Achievable

The technology of re-use and recycle of all waste water to the maximum practicable extent, with distillation to concentrate all low-volume water wastes and to recycle water to the process, and with evaporation to dryness of the concentrated waste followed by suitable land disposal is not judged to be generally warranted due to the finding that the technology has not been fully demonstrated.

Re-use of waste water streams is practiced at relatively few plants, but some employ recycle of ash sluice water. Distillation concentration with recycle is currently planned for at least three plants. Some stations plan to employ re-use of cooling tower blowdown in wet-scrubber air pollution control systems. Since water quality requirements for bottom ash sluicing operations and are relatively low, some degree of re-use should be practicable for all plants where these operations are employed. Best available technology economically achievable is reflected by retrofit systems for the recycle of bottom ash transport water with a resulting blowdown flow of 8 percent of the volume of ash transport water treated by sedimentation to a total suspended solids level of 30 mg/l, an oil and grease level of 15 mg/l and a pH value in the range 6.0 to 9.0. Universal retrofitting of dry fly ash systems would not be economically achievable. The concept of cascading water use, i.e., recycle and re-use of water from applications requiring high quality water to applications requiring successively lower water quality, to reduce to the volume of waste water, if any, ultimately requiring evaporation or other treatment, while practicable in all cases, would generally be subject to a case-by-case analysis to determine the optimum among the various candidate systems.

Chemical treatment of blowdown from recirculating cooling water system for removal of total chromium, total phosphorus (as P) and zinc, while not currently demonstrated in powerplant applications, could be achieved by 1983, in the relatively small number of cases where it would be needed. Corresponding effluent limitations, based on the application of this technology, are 0.2 mg/l total chromium, 5 mg/l total phosphorus (as P), and 1 mg/l zinc-total, all times the waste water flow.

Chlorination programs to achieve no discharge of total residual chlorine from recirculating cooling water systems have been determined to be not fully demonstrated and therefore cannot be generally applied by 1983.

Rainfall runoff limitations are the same as best practicable control technology currently available.

New Source Performance Standards

In view of the current technical risks associated with the application of distillation technology to waste water recycle and chlorination programs to achieve no discharge of total residual chlorine from recirculating cooling water systems, new source performance standards have been determined to be identical to the limitations prescribed for best available control technology economically acheivable with the following exceptions. Recirculating bottom ash transport systems designed for new sources can reasonably achieve effluent limitations based on a blowdown flow of 5 percent of the ash transport flow volume. No discharge is allowed of corrosion inhibitors in blowdown from recirculating evaporative cooling water system, based on the availability of design technology for corrosion prevention. No discharge of pollutants from nonrecirculating ash sluicing system, based on the general availability of dry fly ash systems and of recirculating wet bottom ash systems.

Rainfall runoff limitations are the same as best practicable control technology currently available.

Application of Effluent Limitations Guidelines and Standards

The effluent limitations for a powerplant are determined based on the existing or planned flow rates of the individual waste sources at the plant and the effluent limitations corresponding to each of the waste sources. An example is given in Figure A-X-1 and Table A-X-1 of the determination of the effluent limitation for a simplified hypothetical case. The extent of the feasibility of the flow arrangement shown is not known and is presented solely as an example of the application of the effluent limitations guidelines and standards. For the plant shown, the determination of the limitations, for the metal equipment cleaning wastes is straight-forward since there is no reuse or combination with other wastes prior to treatment, except that the waste waters are combined with other wastes waters immediately prior to discharge. Boiler blowdown, however, is combined with other waste waters prior to treatment, as is ash transport water and some of the waste water from other low-volume wastes sources. Some of the cooling tower blowdown and some of the waste waters from other low-volume waste sources are reused directly for ash transport. A portion of the overflow of the first stage (ash pond) of the combined treatment of ash transport water, boiler blowdown, and wastes from other low-volume waste sources is recycled for use in bottom ash transport. The remainder of the ash pond overflow receives final treatment prior to being combined with treated metal equipment cleaning waste waters and some of the cooling tower blowdown prior to discharge.

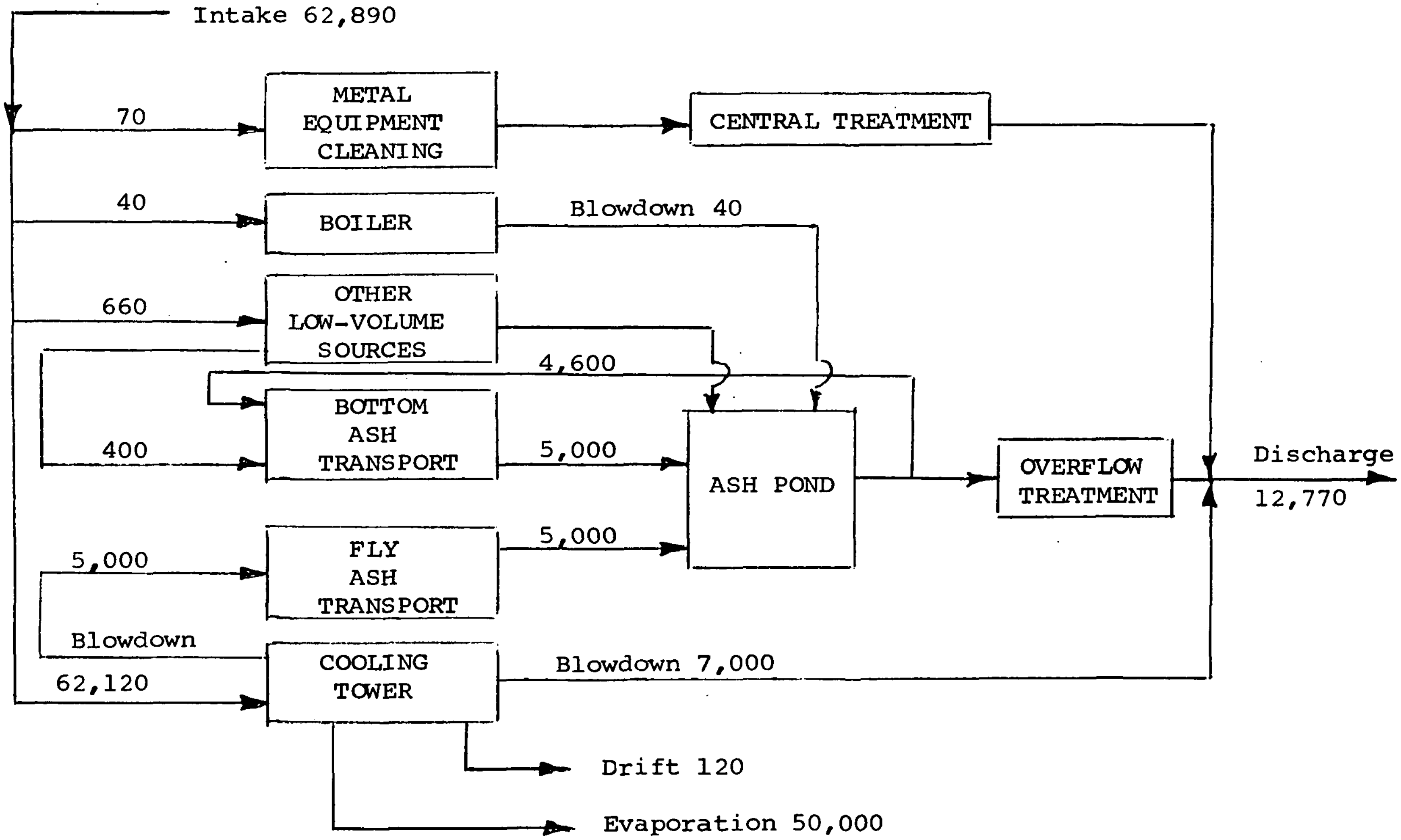


Figure A-X-1 Hypothetical Powerplant Water Flows
(Flows shown in units of 1000 liters/day)

Table A-X-1

Effluent Limitations for Hypothetical Powerplant

Source	Flow, 1000 l/day	Effluent Limitations, kg/day						
		TSS	Fe	Cu	Zn	Cr	P	O&G
Metal Equipment Cleaning	70	2.1 (30)*	0.07 (1)	0.07 (1)	N	N	N	1.05 (15)
Boiler Blowdown	40	1.2 (30)	0.04 (1)	0.04 (1)	N	N	N	0.60 (15)
Other Low-Volume Sources	660	19.8 (30)	N	N	N	N	N	9.9 (15)
Bottom Ash Transport	5,000	12.0 (30/12.5)	N	N	N	N	N	6.0 (15)
Fly Ash Transport	5,000	150.0 (30)	N	N	N	N	N	75.0 (15)
Cooling Tower Blowdown	12,000	N	N	N	12.0 (1)	2.4 (0.2)	60.0 (5)	N
Total		185.1+	0.11+	0.11+	12.0+	2.4+	60.0+	92.55+

* Note: Concentration bases, mg/l, shown in parentheses
\+ Note: Plus effluent from sources with no limitation

In each case, the effluent limitations for a particular waste water source are based on the wastewater flow emanating from that source, regardless of the subsequent reuse, recycling, or combination of the wastewater with other streams, and regardless of the source of the water used by that source. A discharger may find that the reuse of certain waste streams results in a less costly pollutant removal scheme than one employing no reuse due to the reduction in the final flow volume requiring treatment. Water reuse may also be employed to reduce the volume of water required by the plant or to reduce the cost of influent water treatment.

In no case, however, should the effluent limitations computed for a plant which combines waste water streams reflect effluent reductions (mass units) less than would be achieved by the same plant in the case that the individual limited waste water streams are not combined with other waste water streams that are or are not limited. Within the context of the above, effluent limitations computed for the plant should not reflect the transfer from individual limited waste water streams, whose limitations are based on chemical precipitation and sedimentation technology, of pollutants (other than pH) that would otherwise be removed by chemical precipitation and sedimentation to other waste water streams that have no limitations which reflect chemical precipitation and sedimentation technology.

If other regulations permit allowances to be made for pollutants brought into the plant in make-up waters, no distinction should be made in the effluent limitations between inert suspended solids brought into the plant and inert suspended solids added by the plant. Suspended solids that are not inert, such as precipitated metals, should not be discharged in exchange for inert suspended solids in make-up water. The requirements can generally be met by the technology that provides the basis for the effluent limitations developed in this document since the limits developed are assumed to apply as gross limits.

For the purposes of estimating the costs of the application of available technology for the reduction of pollutants discharged from both continuous and intermittent waste sources, it is assumed that waste waters are discharged after treatment on a continuous and uniform basis year round. A discharger may find, however, that an alternative discharge schedule would be less costly or otherwise more desireable, in which case the effluent limitations should reflect the discharge flow volume program proposed by the discharger.

Costs

The incremental costs of controlled additions of chlorine, in the cases where chlorine is required for biological control, are less than 0.01 mill/kwh. In the relatively few cases where chromates are added for corrosion control and where other less harmful chemicals and methods can provide effective corrosion control the incremental costs are less than 0.01 mill per kilowatt hour. The incremental cost of mechanical cleaning to replace some fraction of the total required chlorine additives is approximately 0.01 mill/kwh for existing stations and considerably less for new units whether at new or existing plants.

Cost estimates based on the combined treatment of selected low-volume streams for oil and grease separation, equalization, chemical precipitation, solids separation, and further based on generalizations with respect to the cost of land, construction, site preparation and with respect to the waste water volume, indicate an approximate cost of 0.1 mill per kilowatt-hour depending upon the plant's generating capacity and utilization. The highest costs are associated with the smaller plants and peaking plants which generally have the highest basic generating cost. In general, the entire incremental cost should be felt by individual plants since this type of complete chemical treatment is not generally employed.

Sedimentation of ash sluicing water, etc., would cost typically about 7 cents/1000 gal, with the incremental cost in mills/kwh being related to the quantitites of water treated. Since many plants already have some type of sedimentation facility, the incremental costs of improved sedimentation performance if required will be some fraction of the cost cited.

In the few cases where it would be required chemical treatment for removal of phosphorus, total chromium or zinc from cooling tower blowdown would cost about 0.1 mill per kilowatt-hour. Incremental costs of dry ash handling systems for new sources are estimated to be less than 0.01 mill/kwh and would largely depend on the economics of dry ash disposal or sale versus wet ash disposal in specific cases.

Recirculating ash sluicing systems require sedimentation discussed above plus pumps, piping and a blowdown system. Incremental costs above sedimentation are approximately 0.1 mill/kwh for existing plants and considerably less for new plants.

The incremental costs of equipment design for corrosion protection are normally largely offset by other cost benefits such as reduced costs of chemicals. The net incremental costs for both lined cooling tower components and stainless steel or titanium condenser tubes would be less than 0.1 mill/kwh total. Replacement of existing cooling tower components might be more expensive however.

Energy and Other Non-Water Quality Environmental Impacts

Energy requirements for technologies reflecting the application of the best available technology economically achievable for pollutants other than heat are less than 0.2 percent of the total plant output.

The non-water quality impacts of technologies available to achieve limitations on pollutants other than heat are negligible with respect to air quality, noise, water consumption and aesthetics. Solid waste disposal problems associated with achieving the limits required by best practicable control technology currently available are similarly insignificant. Systems with evaporation and recycle of waste water will not generally create significant amounts of solid waste. If recycle of blowdown from evaporative recirculating cooling systems were to be employed, however, considerable volumes of solid waste may be generated. In most cases these are nonhazardous substances requiring only minimal custodial care. However, some constituents may be hazardous and may require special consideration. In order to ensure long term protection of the environment from these hazardous or harmful constituents, special consideration of disposal sites may be made. All landfill sites where such hazardous wastes are disposed should be selected so as to prevent horizontal and vertical migration of these contaminants to ground or surface waters. In cases where geologic conditions may not reasonably ensure this, adequate legal and mechanical precautions (e.g. impervious liners) should be taken to ensure long term protection to the environment from hazardous materials. Where appropriate the location of solid hazardous materials disposal sites should be permanently recorded in the appropriate office of legal jurisdiction.

PART B

THERMAL DISCHARGES

SECTION V

WASTE CHARACTERIZATION

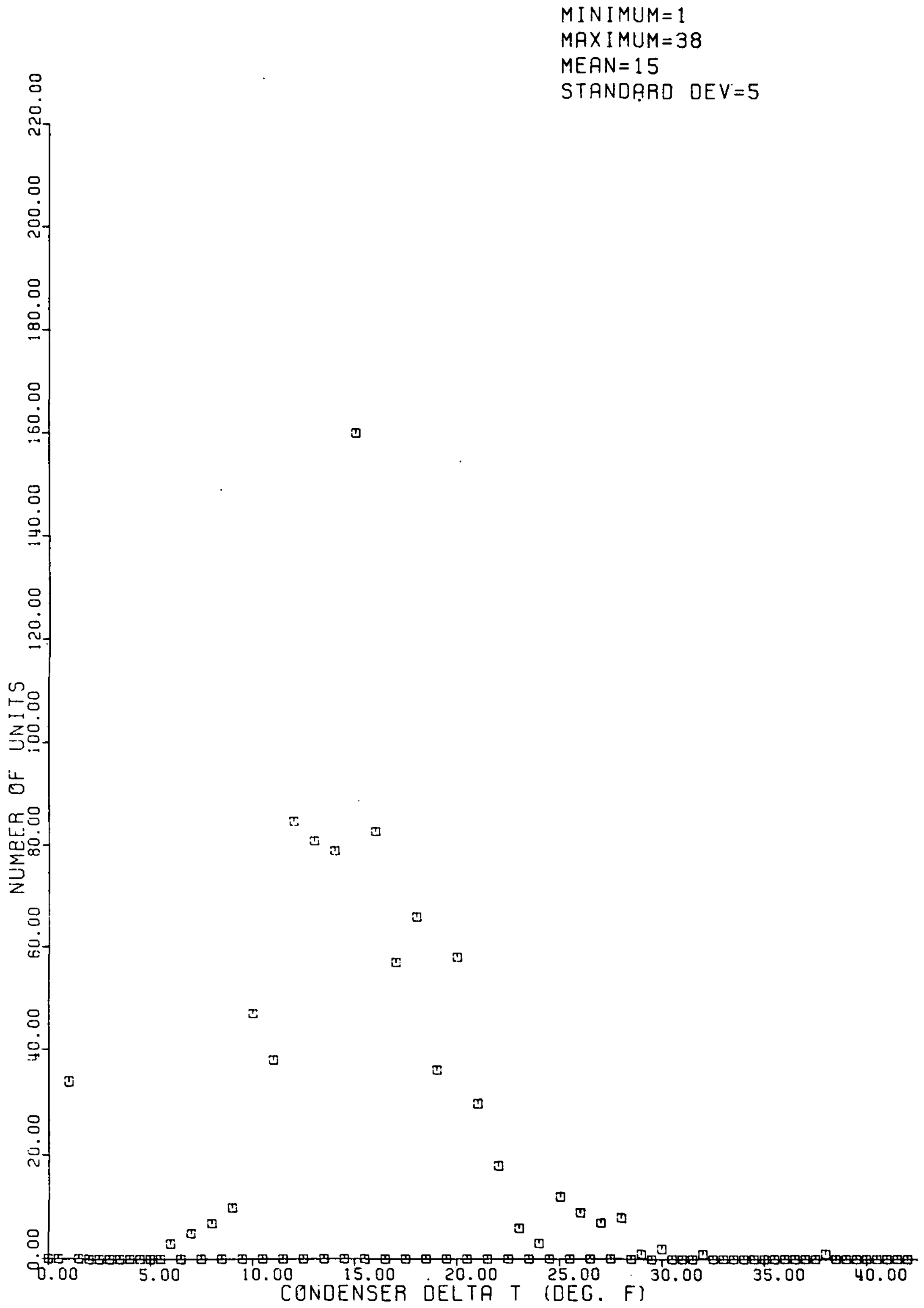
General

Significant thermal discharges from steam electric powerplants occur when a powerplant utilizes a once-through circulating water system to reject the heat not converted into electric energy. The amount of heat energy discharged with the circulating water is equal to the heat value of the fuel less the heat value converted into electric energy and miscellaneous station losses. The heat energy discharged is therefore directly related to the efficiency of the plant. According to industry practices, the efficiency of a generating unit is expressed as its heat rate, in units of Joules per kwh (Btu per kwh). A new fossil-fired generating unit may be designed for a heat rate of 9.5 million Joules per kwh (9,000 Btu/kwh). Since one kwh is equivalent to 3.6 million J/kwh (3,413 Btu), such a plant would have an efficiency of 38%.

The transfer of heat from the condensing steam to the cooling water results in a temperature rise of the cooling water. For a given amount of heat transfer, the temperature rise of the cooling water is inversely proportional to its flow. That is, one may either heat a small quantity of water a great deal, or a large quantity of water a small amount. On the average, temperature rises have been centered about 9 degrees C (16 degrees F) for economic and process considerations (Figure B-V-1). It is clear, however, that almost any lower limit on temperature rise can be achieved given a sufficiently large source of cooling water and no economic constraints. It is also clear, however, that a temperature difference reduction does not limit the amount of heat rejection.

Quantification of Waste Stream Characteristics

The data presented below were obtained from the Federal Power Commission and represent a summary of the data collected on "FPC Form 67" for the year 1969.[280] These data have been screened to eliminate obvious inconsistancies. The statistical analyses have been performed using standard subroutines available from IBM in their scientific subroutine package (1000) operating units. All units in



UNIT CONDENSER DELTA T

FIGURE B-V-1

this sample are fossilfueled. Heat rates for the industry are profiled in Figure B-V-2. This figure shows the mean unit heat rate to be approximately 11.8 million Joules/kwh (11,200 Btu/kwh) with a standard deviation of approximately 2.86 million Joules/ kwh (2,700 Btu/kwh). These statistics are not weighted by generation. Weighted figures show the national average heat rate to be about seven (7) percent lower.[281] Given the heat rate, one may calculate the cooling water heat rejection for fossil plants in the following manner:

1. Multiply the heat rate by the boiler efficiency (0.8-0.9 are reasonable efficiencies to use for this calculation)

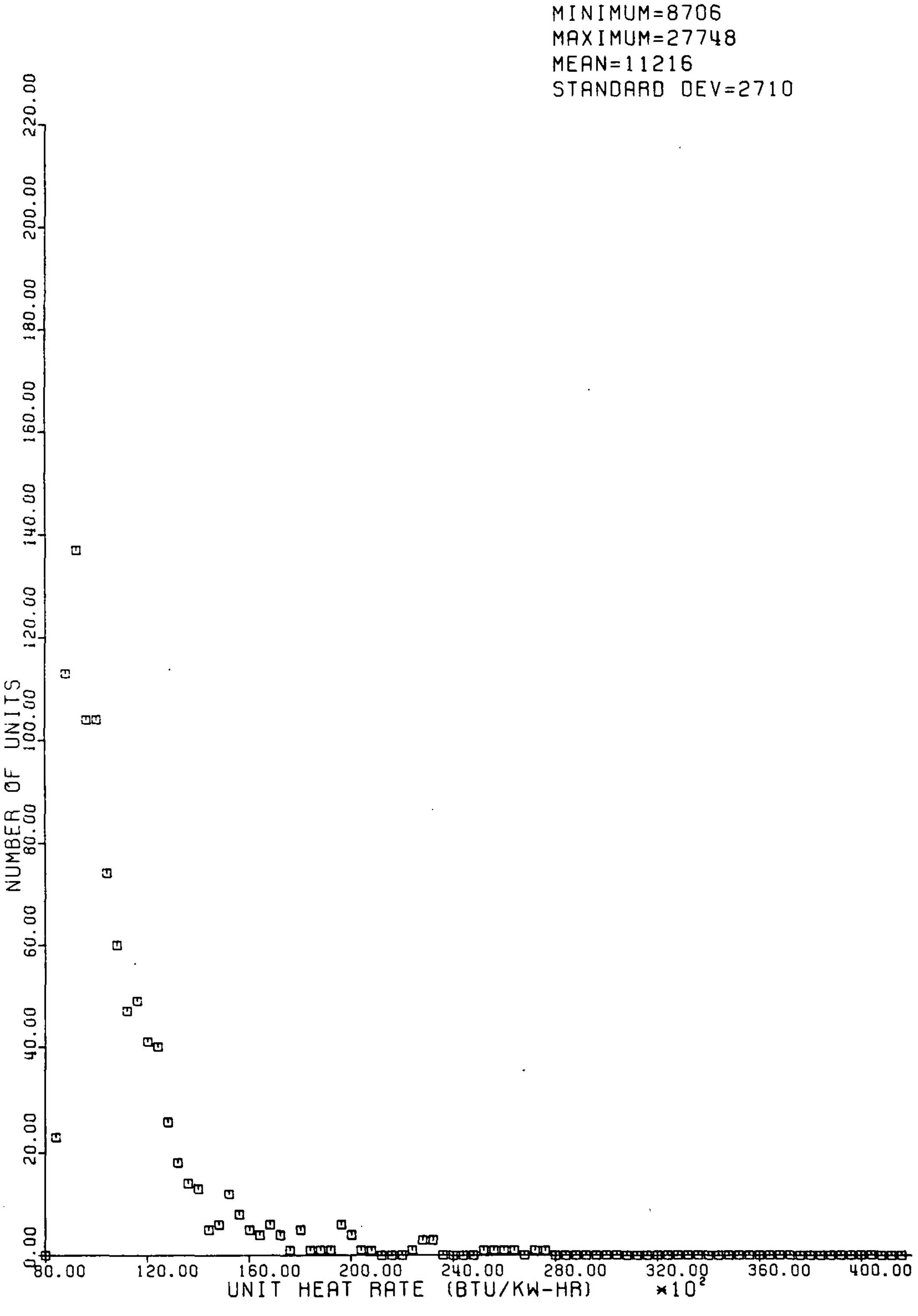
2. Subtract from that number the energy of one (1) kwh (3,600,000 Joules or 3,413 Btu).

3. The result is the heat rejected to the cooling water stream.

The result obtained from this calculation is slightly higher than the real requirement in most cases. This analysis ignores the difference between the lower and higher heating values of the fuel. Heat rates can be reported using high heating values although all this energy is not available to do work. The difference is lost forming water vapor from the hydrogen in the fuel and oxygen in the air. Various in-plant heat and steam losses, and the power requirements of the plant's auxilliary equipment are also ignored. Using this analysis, the mean plant in our sample rejects about seven (7) million Joules (6,640 Btu) per net kwh generated. Table B-V-1 lists heat rates, efficiencies, and waste heat produced for a range of plants typical of the industry. The heat rejection requirements calculated above are satisfied by the heating of the circulating water. Figure B-V-1 indicates that the mean temperature rise (unit basis, not weighted) of the cooling water is between eight and nine degrees C (about 15 degrees F) with a standard deviation of about three degrees C (5 degrees F).

Flow rates range from about 1,100 liter/min (300 gpm) to 4,000 liter/min (1,100 gpm) for each megawatt of load.[280] Thus a 100 Mw unit operating at capacity may discharge up to 400,000 liter/min (110,000 gpm) of water heated to nine degrees C (15-16 degrees F) above ambient. (A more typical number would be about two-thirds of this example based on national heat rates).

The maximum summertime temperature of the heated effluent varies with location, but is strongly centered (Figure B-V-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STANDARD DEV=2710
NUMBER OF UNITS
0.00
20.00
40.00
60.00
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140.00
160.00
180.00
200.00
220.00
80.00
120.00
160.00
200.00
240.00
280.00
320.00
360.00
400.00
UNIT HEAT RATE (BTU/KW-HR) ×10²
UNIT HEAT RATE DISTRIBUTION

FIGURE B-V-2

Table B-V-1

EFFICIENCIES, HEAT RATES AND HEAT REJECTED BY COOLING WATER

Plant Efficiency,	Plant Heat Rate	Heat Converted to Electricity	Stack and Plant Heat Losses	Heat Rejected to Cooling Water
%	Joules per kwh x 10^{-6} (Btu/kwh)			
	Fossil-Fueled Units			
38	9.5 (9,000)	3.6 (3,400)	0.95 (900)	4.95 (4,700)
34	10.5 (10,000)	3.6 (3,400)	1.05 (1,000)	5.85 (5,600)
29	12.5 (12,000)	3.6 (3,400)	1.25 (1,200)	7.65 (7,400)
23	15.5 (15,000)	3.6 (3,400)	1.55 (1,500)	10.35 (11,100)
17	21.0 (20,000)	3.6 (3,400)	2.1 (2,000)	15.3 (14,600)
	Nuclear Units			
34	10.5 (10,000)	3.6 (3,400)	0.5 (500)	6.4 (6,100)
29	12.5 (12,000)	3.6 (3,400)	0.6 (600)	8.3 (8,000)

3) about 35 degrees C (95 degrees F). It is interesting to note the large number of plants operating at or above a maximum summertime outfall temperature of 39 degrees C (102 degrees F). At elevated temperatures turbine efficiency frequently begins to suffer.

Table B-V-2 summarizes data received from powerplants visited under this contract. Many of the plants visited were among the most efficient in the nation.

The visits were, in general, made to examine unique features in control or efficiency incorporated in the plant. These data, therefore, represent typical values for newer modern plants rather than an industry-wide cross section. Of some interest, however, are the data from the nuclear plants visited. Since all nuclear plants in utility service are relatively new, these plants may be considered typical of nuclear plants. It is observed that the heat rejection is considerably higher for nuclear plants (by a factor of more than 1.5) than for the fossil-fueled plants studied. In addition, the temperature rise for the nuclear plants is generally higher.

Industry-Wide Variations

Heat rate varies about thirteen percent regionally.[281] This variation is due to relative equipment age, availability of high quality fuel, and economic and other factors. For example, the northeastern section of the country has many old, relatively inefficient units which must be operated to meet loading requirements. On the other hand, the western section of the country uses a great deal of lower heating-value lignite which contributes to its higher average heat rate. The southeastern section of the country can attribute its lower average heat rate to many new, large, efficient units burning high-quality fuel. The net effect of the regional heat rate variation on heat rejection requirements may be as high as twenty percent (see previous section for calculations). This number may be considered conservative, however, since some of the regional heat rate variation is fuel quality dependent.

Temperature rise varies with both heat rate and cooling water availability. In addition, considerations such as economics, ambient water temperature, and water quality requirements weigh heavily upon the design cooling water temperature rise. Thus, temperature rise requires a plant by plant evaluation.

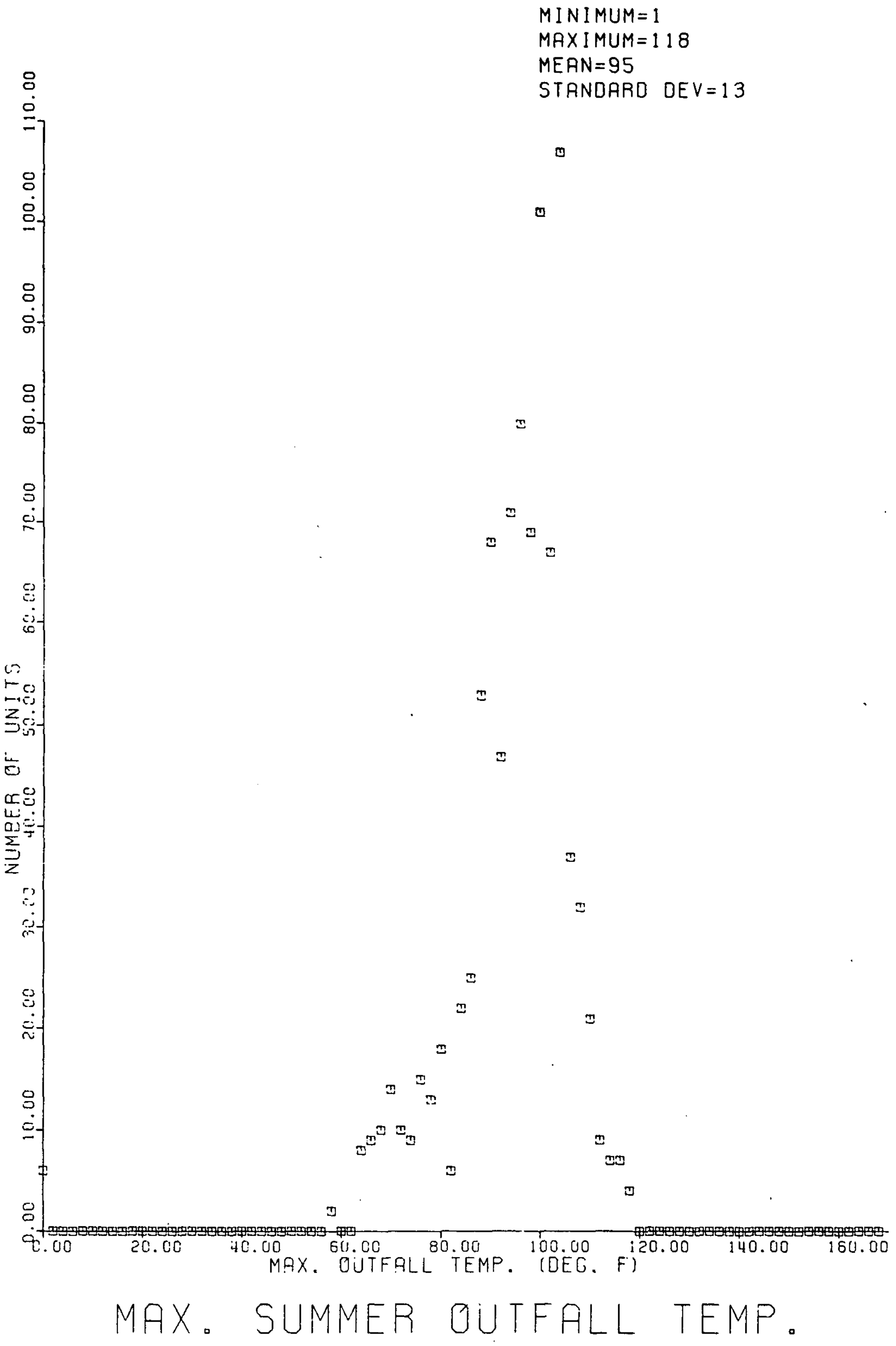

MINIMUM=1
MAXIMUM=118
MEAN=95
STANDARD DEV=13
NUMBER OF UNITS
0.00
10.00
20.00
30.00
40.00
50.00
60.00
70.00
80.00
90.00
100.00
110.00
0.00
20.00
40.00
60.00
80.00
100.00
120.00
140.00
160.00
MAX. OUTFALL TEMP. (DEG. F)
MAX. SUMMER OUTFALL TEMP.

FIGURE B-V-3

TABLE B-V-2

PLANT VISIT THERMAL DATA

Plant ID	Fuel	Capacity Mw	Heat Rate Joules/kwh X 10^{-7}	Cooling Water Flow M^3/min	Temp. Rise °C	Discharge Temp. °C Summer	Winter	Average	Heat Dissipation Joules/Hr X 10^{-9}	Joules/kwh X 10^{-6}
0640	Nuclear	916	N.A.	1688	15.6	30.0	27.0	28.3	6580	7.194
1209	Nuclear	1456	1.1	4735	8.9	40.6	28.9	35.6	10588	7.27
2612	Nuclear	700	1.1	1476	13.9	N.A.	N.A.	N.A.	5135	7.349
1723	Nuclear	1618	N.A.	3564	13.3	36.7	14.4	N.A.	11916	7.37
3117	Nuclear	457	1.07	1362	10.0	28.6	13.9	21.7	3417	7.48
1201	Oil & Gas	139.8	1.02	439	5.7	34.0	22.3	26.8	624.3	4.466
1201	Oil & Gas	792	N.A.	2002	8.5	39.6	29.1	32.4	4271	5.39
5105	Oil	1157	1.09	1851	13.2	45.4	18.2	36.3	6116	5.285
2525	Oil	1165	.95	2346	8.2	31.0	12.7	21.4	4840	4.156
0801	Coal & Gas	300	1.12	1056	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
1209	Coal & Gas	820	.99	2078	7.3	38.9	27.3	33.9	3786	4.626
4217	Coal	1640	1.03	2120	14.4	31.7	17.8	26.7	7676	4.68
4846	Coal	1150	1.05	2838	7.5	N.A.	N.A.	N.A.	5336	4.645
3713	Coal	2137	.92	3883	10.0	28.3	17.8	N.A.	9744	4.56
2512	Oil	542.5	.94	632	16.1	33.4	22.6	28.0	2552	4.71
3115	Oil & Gas	644.7	1.06	1429	9.3	28.2	13.2	21.0	3343	5.196
2527	Oil	28	1.02	94.6	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
0610	Oil & Gas	750	1.15	1332	10.0	36.7	20.0	26.7	3343	4.46
2119	Coal	2534	N.A.	2937	13.9	N.A.	N.A.	N.A.	10229	4.04
Nuclear Averages			1.09	N/A	12.34	N/A	N/A	N/A	N/A	7.33
Fossil Averages			1.03	N/A	10.34	N/A	N/A	N/A	N/A	4.68

N.A. - Not Available

N/A - Not Applicable

Maximum temperature of the outfall varies with both ambient temperatures and temperature rise. Thus higher temperatures should be expected in the southern section of the country. This expectation is somewhat mitigated by the fact that the steam cycle has efficiency limitations beyond certain temperatures. Thus, utilities economically optimize temperature rise (a lower temperature rise requires more pumping power and/or a larger condenser) and final temperature (a higher final temperature reduces turbine efficiency). Therefore, regional variations in maximum summertime outfall temperature are not as large as regional variations in ambient water temperatures.

Seasonal variations in heat rate, temperature rise and outfall temperature may be significant but move in opposing directions. That is, when the ambient temperature, the maximum outfall temperature and the heat rate increase, the temperature rise, in general, falls. In many sections of the country, the summer heat rate is higher than the winter heat rate because many inefficient peaking plants are run only in the summer months. This effect is in addition to the efficiency loss created by ambient conditions. The efficiency loss is of particular concern since peak demand usually coincides with the worst (for power generation) ambient conditions, which can cause power shortages. Conversely, the wintertime heat rate (usually better than summer) occurs at a time when demand is below peak. Therefore, the heat rejected per kwh, the total heat rejected, and the maximum outfall temperature are all lower. While the temperature rise may be higher in the winter, it can be controlled by increasing the cooling water flow (which was cut back for economic reasons to cause the higher rise in the first place).

Age is a frequently mentioned parameter for the thermal effluent of powerplants. Historically, plant aging has been a double edged sword. The aging process included material and equipment deterioration (turbine blade erosion, etc.) which is an absolute loss over a period of time, and obsolescence which is a relative deterioration. Recent history indicates[281], however, that there has been no heat rate improvement on a national basis for over a decade. Therefore, heat rate deterioration with age is only a function of material deterioration which is much less dramatic than the historic cycle improvements. Furthermore, older plants are traditionally smaller than newer plants. With the demand for electricity increasing exponentially, the capacity required for peaking and cycling in a system approaches the capacity of their older plants. Therefore, the older plants are usually derated to peaking and cycling service while the larger new units are base loaded. Temperature rise is not significantly affected by age (Figure B-V-4). While the trend has been slightly upward over the years, the increase has been slight (largely for thermodynamic reasons). Maximum outfall temperature has not changed materially over the years because the two determining factors (other than natural conditions) have changed in offsetting directions.

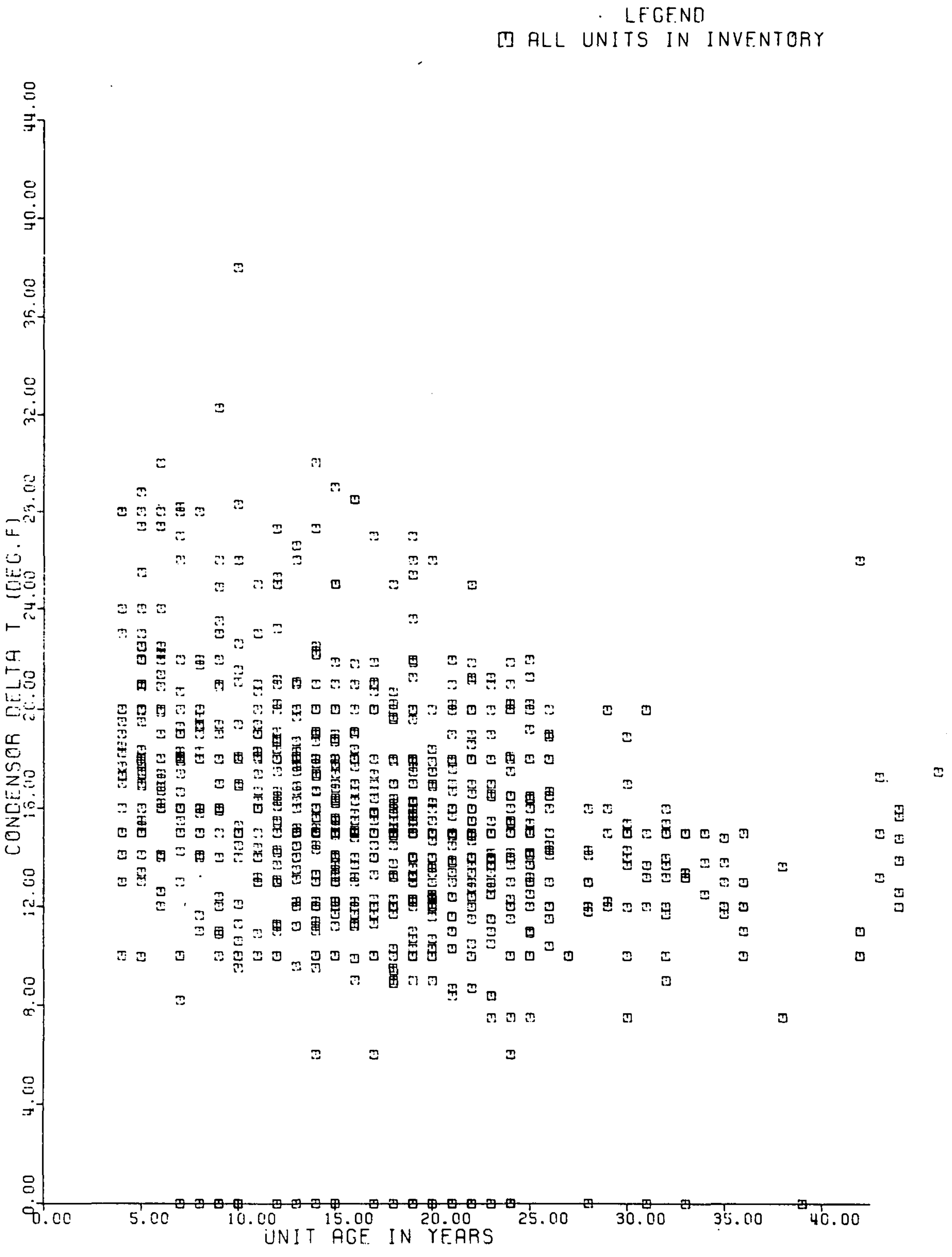
Unit capacity has a small effect on heat rate and virtually no effect on temperature rise. The effect on heat rate is due largely to engineering and capital cost considerations and to the fact that small plants are not usually base loaded.

Variation with Industry Grouping

Nuclear plants reject about 50% more heat to the cooling water per kwh than fossil plants. Fossil-fueled plants reject from 10% to 20% of the available fuel energy to the atmosphere through the stack. This energy leaves the plant in the form of water vapor (heat of vaporization) created by burning hydrogenous fuel and heated exhaust gases.

Nuclear plants reject virtually all their heat to the cooling water. If this were the only factor, nuclear plants of the same efficiency as fossil plants would reject from 18% to 43% more heat per kwh than fossil plants. However, nuclear plants of current design (PWR, BWR) cannot produce superheated steam for the generation cycle. For this reason, a well-designed nuclear plant can seldom be expected to exceed a thermal efficiency of 34% under even ideal conditions while well-designed, well-run fossil plants have achieved thermal efficiencies of up to 39% as an average for an entire year's operation (plant no. 3713)[281]. Thus, nuclear plants can be expected to reject more heat than fossil plants for thermodynamic reasons. The sum of these two effects yields cooling water heat rejection requirements in the range of 50% higher for nuclear plants than for fossil plants. The higher heat rejection requirements for nuclear plants are usually met by increasing the cooling water flow and slightly raising the temperature difference across the condenser. This method is practiced to avoid the additional thermodynamic inefficiencies associated with higher outfall temperatures.

Nuclear plants, then, closely approximate new fossil plants in temperature rise and maximum outfall temperature and are significantly higher in cooling water requirements. Fossil-fueled units can be divided into three categories, based on hours operated per year. The lowest group are operated less



DELTA T VS UNIT AGE

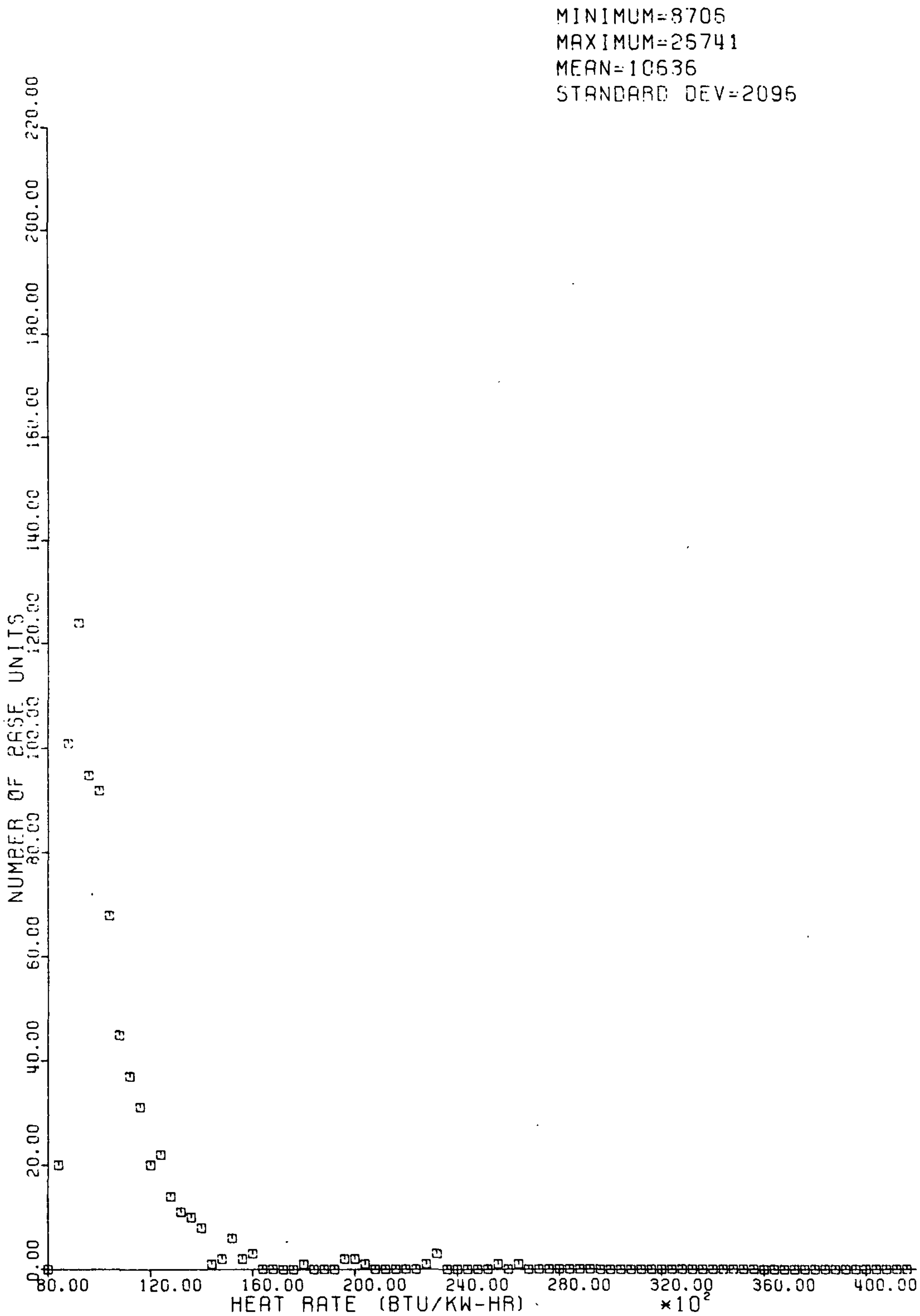
FIGURE B-V-4

than two thousand (2,000) hours per year. The intermediate group are operated more than two thousand (2,000) and less than six thousand (6,000) hours per year, while the highest groups are operated more than six thousand (6,000) hours per year.

The highest group heat rates average 11.25 million Joules per kwh (10,636 Btu/kwh, see Figure B-V-5) with a standard deviation of about 3.1 million Joules per kwh (2,100 Btu/kwh). Intermediate group heat rates average about 13.3 million Joules per kwh (12,494 Btu/kwh, see Figure B-V-6) with a standard deviation of about 3.1 million Joules per kwh (2,950 Btu/kwh), while the lowest group averages about 16.6 million Joules per kwh (15,793 Btu/kwh, see Figure B-V-7) with a standard deviation of 4.72 million Joules per kwh (4,480 Btu/kwh). The variation in the heat rate mean is over forty-seven percent, with heat rate varying inversely with utilization. The variation in cooling water heat rejection requirements is clearly higher than the variation in heat rate since the major portion of the additional heat must be rejected to the cooling water. This is only true when the plant is on-line. If a plant is on hot standby, the heat is rejected to the atmosphere through the stack. The impact of the increased heat rate is reduced sharply by two factors. The units with the higher heat rates are on-line less than the most utilized units and produce far less electric power. As a result, the total heat rejection per year is far less than for the most utilized units. Furthermore, a significant contribution to the high heat rates of the less utilized units is the practice of keeping these units on hot standby during periods when the probability of peaking demands is high. During these periods, these units produce no electricity and, therefore, have an infinite heat rate but reject little or no heat to the cooling water. Thus, the heat rate figures for the least utilized plants tend to be misleading (on the high side) as well as less important than those for the most utilized.

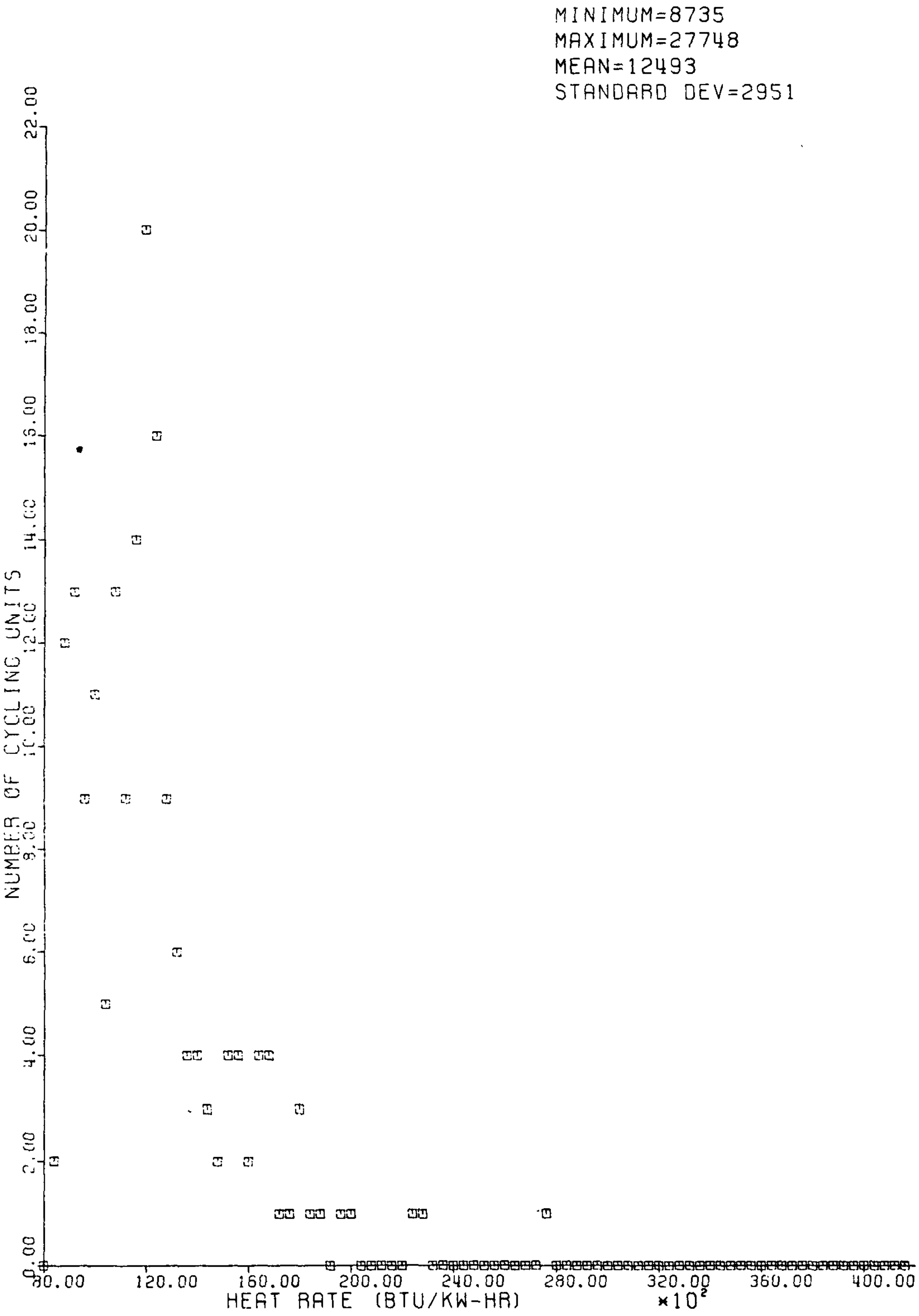
(It should again be noted that all statistics in this section are unweighted arithmetic means. Weighing averages by generation would produce lower heat rates, and, therefore, lower cooling water heat rejection requirements).

Condenser temperature rise does not vary with industry categorization (for fossil units). The mean for all three groups (based on hours operated per year) is about eight to nine degrees C (15-16 degrees F) with a standard deviation of a little under three degrees C (5 degrees F). (See Figures B-V-8, B-V-9, and B-V-10).



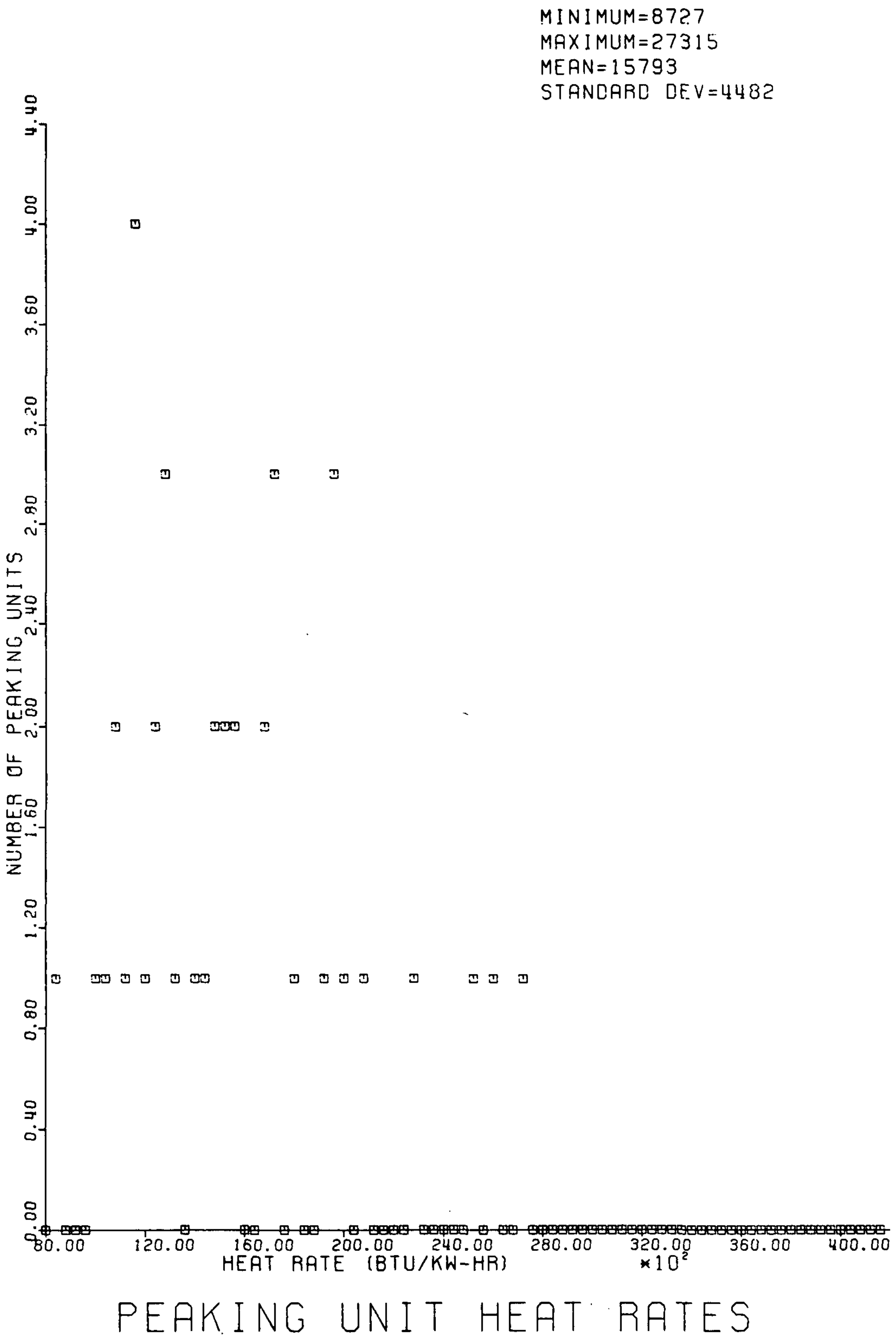
BASE UNIT HEAT RATES

FIGURE B-V-5



CYCLING UNIT HEAT RATES

FIGURE B-V-6



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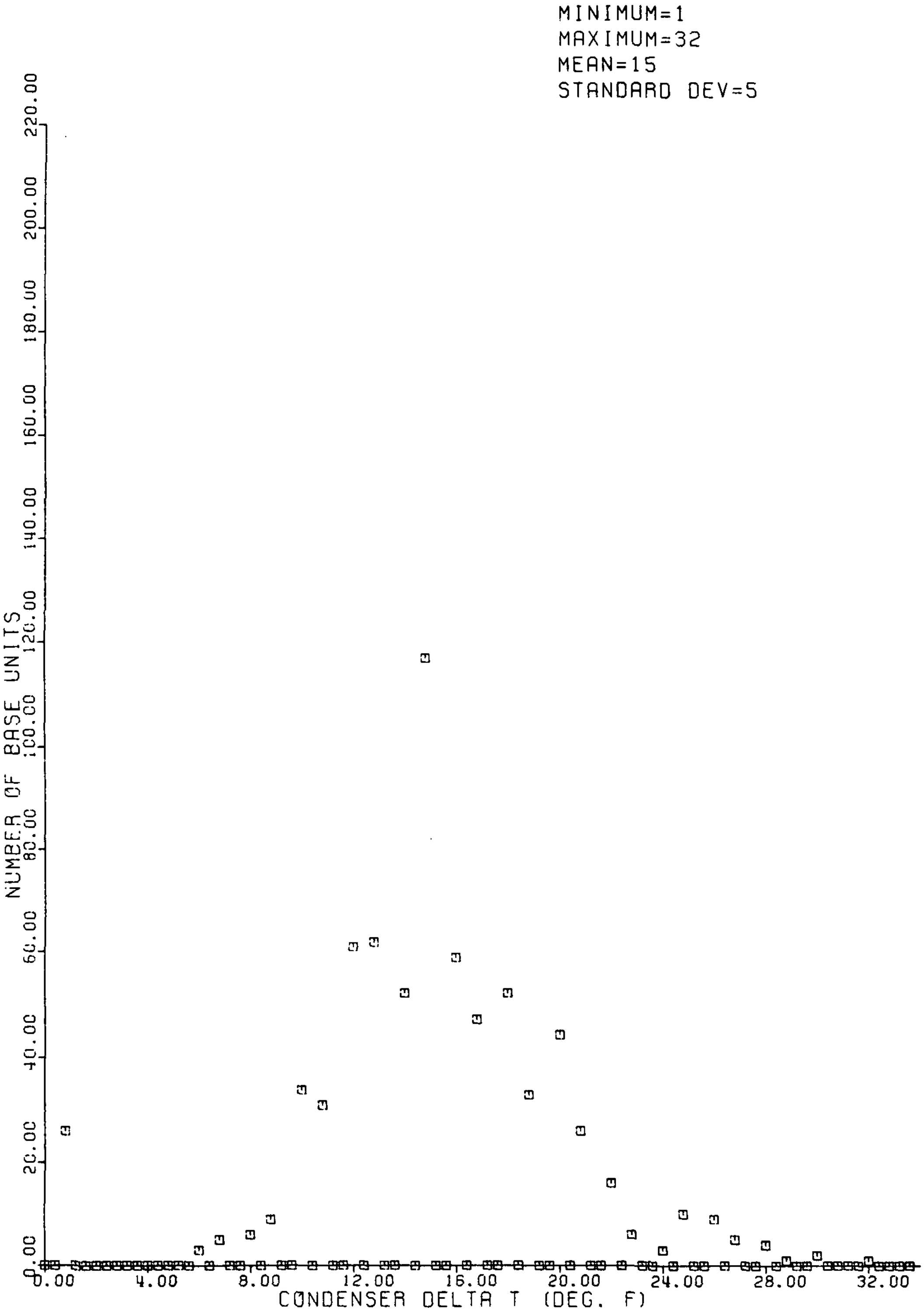
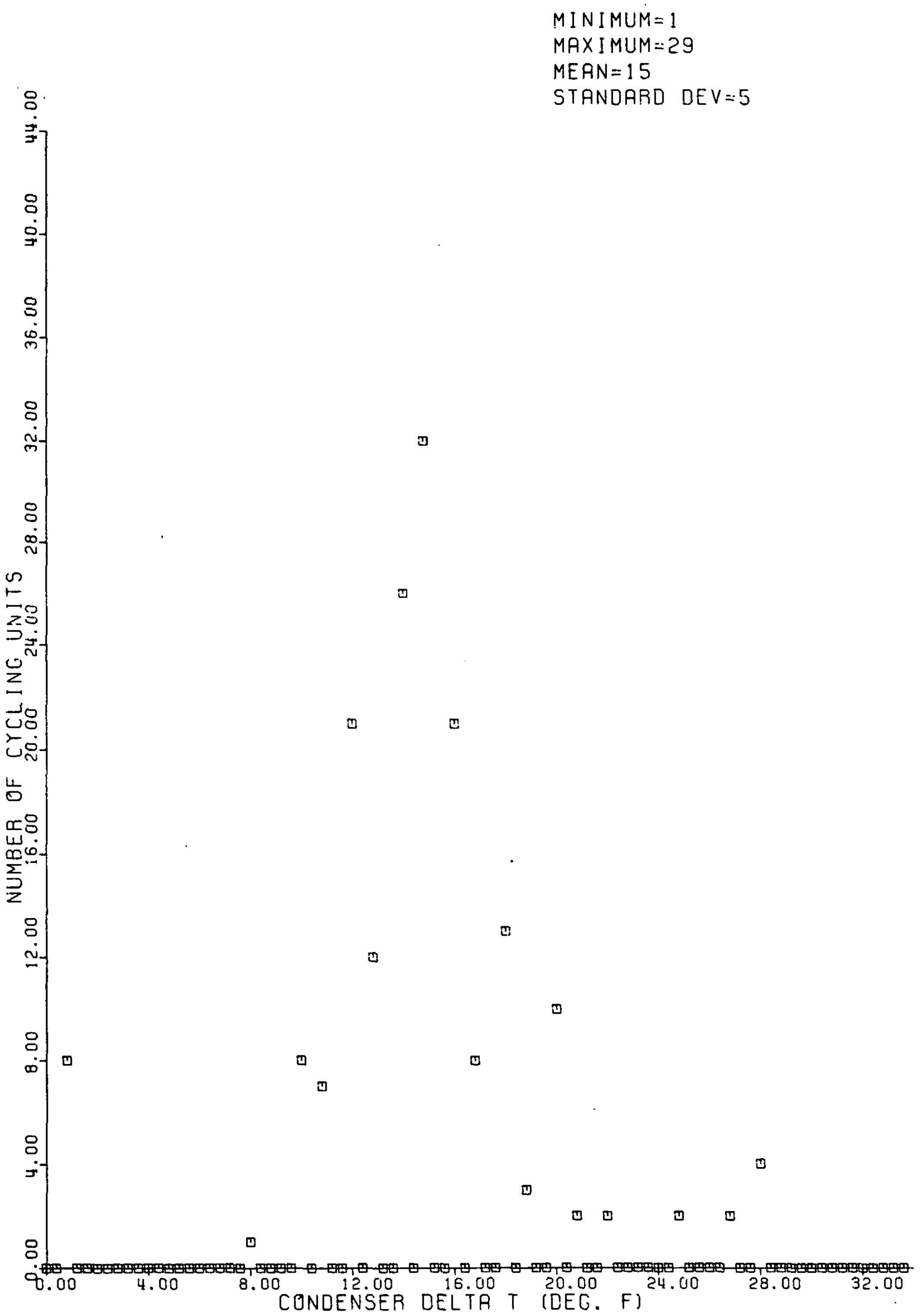
2.00
2.40
2.80
3.20
3.60
4.00
4.40
80.00
120.00
160.00
200.00
240.00
280.00
320.00
360.00
400.00
HEAT RATE (BTU/KW-HR)
$\times 10^2$
PEAKING UNIT HEAT RATES

FIGURE B-V-7



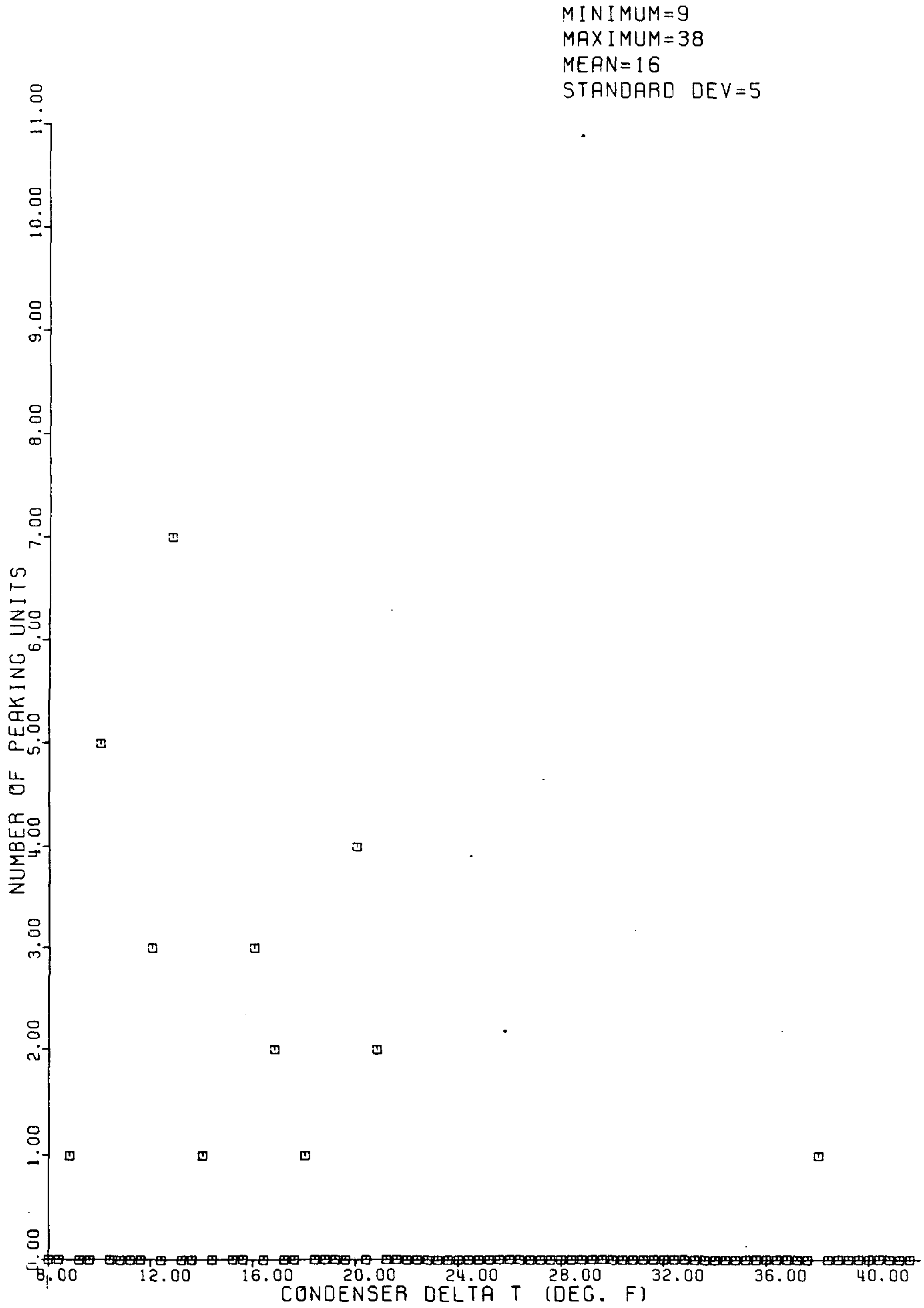
BASE UNIT CONDENSER DELTA T

FIGURE B-V-8



CYCLING UNIT CONDENSER DEL T

FIGURE B-V-9



PEAKING UNIT CONDENSER DEL T

FIGURE B-V-10

Maximum outfall temperature will not vary with industry grouping since it is the sum of ambient water temperature (which is unrelated to grouping) and temperature rise across the condenser (which does not vary with grouping).

In summary, the only waste stream characteristic which varies with industry grouping is the quantity of heat rejected to the cooling water. The other characteristics vary with locale, season, etc., and require site-by-site evaluation to draw any reasonable conclusion.

Finally, Table B-V-3 summarizes typical waste stream characteristic ranges for each grouping.

Effluent Heat Characteristics from Systems Other Than Main Condenser Cooling Water

Waste heat from house service water systems and other smaller sources can contribute about 1% of the total effluent heat discharged from a generating plant. For example, the thermal discharges of one nuclear plant (no. 4251) are shown in Table B-V-4. House service water systems can be either once-through (nonrecirculatory) or recirculating. Nuclear plants have emergency core cooling systems connected to the house service water system. Where closed house service water systems are used for nuclear plants, U.S. Atomic Energy Commission Safety Guide 27 requires (indirectly) that sufficient water be stored on-site (storage pond) to assure an ultimate heat sink for safety purposes.

Environmental Risks of Powerplants Heat Discharges

Reference 446 reports the results of analyses of the environmental risks associated with thermal discharges from powerplants by age, size, etc. based on a random sample of 180 plants with 455 units. The sample represents one-seventh of the U.S. generating capacity through 1978.

Table B-V-3

TYPICAL CHARACTERISTICS OF WASTE HEAT REJECTION

Grouping	Heat Rate, Joules/kwh x 10^{-7}	Heat Rejection to Water*, Joules/kwh x 10^{-7}	Temperature Rise, °C
Nuclear	1.02 - 1.16	0.72 - 0.80	10 - 16
Fossil (National Average) Reference 281	1.11	0.58	8.6
High Utilization	0.92 - 1.32	0.42 - 0.80	4.5-13
Intermediate Utilization	1.05 - 1.69	0.53 - 1.07	4.5-13
Low Utilization	1.05 - 2.1	0.53 - 1.43	4.5-11

* Note: Calculated by method discussed in this section for fossil-fueled plants and from Table B-V-2 for nuclear plants.

Table B-V-4

TOTAL PLANT THERMAL DISCHARGES
Plant No. 4251 (nuclear)

Cooling Water System	Flowrate, gpm	ΔT, °F	Heat, Btu/hr x 10^{-6}
Main Condenser	480,400	26	6,290
Primary Plant Components	5,800	22	66*
Secondary Plant Components	11,000	10	55
Centrifugal Water Chiller	3,000	9	13
Control Room Air Conditioner	200	10	1
Steam Generator Blowdown (Discharged 1 hr out of every 100 hr)	50 max	120	3 max

* Note: 175 x 10^6 Btu/hr during plant cooldown once a year.

PART B

THERMAL DISCHARGES

SECTION VI

SELECTION OF POLLUTANT PARAMETER

Rationale

The Act, Section 502(6), defines heat as a pollutant.

The purpose of this analysis is to suggest a functional parameter reflecting the level of effluent heat reductions achievable by the application of available control and treatment technology for steam electric powerplants. The determination of a suitable parameter for measuring the thermal component of the effluent is an essential part of the work in developing effluent limitation guidelines for thermal discharges.

The change that has occurred in the cooling water passing through the condenser is an increase in its internal energy. This term is also called "heat content". The change in internal energy or heat content is a product of the mass rate of water flow, its temperature increase, and its average specific heat.

Both the temperature increase of the cooling water and its discharge temperature do not include the quantity of water discharged at this temperature level, and thus do not reflect the total energy or heat discharged. A parameter based on temperature alone, therefore, would not be a reflection of the effluent heat in the discharge. To adequately evaluate the heat rejection to a receiving waterbody, a parameter reflecting total internal energy of the discharge is required.

The parameter that has been chosen in this report to represent the effluent thermal characteristics is the total increase in internal energy or heat content of the cooling water. This parameter directly reflects that change in the effluent which results in thermal effects.

The increase in internal energy or heat content of the cooling water is a function of the size of the powerplant. In order to compare different size plants, the increase in internal energy must be determined per kilowatt hour of plant output for each case. The increase in internal energy or heat content of the condenser cooling water is determined as follows:

$$U = \frac{m \times c \times T}{kw}$$

Where U = increase in internal energy of condenser cooling water

m = mass flow rate of cooling water

c = specific heat of cooling water

T = temperature increase of cooling water

kw = unit power output

With commonly used sets of units U would be expressed in J/kwh (Btu/kwh). Dimensionally, m is expressed kg/hr (lbs/hr) of cooling water, c = 4.186 J/kg/°C (1 Btu/lb/°F) and T is expressed in °C (°F)

For example, consider a powerplant with the following conditions:

Power output: kw = 225 x 10 kilowatts

Cooling water flowrate: m = 2.72 x 10 kg/hr (6.0 x 10 lbs/hr)

Temperature increase of cooling water: T = 11.1°C (20°F)

Specific heat of cooling water: C = 4.186 x 10 J/kg/°C (1 Btu/lb/°F)

The resultant internal energy increase is:

$$U = \frac{2.72 \times 10\ (4.186 \times 10\ )\ (11.1)}{225 \times 10} = 5626 \times 10 \text{ J/kwh}$$

or in English units:

$$U = \frac{6.10 \times 10\ \ (1)\ (20)}{225 \times 10} = 533 \text{ Btu/kwh}$$

This parameter provides a measure of the heat rejected to the receiving waterbody in a manner which can be readily monitored. The only quantities in the equation requiring measurement are the cooling water flow and temperature rise and power output of the unit. Each of these can be monitored directly without difficulty and utilized in a straightforward manner to compute the increase in internal energy or heat content.

Environmental Significance of Effluent Heat

The effects of effluent heat on the environment are generally correlated with water temperature.

Temperature is one of the most important and influential water quality characteristics. Temperature determines those species that may be present; it activates the hatching of young, regulates their activity, and stimulates or suppresses their growth and development; it attracts, and may kill when the water becomes too hot or becomes chilled too suddenly. Colder water generally suppresses development. Warmer water generally accelerates activity and may be a primary cause of aquatic plant nuisances when other environmental factors are suitable.

Temperature is a prime regulator of natural processes within the water environment. It governs physiological functions in organisms and, acting directly or indirectly in combination with other water quality constituents, it affects aquatic life with each change. These effects include chemical reaction rates, enzymatic functions, molecular movements, and molecular exchanges between membranes within and between the physiological systems and the organs of an animal.

Chemical reaction rates vary with temperature and generally increase as the temperature is increased. The solubility of gases in water varies with temperature. Dissolved oxygen is decreased by the decay or decomposition of dissolved organic substances and the decay rate increases as the temperature of the water increases reaching a maximum at about 30°C (86°F). The temperature of stream water, even during summer, is below the optimum for pollution-associated bacteria. Increasing the water temperature increases the bacterial multiplication rate when the environment is favorable and the food supply is abundant.

Reproduction cycles may be changed significantly by increased temperature because this function takes place under restricted temperature ranges. Spawning may not occur at all because temperatures are too high. Thus, a fish population may exist in a heated area only by continued immigration. Disregarding the decreased reproductive potential, water temperatures need not reach lethal levels to decimate a species. Temperatures that favor competitors, predators, parasites, and disease can destroy a species at levels far below those that are lethal.

Fish food organisms are altered severely when temperatures approach or exceed 90°F. Predominant algal species change, primary production is decreased, and bottom associated organisms may be depleted or altered drastically in numbers and distribution. Increased water temperatures may cause aquatic plant nuisances when other environmental factors are favorable.

Synergistic actions of pollutants are more severe at higher water temperatures. Given amounts of domestic sewage, refinery wastes, oils, tars, insecticides, detergents, and fertilizers more rapidly deplete oxygen in water at higher temperatures, and the respective toxicities are likewise increased.

When water temperatures increase, the predominant algal species may change from diatoms to green algae, and finally at high temperatures to blue-green algae, because of species temperature preferentials. Blue-green algae can cause serious odor problems. The number and distribution of benthic organisms decreases as water temperatures increase above 90°F, which is close to the tolerance limit for the population. This could seriously affect certain fish that depend on benthic organisms as a food source.

The cost of fish being attracted to heated water in winter months may be considerable, due to fish mortalities that may result when the fish return to the cooler water.

Rising temperatures stimulate the decomposition of sludge, formation of sludge gas, multiplication of saprophytic bacteria and fungi (particularly in the presence of organic wastes), and the consumption of oxygen by putrefactive processes, thus affecting the esthetic value of a water course.

In general, marine water temperatures do not change as rapidly or range as widely as those of freshwaters. Marine and estuarine fishes, therefore, are less tolerant of temperature variation. Although this limited tolerance is greater in estuarine than in open water marine species, temperature changes are more important to those fishes in estuaries and bays than to those in open marine areas, because of the nursery and replenishment functions of the estuary that can be adversely affected by extreme temperature changes.

PART B

THERMAL DISCHARGES

SECTION VII

CONTROL AND TREATMENT TECHNOLOGY

Introduction

This section contains a general discussion of the various methods for controlling thermal discharge from steam electric power stations. There are three methods available to reduce the gross amount of heat rejected to receiving waters from the steam electric power generation process. These methods are:

- process change
- waste heat utilization
- cooling water treatment

Various process changes can be made to the basic Rankine cycle to increase its thermal efficiency. These process changes include increasing boiler temperature and pressure rating, the addition of reheat and regenerative cycles and reducing turbine exhaust pressure. In addition, the Rankine cycle can be replaced with other forms of generation which are inherently non-polluting. Several of these new forms of generation are already available, such as the gas turbine Brayton cycle and the combined cycle plant. Looking to the future, transfer of gas turbine technology from the aerospace industry offers the promise of gross plant thermal efficiencies approaching 50% in the latter part of the decade. Since the gas turbine is air cooled, its increased use can significantly reduce heat rejection to receiving waters.

The replacement of the conventional Rankine steam plant with other forms of power generation is also receiving increased attention. It is anticipated that conservation of available energy resources will require larger expenditures in coal research and in the development of new power generation technologies which do not require fluid fossil fuel. These new generation technologies include solar generation, fuel cells, MHD and geothermal power. In the nuclear power field, the production of a demonstrator breeder reactor by the end of the decade will lead to higher thermal efficiencies in nuclear power generation.

The utilization of portions of heat contained in the discharge of condenser cooling water can reduce the amount of heat rejected from steam electric powerplants. There are two different ways in which power station waste heat can be beneficially employed by others. This first is to use the low grade heat contained in the condenser cooling water itself. Several small-scale projects for utilizing low-grade heat (mostly for agriculture and aquaculture purposes) will be described. Other uses for partially expanded steam (extraction steam utilization) for industrial process steam, space heating and cooling, and water desalting have been practiced at several locations in conjunction with electric power generation. The use of extraction steam methods generally involves a degradation of the power cycle since the steam at the extraction point has significant enthalpy remaining. Because of this loss of cycle efficiency, extraction steam utilization tends to raise the heat discharged as measured in Joules/kwh. It is necessary in evaluating this type of alternate use of steam to combine both the powerplant and the alternate use to determine the benefits derived.

The major weakness of most programs of low-grade heat utilization and single-purpose extraction steam utilization is that many of the alternate uses of the available heat are seasonal. This means that the additional costs associated with providing the steam distribution systems must be written off over relatively few hours during the year. It also means that the full amount of heat must be discharged to the waterway during those periods when the secondary heat consumers are not operating. This weakness largely defeats the purpose of employing low-grade heat utilization systems. The total energy concept seeks to overcome this shortcoming by aggregating all uses of heat in a region to fully utilize available energy on a year-round basis. Most total energy systems in this country are small, consisting of individual shopping centers, educational complexes and commercial developments. Larger total energy systems exist in Europe. It is felt that the rapidly increasing cost of energy brought about by greater worldwide competition for the earth's remaining fossil-fuel resources will make the total energy concept more attractive in the future. Several different waste heat utilization projects will be described.

A number of different technologies have been applied to condenser cooling water discharges to reduce heat rejected to the waterways. Three basic treatment options are available; open cooling systems, closed cooling systems, and combinations of the two. Open cooling systems discharge the full condenser flow following supplemental cooling. Closed systems recycle the bulk of the circulating water flow back to the condenser following supplemental cooling and discharge a small fraction as blowdown to control salinity buildup in the system.

Open cooling systems employing evaporative cooling have the basic disadvantage of not being able to maintain a desired level of treatment year-round due to seasonal variations in wet bulb temperature. Open cooling systems have a distinct advantage over closed systems in that they do not affect the turbine backpressure. A closed cooling system can produce a low-level heat discharge year-round at the expense of increased turbine backpressures. Increasing turbine backpressure entails increased station cost above the cost associated with the cooling system. These additional costs are incurred to buy replacement power for those periods when the station (because of high backpressures) cannot produce its rated capacity (capacity penalty) and also to pay for increased fuel cost for less efficient turbine performance (energy penalty). Both open systems and closed systems require additional power to operate pumps, fans, etc., which affects station capacity and fuel cost to some degree. Incremental capacity and fuel costs are higher for backfitting existing units than for new units.

Most existing treatment of condenser cooling water has been designed to operate in a recycle mode. These systems have generally been installed where sufficient water for once-through cooling was unavailable. Some closed systems are designed to allow open system operation for a portion of the year. All of the available cooling water treatment technologies will be described in this section.

Process Change

Background

In order to properly understand both the problems and possible solutions regarding thermal discharges from powerplants, it is necessary to review a few essential thermodynamic principles. Only those principles that directly relate to the situation being investigated will be discussed. They will be presented in simplified terms, allowing a small relaxation of rigorous scientific exactitude.

The discussion is presented in three steps. First presented are principles, and then shown how they affect the steam electric powerplant cycle. Next, historic developments are reviewed, relating them to the principles. This is important to understanding some approaches to improving plants in regard to thermal effects. Finally, we have related principles as guides to possible new types of power generating systems with improved thermal effects characteristics.

Thermodynamics is the study of the conversion of energy from one form to another, particularly the forms of energy called "heat" and "work". The purpose of a steam electric powerplant is to convert heat into work or power, which is the rate of work. Thus, steam electric powerplants are directly concerned with thermodynamics. Important questions to pose about this process of getting work from heat are:

1. How can we increase the amount of work obtainable from a given amount of heat?
2. Is there a limit to how much work obtainable from a given amount of heat?
3. What happens to the heat that is not converted into work?

Thermodynamics is based largely on two laws. These are called the "First Law" and "Second Law". Before stating these laws, it is necessary to include a few definitions of words or phrases used in the statements of these laws, or in explaining them.

Heat engine (powerplant) - a device or plant used to convert heat into work.

Energy - the ability to do work. Heat and work are both forms of energy. Work may appear as mechanical energy (such as the rotation of a wheel) or electrical energy.

Cycle - the processes or changes which the working fluid of heat engine (powerplant) goes through.

Efficiency - the proportion of energy input (heat) to a powerplant which is converted to energy output (work).

Reservoir - an energy source or an energy receiver.

There are a number of ways of stating the laws of thermodynamics. We have chosen a special phrasing that seems most applicable to this study. It should be remembered that this is a restricted non-rigorous statement.

First Law - the total energy supplied to a powerplant must be removed from the plant.

This statement is akin to the conservation of energy interpretation of the First Law, i.e., there must be a budget or accounting of the energy, and this budget must balance.

Figure B-VII-1 shows a simplified example of the energy flow for a power producing engine or plant.

The powerplant receives energy in the form of heat from combustion of fossil fuels, or from nuclear reaction. Some of this energy is converted to a useful output in the form of work (electricity). There is also heat energy output from the plant. This is mainly the energy associated with thermal discharge to receiving waters.

The First Law, which requires an energy balance, thus can be stated in equational form for this example as:

> Energy In (Heat) = Energy Out (Work) + Energy Out (Heat)
> or rearranging Energy Out (Heat) = Energy In (Heat) -
> Energy Out (Work)

The importance of this for thermal discharges is that once the proportion of Heat Energy In that is converted to Work Energy Out is determined, the remainder is a source of thermal discharge. For example, in Figure B-VII-2 relative values of energy are indicated for a hypothetical powerplant. For this plant, for every 100 units of energy input, 40 units are converted to useful work. The First Law reveals that inexorably there are 60 units of energy that must be rejected to the surroundings. (The relative values in this example are close to those typical of modern steam electric powerplants).

Note however, that the First Law does not require that any heat be rejected from the powerplant. It only says that we cannot produce more energy in the form of work than the quantity of energy (in the form of heat) supplied. At this point, the following might be asked:

> "Does the energy rejected have to be in the form of heat?" "Can we build a plant with a better efficiency than in the example cited, which seems pretty inefficient (40%)?" "Is there any limit on efficiency, other than economic considerations? This is, can we reduce the heat rejected to the environment, without limit?"

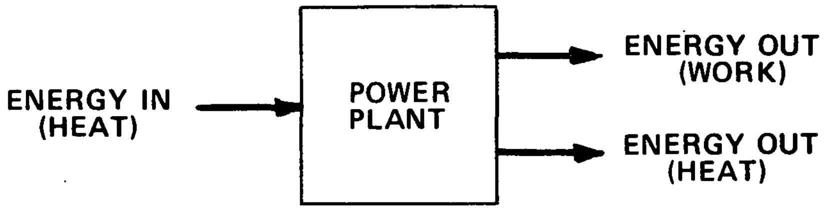


FIGURE B-VII-1 ENERGY FLOW FOR A POWER PLANT

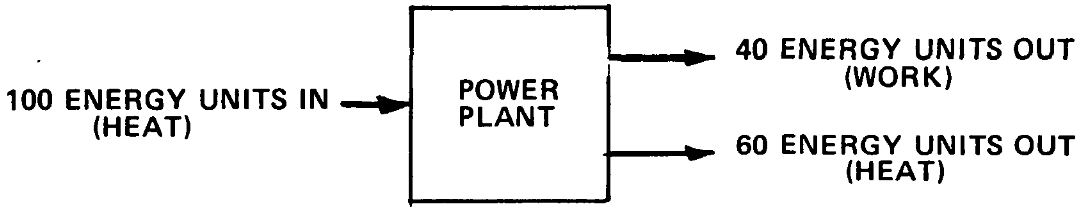


FIGURE B-VII-2 ENERGY BALANCE FOR A POWER PLANT (FIRST LAW)

Such questions have important implications. They lead to a statement of the Second Law of Thermodynamics:

> "It is impossible for a powerplant to receive heat energy from a source and to produce the same amount of energy as work."

It might be noted at this point that the Second Law of Thermodynamics cannot be proven from other principles. It is a conclusion reached by experience: observation and experimentation. We can picture a powerplant that would violate the Second Law as stated in Figure B-VII-3. Note that it does not violate the First Law. In order to bring this powerplant into conformity with the Second Law, we try to rearrange its operation as shown in Figure B-VII-4. We are not producing the same amount of energy as work, as was supplied in the form of heat. But now we are violating the First Law, as there is an energy unbalance.

In order to make this plant conform to both laws, we must rearrange its operation as shown in Figure B-VII-5.

The remaining 60 energy units in the form of heat must be rejected to the receiver, which is the environment.

Based on our senses and experience, we are usually psychologically comfortable with the First Law. It expresses a principle that a budget must balance. Yet the Second Law may seem irrational. There seems to be nothing unnatural in having a powerplant receive heat energy and, as a result, produce some power with no other results or effects occurring. Nevertheless, evidence indicates that such a powerplant cannot be built. Some heat must be rejected. But how much? Could we build a powerplant that is 99% efficient, if we considered it financially feasible, thus rejecting a negligible quantity of heat to the environment?

There is an upper limit on the efficiency of any powerplant. This limit is that provided by a powerplant that operates on a completely reversible cycle. In this type of cycle, the plant receives heat only at a constant temperature and rejects heat only at a constant temperature. In addition, there are no losses such as friction in any of the processes taking place. The efficiency of such a powerplant depends only on the temperature at which the plant receives heat from the source, and the temperature at which it rejects heat to the surroundings.

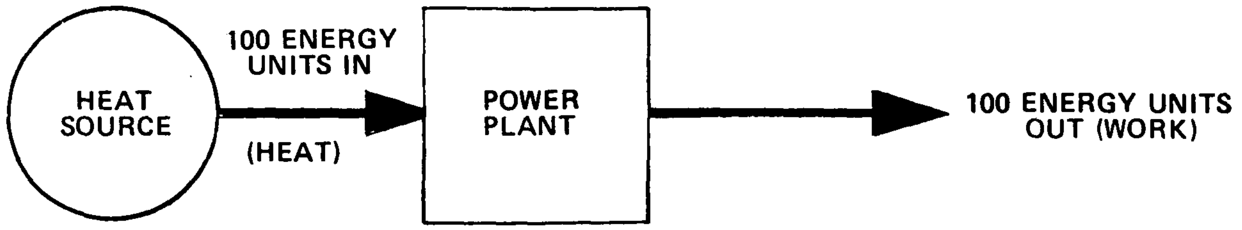


FIGURE B-VII-3 POWER PLANT VIOLATING SECOND LAW

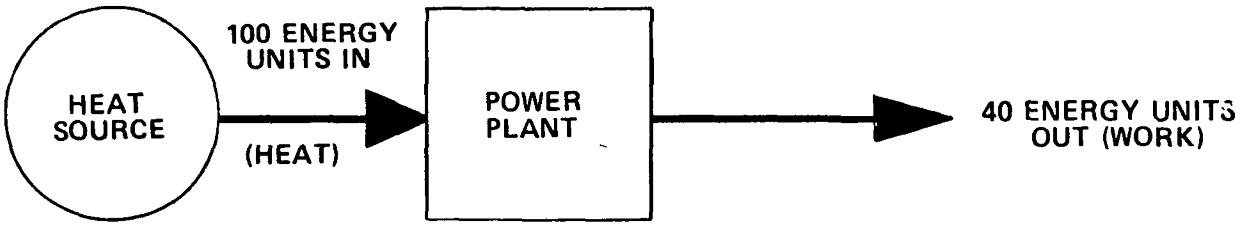


FIGURE B-VII-4 POWER PLANT VIOLATING FIRST LAW

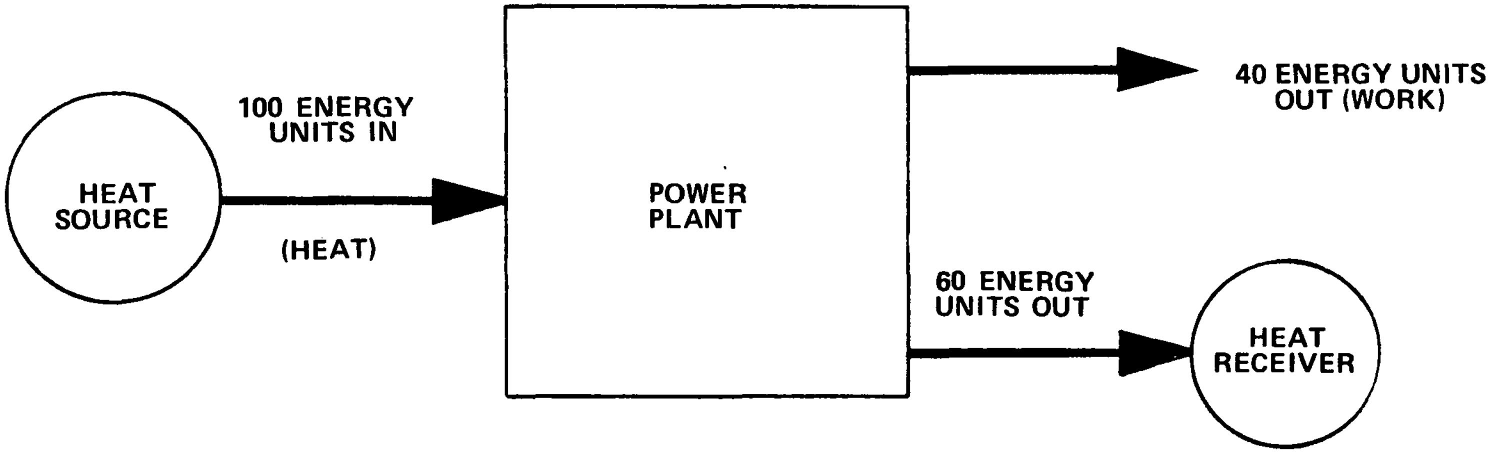


FIGURE B-VII-5 POWER PLANT CONFORMING TO FIRST AND SECOND LAW

The efficiency of this type of plant can be determined from the following equation:

$$Erc = 100\left(1-\frac{T2}{T1}\right) \qquad (1)$$

where Erc = efficiency of reversible cycle powerplant

T1 = temperature at which plant receives heat from heat source, expressed in absolute units

T2 = temperature at which plant rejects heat to surroundings expressed in absolute units

This equation can be derived from the Second Law of Thermodynamics, in a somewhat lengthy procedure. There are a number of these completely reversible cycles that have been conceived of. The best known is called the Carnot cycle. For this reason, the above efficiency is often called the Carnot Efficiency, although any cycle that meets the specified conditions will have the same efficiency.

It will be instructive to determine what the efficiency of a completely reversible cycle would be for temperatures representative of modern steam electric powerplants. The maximum temperature at which a plant receives heat is about 600°C (1,000°F). This is a limit resulting from the decreasing strength of metals at elevated temperatures. The minimum temperature at which a plant rejects heat is about 32°C (90°F). This is a limit resulting from the available temperature of normal surroundings, unless a plant could reject heat to outer space at absolute zero, -273°C (-460°F).

Converting these temperatures to their absolute values, (degrees Rankine), and calculating the efficiency:

$$T1 = 1000 + 460 = 1460°R$$

$$T2 = 90 + 460 = 550°R$$

$$Erc = 100\left(1-\frac{550}{1460}\right) = 62\%$$

This is the highest efficiency that can be reached by any powerplant operating within these temperature limits. The efficiency of the most modern powerplants incorporating the best technology features, operating within these temperature limits, reaches 40%. These modern powerplants achieve a quite high efficiency, relative to the maximum. If one does not consider the Second Law limitations, 40% seems a low figure, and we might conclude that great increases in efficiency could be made with reasonable research investment. But in reality, the "perfect" powerplant under these conditions is itself only 62% efficient. Thus, an actual modern powerplant has an efficiency relative to the theoretical possible of:

$$\text{Relative Efficiency} = \frac{40}{64} \times 100 = 65\%$$

Considering additionally, the minimum practical losses in each of the components in a powerplant, even the relative efficiency of 65% is low as an indicator of the likelihood of further improvements in the existing steam electric powerplant cycle. In any case, even with the best theoretical cycle, the same basic problem would exist of discharging large amounts of waste heat to the surroundings, since only about a 33% reduction in present thermal discharges would be accomplished.

Referring to Equation (1), note that the efficiency of the completely reversible cycle is increased by raising T1 or lowering T2, and that 100% efficiency can be achieved only with an absolute zero temperature T2, or approached with an infinite temperature T1.

History of the Steam Electric Power Plant Cycle

In this section, we will outline the chronological development of the thermodynamic cycle of the steam electric powerplant. The purpose of this approach is to indicate what methods have been developed to improve cycle efficiency, and indirectly reduce the heat discharged to the environment. This will aid in understanding problems and possible directions for future cycle improvements.

The discussion should begin with a description of a completely reversible cycle, as it is the best theoretically achievable. In this way, each actual powerplant development may be compared to the paragon.

The Carnot cycle is chosen as the completely reversible cycle to describe. Figure B-VII-6 shows the basic components of the Carnot steam powerplant cycle: boiler, turbine, condenser and compressor. The components are connected by piping as shown, with the direction of flow of the fluid between them as indicated.

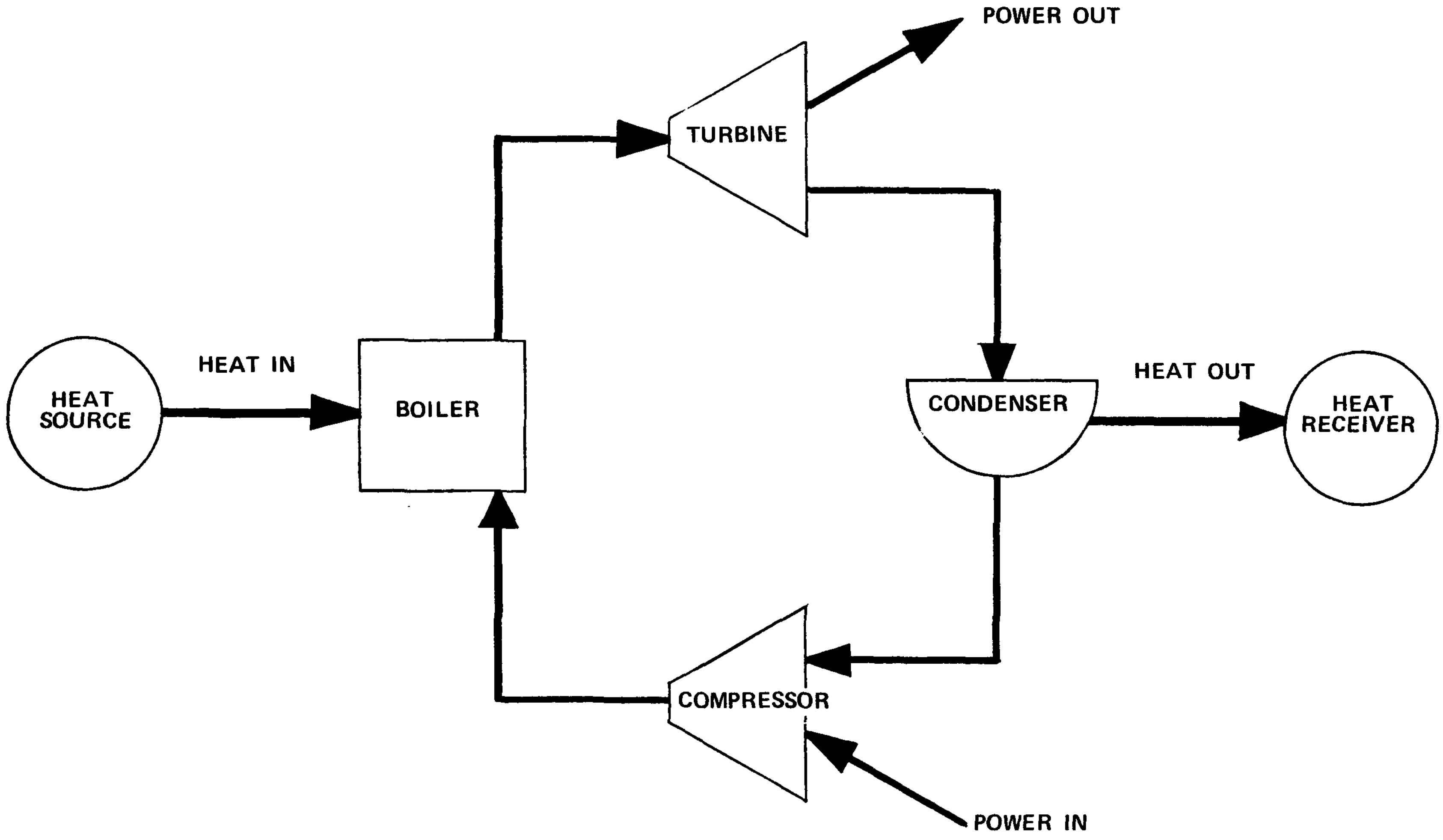


FIGURE B-VII-6 CARNOT CYCLE STEAM POWER PLANT

The heat source may be combustion of fossil fuel or nuclear reaction (or recently geothermal heat). Heat is transferred from the source to water in the boiler. The water enters the boiler in a saturated liquid condition. This means that it is at a temperature where it will begin to boil when heated. It does not need to be heated up to boiling temperature. The water is completely evaporated, and it leaves as saturated steam. This means that it has been completely converted to vapor, but its temperature has not increased. (Further heating of the vapor to a higher temperature produces superheated steam).

The steam then flows to a steam turbine, where its energy is used to rotate a shaft and generate power. In so doing, the steam temperature and pressure drop considerably in the turbine. Steam leaving the turbine flows to the condenser, where heat is removed from it.

The condenser removes enough heat to partially condense the steam entering. Thus a mixture of liquid and vapor leaves the condenser. The temperature of the condensing steam does not change during the process. This mixture is then compressed in a compressor. This compression process raises the temperature and pressure of the fluid, and also causes the condensation of the remaining vapor. The result is that the fluid leaves the compressor at the pre-determined conditions set for the boiler, as a saturated liquid. Note that power is required to operate the compressor.

As heat is added in the boiler at a constant temperature and removed in the condenser at a constant temperature, and assuming no losses in any equipment, the cycle will be a completely reversible one, with the maximum efficiency possible for the temperatures specified.

With this paragon continually in mind as a reference standard, let us now turn to the historical development of the actual cycles used in the steam electric powerplant. We have observed that the cycle modifications and developments improved efficiency, usually however, at the expense of increased plant complexity. We also note that the developments brought the actual cycle closer to some of the features of the Carnot cycle, which being the best possible, is not a surprising development. Yet the Carnot cycle itself has great practical deficiencies.

It is worth noting that the development of the cycle was largely accomplished by inventive-minded engineers, and to a great extent at a time before thermodynamics was a fully understood or applied science.

Rankine Cycle

Named after the engineer W. J. M. Rankine (1820-1872), Professor at the University of Glasgow, the components and flow for this cycle are shown in Figure B-VII-7.

The cycle has four basic components: boiler, turbine, condenser and pump. A heat source furnishes heat to the boiler. Water entering the boiler is first heated up to its saturation temperature and then evaporated completely. The steam flows

to the turbine where its energy is used to rotate a shaft and generate power. The steam leaves the turbine at a lower temperature and pressure, and flows to the condenser. Here the steam is completely condensed to liquid water by removing heat. A pump delivers the feedwater to the boiler at the boiler pressure. Some of the heat is added in the boiler to the water, which is at a temperature lower than it would be in the boiler in a Carnot cycle at the same maximum temperature. Thus the efficiency of the Rankine cycle will be lower than that of the Carnot cycle.

Rankine Cycle with Superheat

Even at very high pressures, the boiling temperature of water is considerably lower than can be achieved in the boiler, with present technology. Recalling the fact that the higher the temperature at which heat is added to the plant, the greater the efficiency, this means that with the Rankine cycle, efficiency is unnecessarily restricted.

A relatively simple means of improving this situation is to superheat the steam. A schematic flow diagram of the Rankine cycle with superheat is shown in Figure B-VII-8. After the water has been completely evaporated, the steam is superheated to a higher temperature, within metallurgical limits. As the average temperature at which heat is supplied to the plant is higher than with the simple Rankine cycle, a higher efficiency will result.

Regenerative Cycle

With the Rankine cycle, water entering the boiler is at a relatively low temperature, i.e. the temperature at which it is condensed in the condenser. As with the Carnot cycle, the lower the condensing temperature, the greater the efficiency. However, with the Rankine cycle, having this cool water entering the boiler means that a good part of the heat is added to the working fluid at an average temperature considerably below the maximum.

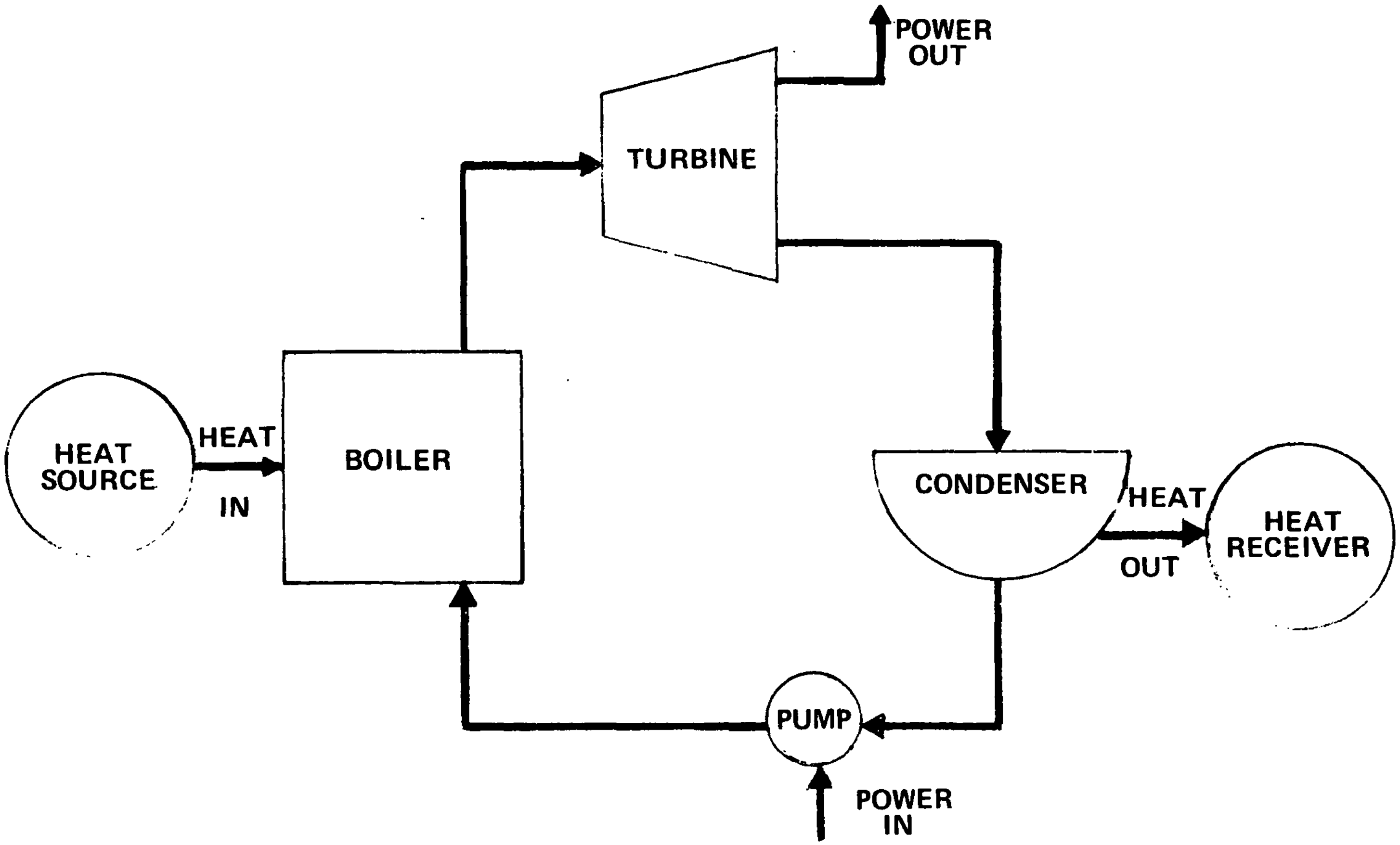


FIGURE B-VII-7 RANKINE CYCLE POWER PLANT

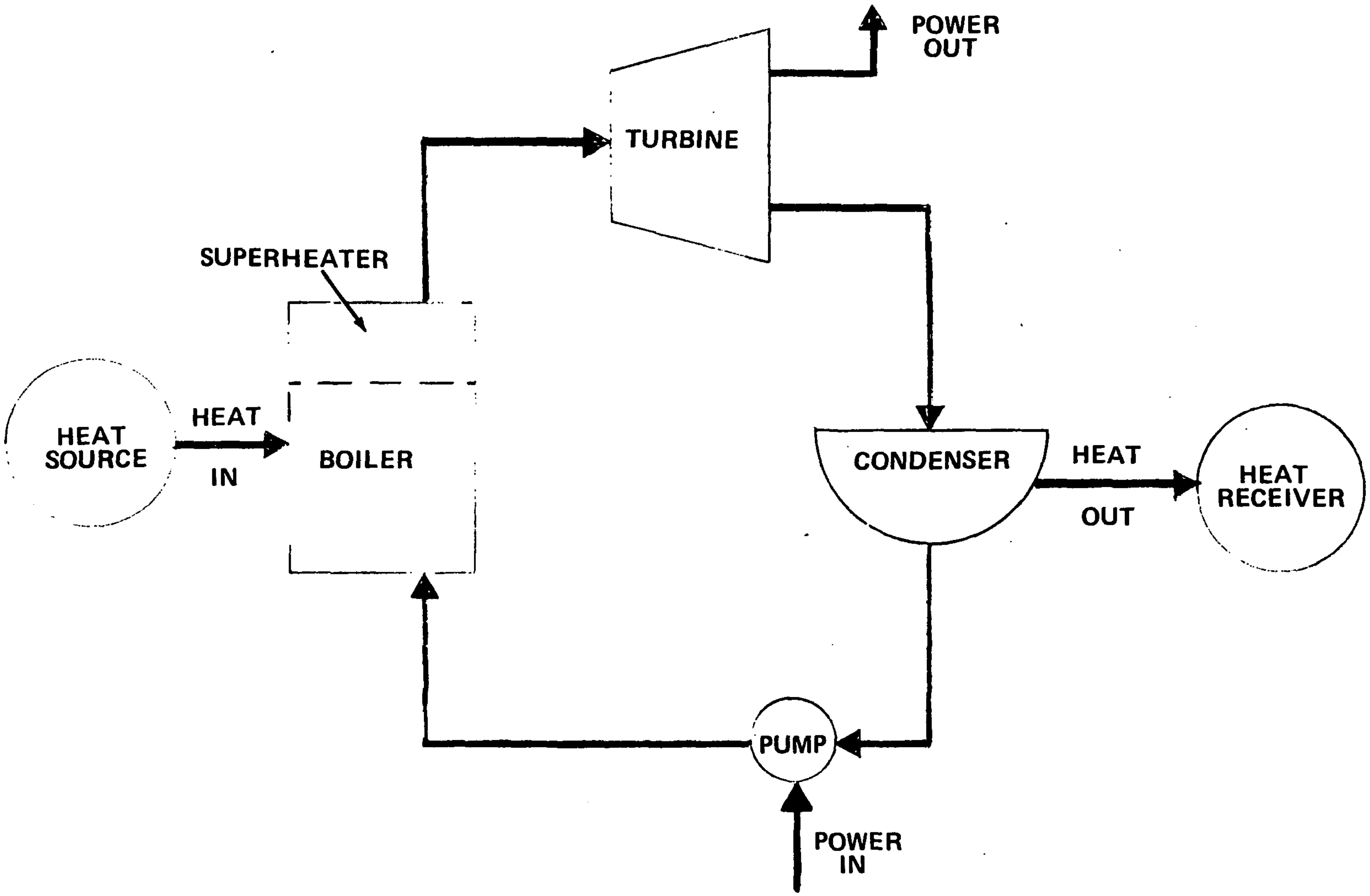


FIGURE B-VII-8 RANKINE CYCLE WITH SUPERHEAT POWER PLANT

If the average temperature at which heat is added could be increased, the cycle efficiency would improve. This is the basis for the regenerative cycle. A schematic flow diagram with components for one version of the regenerative cycle shown in Figure B-VII-9.

In this cycle, the boiler feed water is preheated in a heater before entering the boiler, by means of steam at an intermediate temperature and pressure bled from the steam turbine. The water entering the boiler is therefore at a higher temperature than it would be with the Rankine cycle. The heat added from the external source will now be added in the boiler at a higher average temperature, and the cycle efficiency will be higher.

To increase the efficiency still further, a few heaters in series can be used, with steam bled from the turbine at progressively different conditions. Of course, the complexity and cost of the plant increases with more heaters.

As the number of feedwater heating stages increases, the regenerative cycle more closely approaches the Carnot cycle, because less of the heat is added externally at lower than maximum temperatures (more is being added internally - hence the word regenerative). The question naturally arises as to why the Carnot cycle itself is not used, as it has a greater efficiency, and would avoid the complexity and expense of the feedwater heating stages.

In actual conditions, the Carnot cycle applied to real equipment would have a poor efficiency. The turbines, pumps and compressors have losses due to mechanical friction, fluid turbulence and similar phenomenae. Thus the pump and compressor will require more power to operate than under ideal conditions. It is the nature of the Carnot cycle that the compressor is a very large power consuming device. In a real plant, the actual power to operate this compressor would reduce the actual plant efficiency considerably. The Rankine cycle does not suffer from this shortcoming, as the pump requires relatively only a small amount of power.

Reheat Cycle

As the steam expands in the turbine, in addition to its temperature and pressure dropping, it begins to condense. The result is that in the latter stages of the turbine liquid water droplets form. Only a small amount of moisture can be tolerated, due to possible erosion of the turbine blades and reduction of turbine efficiency. Depending on

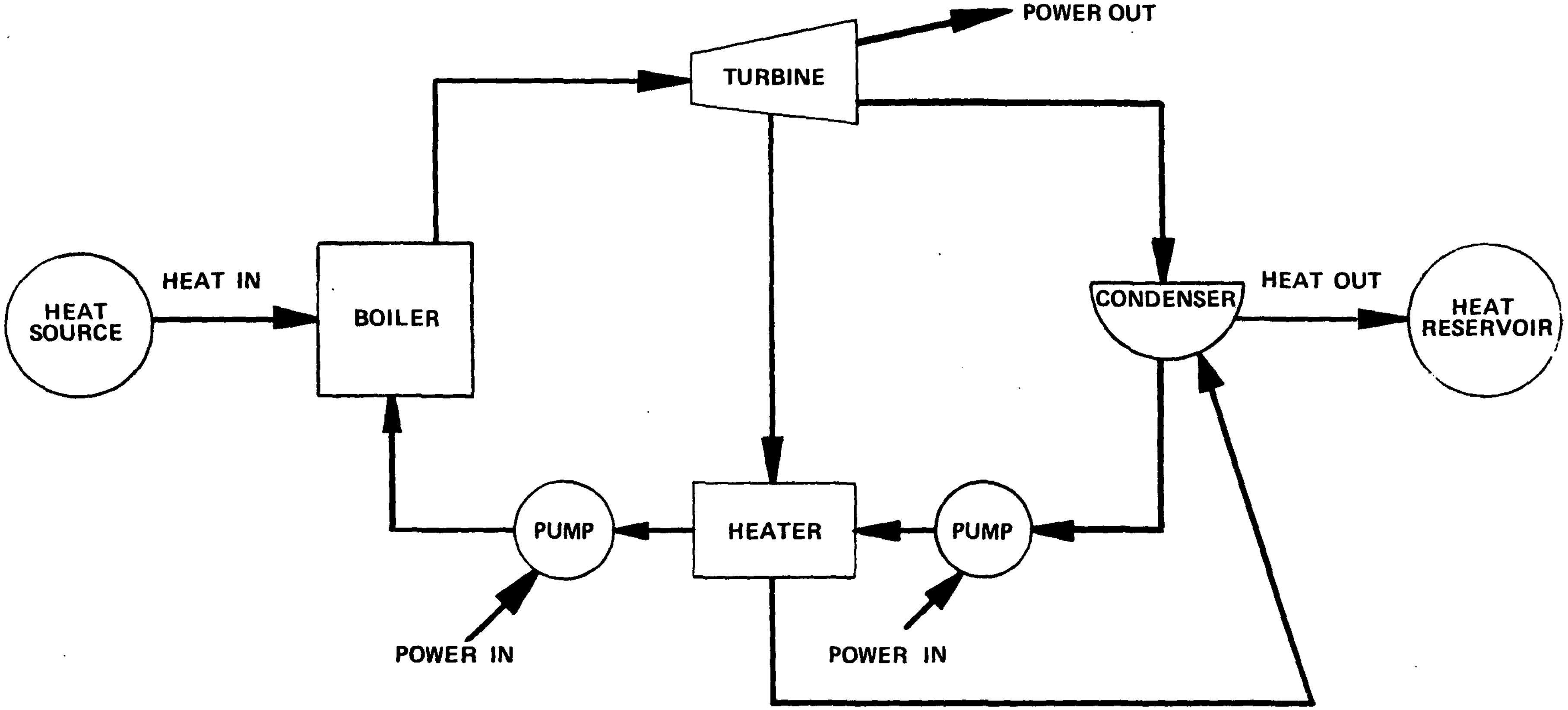


FIGURE B-VII-9 REGENERATIVE CYCLE POWER PLANT the inlet temperature and pressure, if the designer attempts to use the minimum condensing temperature available, the moisture content in the turbine might be excessive. In that case, he would have to design the Rankine or regenerative cycle with a higher condensing temperature and suffer a loss of efficiency.

A method of overcoming this difficulty is with the reheat cycle. Figure B-VII-10 is a flow diagram of a typical reheat cycle.

Steam leaving the superheater enters a high pressure turbine. The steam does not expand in this turbine to a temperature low enough to create excess moisture. The steam leaving the turbine is reheated at the lower pressure back to a high temperature. It then flows to a low pressure turbine where it can be expanded down to the minimum condensing temperature without excess moisture being created in the turbine. The reheat cycle can be combined with the regenerative cycle also, in a similar manner.

Historical Process Changes

Changes in existing processes or their conditions may be considered as a possible way to improve plant heat rate and thus reduce heat rejection. It is worthwhile to see how the plant heat rate has already been improved by such changes up to the present time, and then to view the progress for further improvements.

By the 1920's typical plants used steam pressures and temperatures reaching about 1,900 kN/sq m (275 psi) and 293°C (560°F). The improved equipment and materials that became available in the decade enabled pressures and temperatures to be increased to the neighborhood of 3,792 kN/sq m (550 psi) and 343°C (650°F), resulting in increased efficiency. Expansion in the turbine from these conditions, however, resulted in excessive moisture in the turbine, and as a result these plants adopted the reheat cycle.

By the 1930's further material improvements resulted in the availability of steam pressures and temperatures of about 6205 kN/sq m (900 psi) and 482°C (900°F). Under these conditions, expansion in the turbine occurs down to minimum condensing pressure without excessive moisture, and as a result plants were typically designed without reheat.

Further material improvements since the 1930's resulted in higher available steam pressures. A pressure of 17,200 kN/sq m (2,500 psi) and temperature of 538°C (1,000°F) might

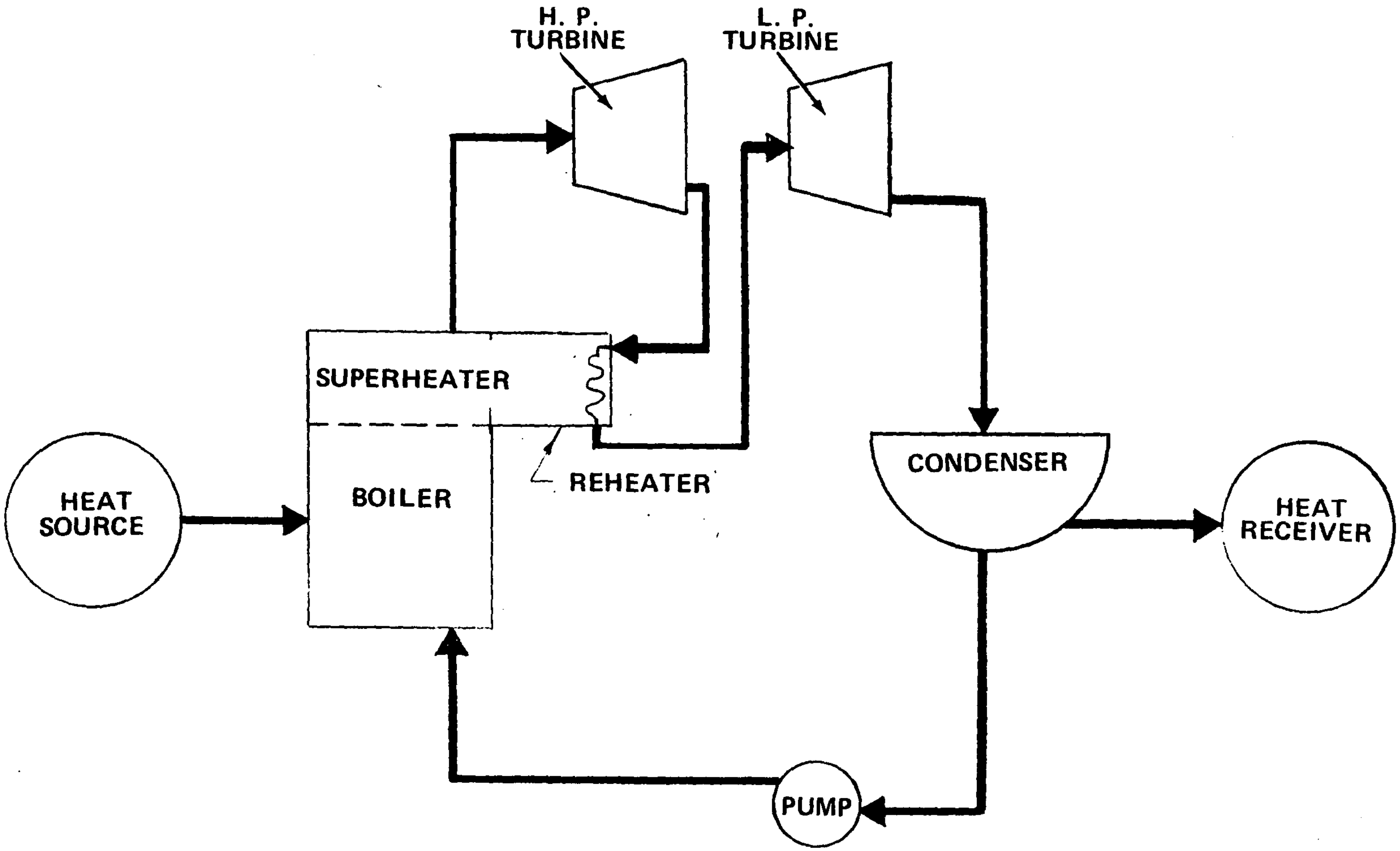


FIGURE B-VII-10 REHEAT CYCLE POWER PLANT be typical today. This increase in pressure with correspondingly little increase in temperature would result in a condition of excessive moisture if full expansion were taken in the turbine in one pass. Because of this, reheat has been adopted again in recent decades. In addition, higher fuel costs justify the increase in efficiency gained from reheat. Generally only one stage (single) reheat is economical. For plants that are designed to operate at supercritical pressures 2,400 kN/sq m (3,500 psi), however, double reheat may be justifiable. Triple reheat has not been found economically feasible under any conditions. Along with these developments, adoption of the regenerative cycle had become standard due to its increased efficiency over the Rankine cycle. The efficiency increases with the number (stages) of feedwater heaters used, but of course the plant initial cost increases correspondingly. For large plants, present costs justify 7 or 8 stages of heating.

Process Changes for Existing Plants

A summary of possible individual changes in existing plants is shown in Table B-VII-1, Efficiency Improvements. Included in this table are approximate estimates of the improvement resulting from the change, the work required to effect it, estimates of outage time that the plant will be down to make changes, and approximate capital costs. These figures are quite approximate, because they actually vary with existing plant conditions.

Feedwater Heater Additions

Addition of one heater improves the heat rate about 285 kJ/kwh (270 Btu/kwh), perhaps 2%. Further heaters would improve the heat rate by a succeedingly smaller amount. Turbine modifications would probably be required.

Reduce Backpressure (Condensing Pressure)

This is accomplished by increasing the velocity of water in the condenser tubes, which results in better heat transfer and thus lower condensing temperature and pressure. The degree to which this improvement can be effected is small. Tubes must be changed to take the higher velocities without erosion, but this is limited. In any case, the increased pumping power would offset part, if not all, of the gain in efficiency.

TABLE B-VII-1
EFFICIENCY IMPROVEMENTS

Modification	Improvement in Heat Rate	Work Required	Outage Time	Cost	Remarks
Add Feedwater Heaters	270 Btu/Htr.	Replace turbine, add heater and piping	8 mos.	$25/kw	For same steam flow the unit output would be reduced by 5%. Charge required for replacement energy.
Lower Back Pressure (Pump more C.W.)	1%/0.5"Hg	Change condenser tubes for higher velocity. Add new circulating water pumps with new intake bays and piping as required.	2 mos.	$6-8/kw	Limit of improvement is in the order 0.25"Hg and any gain would probably be lost to increase pump power.
Increase Steam Temperature	0.8%/50°	Possibility of boiler modification to obtain ±25°F. Some modification of turbine will be required. Main steam piping will have to be replaced.	3 mos.	$6-8/kw	Practical limit for steam temperature is 1000°F. Limitation primarily due to boiler, however turbine also poses problems
		For 50-100°F increase make extensive modification to boiler (or replace) and replace turbine plus steam piping. Turbine pedestal modifications will also be required.	8-16 mos.	$35-50/kw	
Increase Steam Temperature	1450-1800psig =1.7%; 1800-2400psig=2.0%; 2400-3500 psig =1.7%	Replace boiler, turbine, steam and feedwater piping, some changes to feedwater heaters. Modify turbine pedestal and install new feedwater pumps.	16 mos.	$60-80/kw	Increases of 3-5% possible without modification. However, this will not increase cycle efficiency because the turbine is designed for maximum efficiency at rated pressure.
Add Reheat	3-4% for units operating at 1800 psi and above. 2-3% for units operating at 1200-1450 psi	Replace boiler, turbine and hot reheat piping, rebuild turbine pedestal, modify boiler controls, modify condenser and make changes to feedwater heating system.	24 mos.	$100/kw	Typical new reheat unit would be 75MW or less in size and would operate at 1450 psi and 950°F.

Increase Steam Temperature

Small increases might be accomplished with boiler and main steam piping modifications. Larger increases require turbine replacement also. In any case, the maximum steam temperature practical at the present level of technology is about 540°C (1000 °F).

Increase Steam Pressure

Improvements in efficiency of the order shown may be accomplished by increasing steam pressures. However, extensive replacement of much of the plant is required.

Reheat

On lower pressure units, 10,000 kN/sq m (1450 psi and less), the efficiency gain from reheat is less than for higher pressure units, 12,400 kN/sq m (1800 psi and higher). The gains and work required are as shown in Table B-VII-1. The extent of work approaches a complete replacement of the plant.

Increase Cooling Gas Pressure

By increasing the pressure of the hydrogen gas used for cooling the generator, it would be possible to produce slightly more power from the generator, with higher input.

Drain Coolers

Cycle efficiency may be improved slightly by the addition of drain coolers to the existing feedwater heating system, if not already included. Figure B-VII-11 shows this arrangement. The drain cooler takes the hot condensate from the feedwater heater and uses it to preheat the feedwater leaving the condenser. In this way the cycle efficiency is increased slightly.

Drains Pumped Forward

Cycle efficiency may be improved slightly by pumping the feedwater drains forward, instead of draining it back to the condenser. Figure B-VII-12 shows this arrangement. Note that an additional pump is required for pumping the drains.

Superposed Plants

A method of improving the efficiency of older plants that has met with some success is the superposition of a higher pressure and temperature system on top of the existing plant. A new boiler, turbine, feedwater heaters and pumps

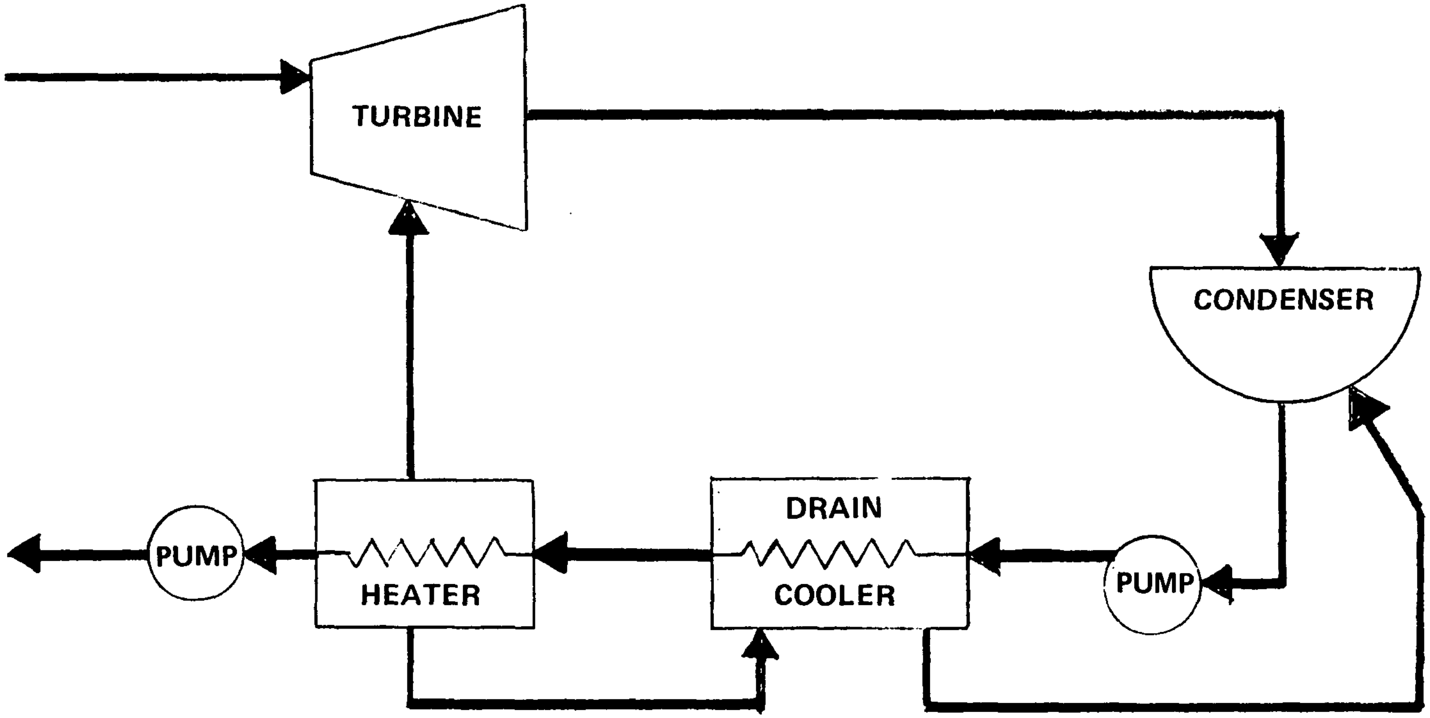


FIGURE B-VII-11 DRAIN COOLER ADDITION TO POWER PLANT

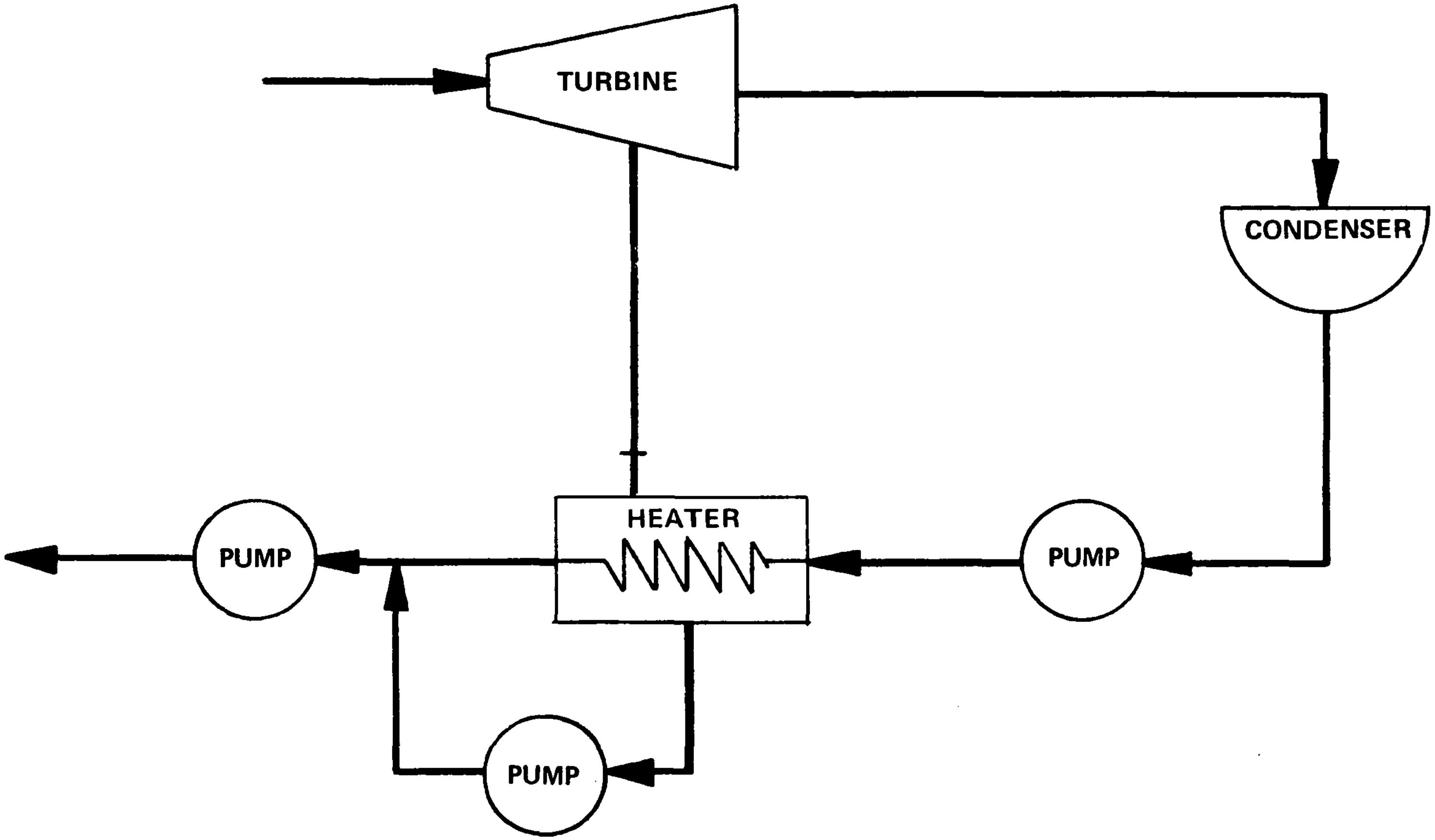


FIGURE B-VII-12 DRAINS PUMPED FORWARD IN POWER PLANT are added to the plant, exhausting steam to the old turbine at its design conditions (Figure B-VII-13). The new boiler may replace the old boiler or supplement it. The advantage of this procedure is that the existing turbine and condenser are retained, and made use of. Economical upgrades of a number of plants were carried out in this way in the 1930's. It is doubtful that this approach would be economically justifiable under existing capital cost conditions.

Complete Plant Upgrading

Consider a typical non-reheat unit, rated at 75 Mw, to be upgraded to get a turbine cycle heat rate of approximately 8,450 kJ/kwh (8,000 Btu/kwh). The following changes would be required:

1. Raise pressure to 16,500 kN/sq m (2,400 psi)

2. Increase superheat temperature to 537°C (1,000°F)

3. Add reheat to 537° (1,000°F)

4. Modify the regenerative feedwater heating cycle

To make these changes, the following work is required:

1. New boiler, turbine and boiler feed pumps

2. New steam and feedwater piping

3. New boiler controls

4. New feedwater heaters

5. Add cold and hot reheat piping

6. Rebuild the turbine pedestal

7. Modify the condenser

8. Modify parts of the turbine building and rebuild the boiler building

The cost of all this work would be at least as much as that of a new plant, as that is what it involves. It is estimated that a 2-3 year plant outage would be required for the work.

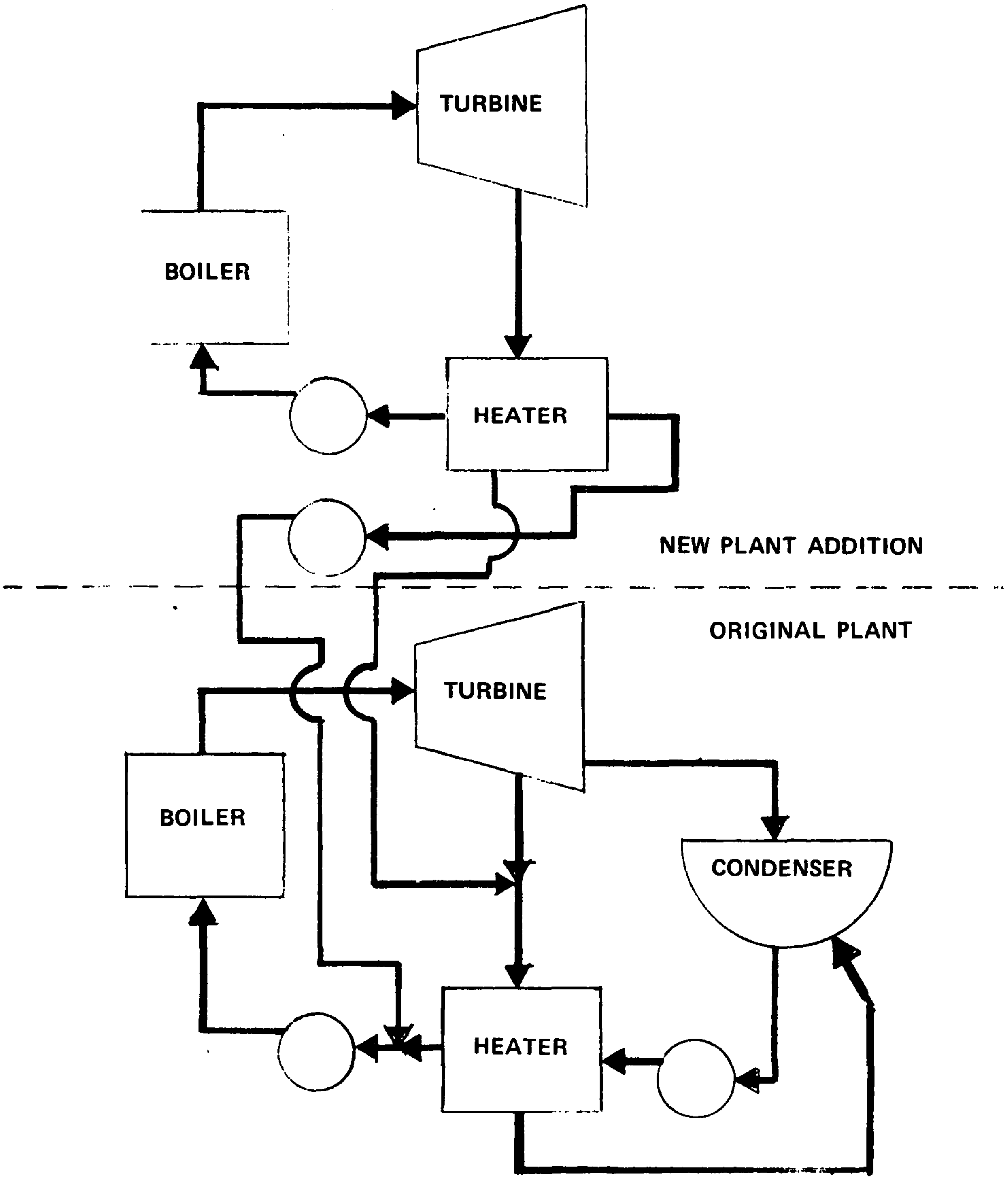


FIGURE B-VII-13 SUPERPOSED PLANT ADDITION

Future Improvements in Present Cycles

At the present time, maximum steam temperatures are limited to about 537°C (1,000°F). Temperatures above this requires changes in the type of steel used in boiler tubing, piping and in turbines that greatly increase plant costs. There is a general consensus in the utility industry that significant increases in steam temperature are not forthcoming in the immediate future.

Most of the average size units being installed at the present time, in the 300 to 600 Mw size range, are at a pressure level of around 17,200 kN/sq m (2,500 psi). A significant increase to supercritical pressures, around 24,100 kN/sq m (3,500 psi) is being used for some of the larger units. A cycle efficiency improvement of about 1.5 to 2.0% occurs with this pressure increase.

Gas Cycles

In addition to the steam vapor powerplant cycle, gas cycles may be considered for generating electric power. These plants usually operate on the Brayton (Joule) cycle or some modification of this cycle. Figure B-VII-14 indicates an arrangement of components, and the gas flow.

Air is drawn into the compressor. After compression the air flows to a combustor where a gaseous or liquid fuel is burned in the air. The products of combustion at high temperature and pressure flow through the turbine and generate power. This cycle may have a relatively low thermal efficiency, even though heat is added at a relatively high temperature. This is because the gases discharged from the turbine are still at a quite high temperature. To overcome this a regenerative heat exchanger is added to the cycle, as shown in Figure B-VII-15.

The effect is to preheat the compressed air before combustion, utilizing the waste gas, thus increasing cycle efficiency.

Further refinements can be made by adding intercooling between compressor stages and by reheating, using a second combustion chamber. With these refinements the efficiency of the cycle may increase further.

Gas cycle power generation precludes any significant thermal wastewater, as the main effluent is a gas.

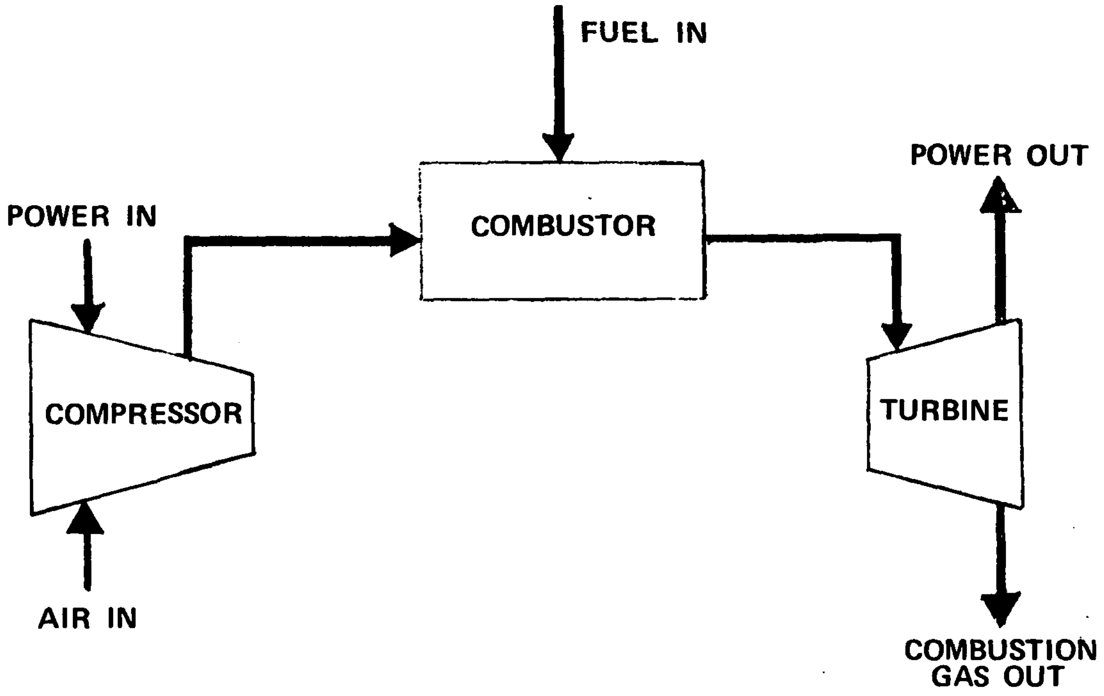


FIGURE B-VII-14 SIMPLE BRAYTON CYCLE GAS TURBINE POWER PLANT

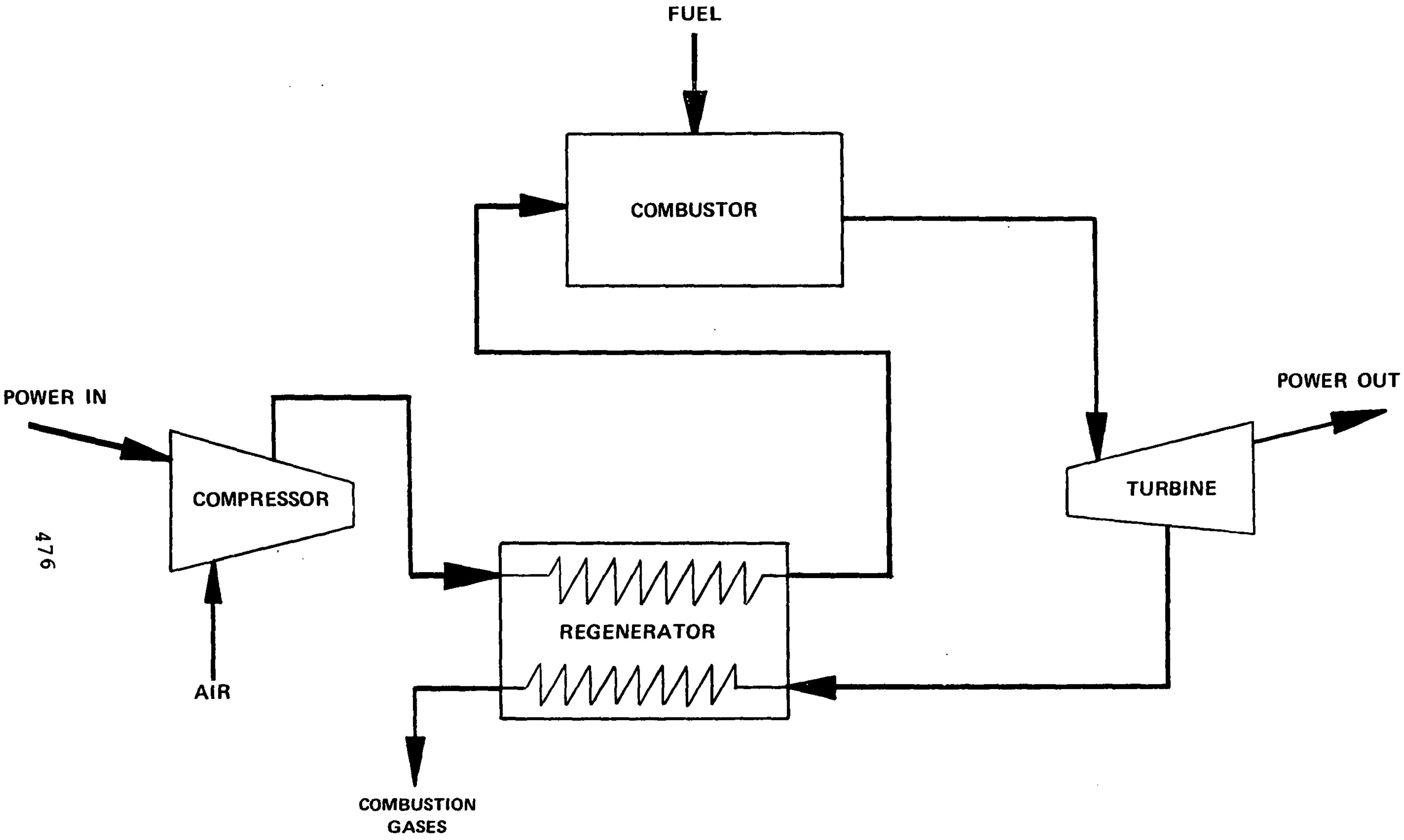


FIGURE B-VII-15 BRAYTON CYCLE WITH REGENERATOR GAS TURBINE POWER PLANT

Gas Cycle Plants - Base Power

Plants using gas cycles are used for base power today only in special applications. The cycle efficiency does not equal that of the steam vapor cycles. Gas turbines are not available in sizes adequate for the larger units of present powerplant design.

Present development of turbines and other plant components to withstand higher temperatures may make the gas cycle more attractive in future decades.

Gas Cycle Plants - Peaking Power

The gas turbine cycle is used today for purposes of peaking power. The structure of some power system loads is such that there is a base load plus short term requirements for peaks above that load. A gas turbine plant addition is a natural consideration for this use. A relatively inefficient cycle can be used, because of the short periods of use. The incremental capital cost of the plant addition is low.

The result of this arrangement is no increase in the thermal wastewater discharge for the additional power generated. However this holds only for the incremental power and only during the short time period that the peaking equipment produces this power.

Combined Gas - Steam Plants

An efficient combination can be obtained by utilizing the high temperature at which heat is added to the plant in the gas cycle and the low temperature at which heat is rejected from the plant in the steam cycle. An example of the plant component arrangement is shown in Figure B-VII-16.

The combined cycle has proven advantageous as a method of up-grading existing older steam plants. Usually the situation is one where the existing boilers need replacement or very extensive rebuilding. The efficiency of the existing plant is usually not high, as the steam temperatures and pressure are considerably lower than those possible today. The modernization procedure usually consists of replacing existing boilers with gas turbine exhaust heat boilers which supply steam to the existing steam turbines. The overall plant efficiency of such an arrangement might increase 5 to 10%, thereby reducing the thermal discharge correspondingly.

Plant No. 3708 has up-graded part of its plant with such a combined system. The result has been to reduce the heat

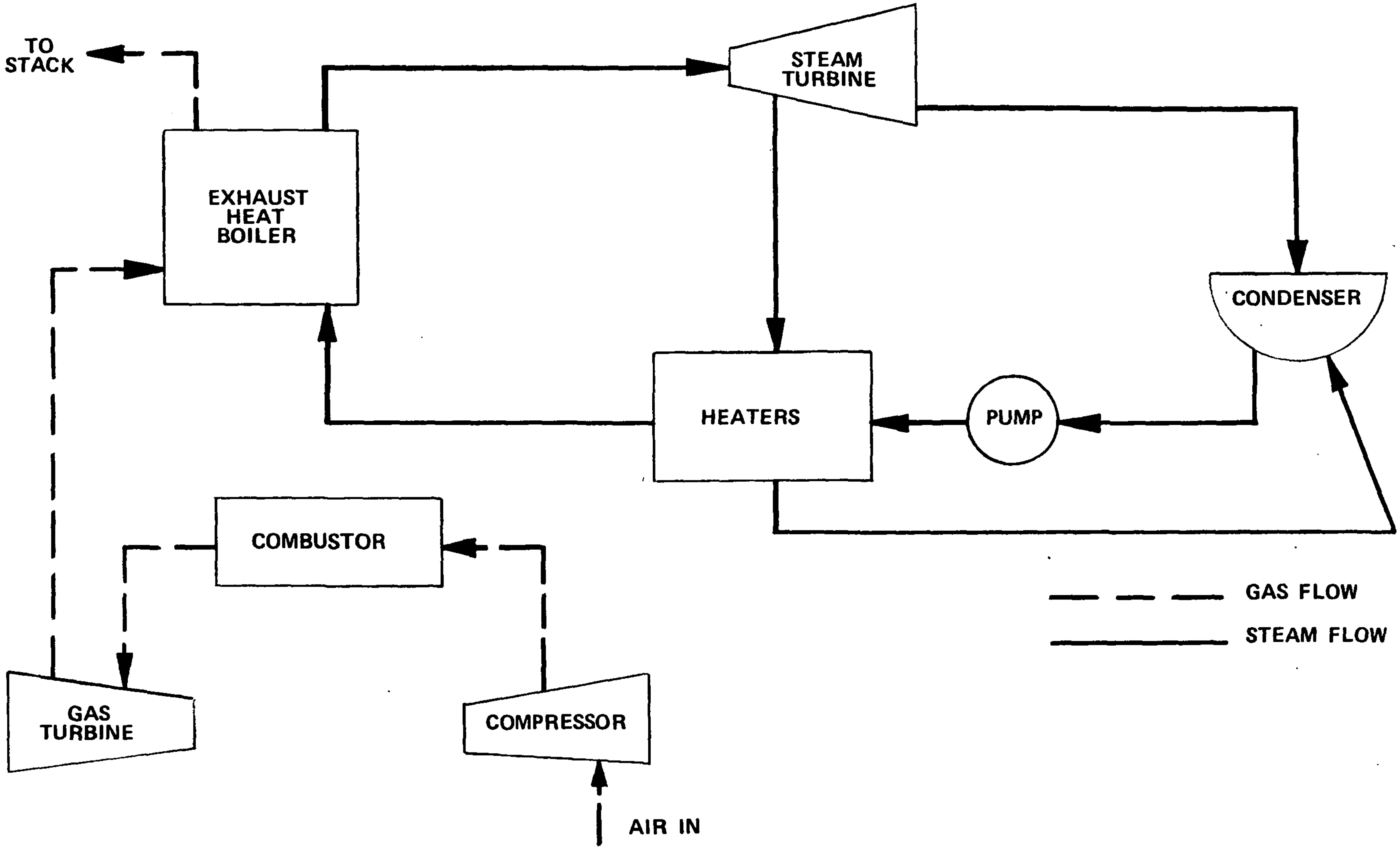


FIGURE B-VII-16 COMBINED GAS-STEAM POWER PLANT rate on that part of the plant from 14,770 kJ/kwh (14,000 Btu/kwh) to 11,610 kJ/kwh (11,000 Btu/kwh).

The combined gas-steam cycle has also been chosen in some new plants recently. The overall plant efficiency is approximately the same as that which would be achieved with a modern steam plant. However, gas turbines that will withstand significantly greater temperatures are expected to be available within a few years. Higher temperatures are already in use in aircraft gas turbines, and the spin-off in technology should follow as it has previously. This is estimated to result in cycle efficiency improvements of 5 to 10% for the next generation of combined gas-steam plants over the best steam plants today. The present design of steam plants is not expected to improve by a similar increase of temperature. Technological improvements in boilers to match those of gas turbines are not expected. If such developments occured,
it seems likely that the resultant steam plant would not economically compete with the combined plant.

Future Generation Processes

Binary Topping Cycles

With steam vapor cycles, much of the heat is added to the plant at lower temperatures than the maximum possible. This heat is largely used to evaporate the water. Vaporization of water cannot take place above 374°C (705°F), therefore this inefficient heat addition process cannot be avoided.

To overcome this defect, plants using two fluids, each in a separate cycle, have been conceived. An example is the mercury-steam binary cycle. Mercury is used in the topping cycle, steam in the bottom (lower temperature) cycle. Heat can be added to the mercury at practically the highest temperature metallurgically permissible. A few powerplants have been constructed using this arrangement.

Although this cycle has an inherently higher efficiency than with the steam cycle alone, serious disadvantages have led to its demise. Mercury is extremely expensive and highly toxic. Some operating problems were not satisfactorily resolved in the plants built. Theoretical interest has been shown in using other fluids for the topping cycle (e.g., potassium) but developmental work has been limited.

Geothermal Steam

Geological conditions in certain locations provide a natural source of steam from the earth's heat. The steam can be used in a conventional power turbine. The thermal discharge rejected from the plant has less internal energy than the steam, so there is a net negative thermal discharge. However, the disposed waste heat could still be in an objectionable form and location. The use of this power source is practicably confined to only a few locations on the earth, and thus does not affect thermal discharges generally.

MHD

Magnetohydrodynamics (MHD) is a principle of producing power quite different from the steam cycle. An electrically conducting hot gas is moved at high velocity through a magnetic field, a procedure that directly generates electricity in a surrounding coil. The present status of this phenomenon for power production is in experimental development stages only.

Fuel Cells

The efficiency of a fuel cell is not limited to that of the Carnot cycle, as it does not receive its energy by means of conversion of heat energy to work. Energy is converted directly from chemical to electrical energy. Fuel cells have been commercially developed for certain applications in small power requirements, but at the present time there is no prospect for large units on the scale of steam powerplants.

Waste Heat Utilization

There are three ways in which heat produced by powerplants might be utilized in an alternate manner to reduce the amount of heat rejected to receiving waters. These alternate heat consuming methods are as follows:

- utilization of low-grade heat

- utilization ot extraction steam

- total energy systems

Utilization of low grade heat

This process means the use of the condenser cooling water in the condition it is in as it leaves the condenser. Using low-grade heat in this manner is desirable because no modification to plant performance is required. The disadvantage of this type of system is that the heat content of the condenser water that is useable is small and large volumes of water must be transported to get a significant quantity of heat. Of the several systems of low-grade heat utilization in operation or in various stages of development, most are agriculturally or aquaculturally oriented. The findings of some of these programs are discussed below.

Agricultural Uses

A considerable amount of related work has been planned by the Tennessee Valley Authority. TVA has set aside 72.8 ha (180 acres) of land at a major nuclear installation (Plant No. 0113) for the testing of various ways of using waste heat.

The initial effort at the TVA plant will be concentrated on the development of greenhouse technology for the production of high value horticultural crops utilizing the condenser discharge water for both heating and cooling. The information on these programs has been taken from Reference 353. Initial tests will include conventional greenhouse crops such as lettuce, tomatoes, cucumbers, and radishes. Later work will include such crops as strawberries for the fresh out-of-season market. Eventually, a mix of crops which fits well in sequence during the year with production and marketing conditions and which grow well in the greenhouse climate will be determined.

Preliminary calculations have been made of several crop combinations to obtain an estimate of the potential sale value per acre of greenhouse. The data indicate gross sale potential of from $40,000 to $60,000 per 0.405 ha (acre) per year is obtainable depending on crop mix. The savings in fuel cost alone in utilizing the waste heat in this manner may be upwards of $10,000 per 0.405 ha (acre) per year. Calculations show that the development of 13.0 ha (32 acres) of greenhouse tomato production and 23.5 ha (58 acres) of lettuce would utilize about 6% of the available condenser water at the plant, and provide about 1.4% of the total requirements for these products in the Southeast. The lettuce production would amount to 30 percent of that now shipped into the combined Atlanta, Memphis, Nashville, and Birmingham markets. TVA is also planning other projects for agricultural use of waste heat for subsurface heating of the ground, and also utilizing the greenhouse concept for the raising of pork and poultry. These programs are not very far advanced at this point.

A similar study of greenhouse use of waste heat has been performed by the AEC and is reported in Reference 351. This study centered on the use of waste heat from a new high-temperature gas-cooled reactor located in the Denver vicinity. The study concluded that the cost of equipment required to utilize the warm water was in the range of the cost of heating systems for conventional greenhouses. Since the cost of heating greenhouses in the Denver area is over $5,000 per year, the potential value of the heat being wasted is greater than $1,000,000 per year.

Aquaculture

The use of low-grade heat to improve the yields and productivity for fish and seafood species is called aquaculture. Basic data indicate that catfish grow three times faster at 28.3°C (83°F) than at 24.4°C (76°F). Similarly, shrimp growth is increased by about 80% when water is maintained at 26.6°C (80°F) instead of 21.1°C (70°F).

Several commercial operations of this type are in existence in the U.S. utilizing waste heat from powerplants. A commercial oyster farming operation is in existance on Long Island, N.Y. using the thermal effluent from powerplant No. 3621. Normal growing periods of four years have been reduced to 2.5 years by selective breeding, spawning, larvae growth and seeding oysters in the hatchery. This avoids reliance on variable natural conditions and permits accelerated growth in the thermal effluent discharge lagoon over a period of about 4-6 months when the water would otherwise be too cold for maximum growth. The product is marketed for $15-20/bushel (1971) which is the upper end of the wholesale price range.

Catfish have been cultured in cages set into the thermal discharge canal of a fossil-fueled plant (plant No. 4815) located in Texas. During the winter of 1969-70 growth rates achieved were equivalent to 200,000 lb/acre-year. This is comparable to the yields of rainbow trout culture in moving water. The Texas operation is now on a commercial basis.

TVA also operates a small-scale catfish raising facility at its waste heat complex. Results from the first year's operation confirmed that the growth rate of the catfish was significantly enhanced by the addition of the heated water and that the growing season was significantly lengthened. However, several problems prevented expansion to a commercial scale operation. Feed loss and mortality rates were high. Water quality studies showed that high intensity production of catfish generated substantial quantities of waste material and that the equivalent of secondary treatment would be necessary before the facilities could be expanded.

The major weaknesses of low-grade heat utilization are the following:

1. Inability to utilize large quantities of total waste heat available. This is due not only to the capital requirement but also to the fact that the product is produced in such quantities that it may exceed market demand.

2. Uses are seasonal which require either the dumping of waste heat in the off season or the building of a cooling tower in addition to the waste heat utilization systems.

3. Inability to provide needed heat when plant is shut down and unadaptability of the cultured organisms to rapid temperature change.

Utilization of Extraction Steam

Extraction steam utilization increases both the number and the size of the potential heat users. Table B-VII-2 following shows the total annual energy demand by several types of heat using processes in the United States. The table is taken from Reference 24.

The most notable extraction steam heating system is located in downtown Manhattan, in which approximately 300 Mw of heat is supplied from extraction and back pressure turbines. This system has been in operation for many years. District heating systems of this type are expected to increase in usage in those places where it can be marketed successfully for operation of large tonnage air conditioning loads.

Extraction steam heat utilization is also used to supply industrial process steam. The classic case of extraction steam utilization for industrial process steam takes place at powerplant No. 3414 located in the Northeast. This plant supplies the bulk of the process steam to an adjacent oil refinery. The plant was designed with this capability in mind. The alternate utilization scheme increases the efficiency of the generation cycle from 34% to 54%. This is equivalent to reducing the waste heat rejected to the environment by 25%.

Table B-VII-2

ENERGY DEMAND BY HEAT USING APPLICATIONS (1970)[24]

Application	Supply Temperature, °F	Energy Used, trillion Btu
Electricity	-	4,000
Space Heat	200	6,000
Domestic Hot Water	200	1,000
Industrial Steam	300-400	5,000

Another form of extraction steam utilization is the use of steam to desalt saline or sea water. This type of use is common in arid locations and also in many of the small islands in the Caribbean. Unfortunately, the quantities of heat consumed by water desalting processes are relatively small. The largest water desalting plant in operation today has a capacity of only 5.0 million gallons of water per day. This would require much less than 1% of the waste heat from a new 1,000 Mw nuclear plant.

The major disadvantage of extraction steam methods is the necessity of combining the plant and the adjacent steam utilizing process to determine the overall performance of the system. In addition, it is difficult to balance the often variable steam requirements with the power production process.

Total Energy Systems

The total energy concept seeks to overcome some of the obvious shortcomings of the low-grade and extraction steam utilization concepts by aggregation of all energy consuming interests in a well defined area. Most total energy systems in the United States are relatively small, consisting of individual shopping centers, educational complexes and industrial complexes. The total energy concept is practiced more intensively in Europe.

A major study conducted by the Oak Ridge National Laboratory, Reference No. 350, tested the economic feasibility of a large energy system serving a hypothetical new town of 389,000 people. The climate of the new town was similar to that of Philadelphia, Pa. The system provided in addition to electricity, heat for space heating, hot water, and air conditioning for the commercial buildings and portions of the apartment buildings. Heat was also available for manufacturing processes and desalting of sewage plant effluent for reuse. The study concluded that it would be possible in the 1975-1980 period and beyond to supply low cost thermal energy from steam electric powerplants to new cities, especially those in the population range of 200,000 to 400,000. With respect to climate, the cities could be located anywhere in the continental United States except perhaps in the most southern portions.

The use of thermal energy extracted for the turbines of the generating plants would be economically attractive. For example, in one configuration of a 1980 city with a population of 389,000 people and a climate similar to that of

Philadelphia, Pennsylvania, the cost of heat for space heating and domestic hot water was estimated to be approximately $1.98/MBtu.[355] This system was considered to be competitive in that its use would result in an approximately equal cost compared with other systems. It is anticipated that interest in total energy systems will increase as the rapidly increasing cost of fuel will require corresponding increases in the efficiency of fuel consumption.

Cooling Water Treatment

General

Steam electric powerplants employ four types of circulating water systems to reject the waste heat represented by the difference between the energy released by the fuel and the electric energy produced by the generators. These systems are the once-through system, once-through with supplemental cooling of the discharge, closed systems, and combinations of the three systems. In a once-through system, the entire waste heat is discharged to the receiving body of water. The applicability of this system is dependent on the availability of an adequate supply of water to carry off the waste heat and the ability of the receiving body of water to absorb the energy. There is no reduction of total waste heat energy being discharged by the plant in a once-through system.

A once-through system with supplemental cooling removes a portion of heat energy discharged by the plant from the plant effluent and transfers this energy directly to the atmosphere. Various devices are used to achieve this transfer. A long discharge canal could be a cooling device. If a sufficient surface area is not available, the rate of evaporation per unit area may be increased by installing sprays in the discharge canal. If sprays do not provide sufficient evaporative capacity, cooling towers may be utilized in the supplemental cooling mode. The amount of heat that can be removed from the circulating water discharge is a function of atmosphere conditions and the type and size of the cooling device provided.

Recirculating cooling water systems provide a certain type of design and operational flexibility leading to lower costs that is not available with helper systems. The costs of cooling devices are related to their size. The use of higher cooling water temperatures allows for the use of smaller, less costly cooling devices to transfer the same amount of waste heat to the environment. The recirculation to the condensers of all, or a part, of the cooling water leaving a cooling device (if its temperature exceeds intake cooling water temperature) would elevate all temperatures in the system. The result would be that, for a fixed system, more waste heat would be transferred to the atmosphere, or, for a fixed waste heat load, a smaller and less costly cooling device could be used. In any case, the added or reduced costs due to changes in the energy conversion efficiency brought about by the changed recirculation temperatures would become significant in relation to the extent of the temperature changes involved. A further cost savings of recirculating cooling water systems would be attributable to the small intake and discharge structures.

A further characteristic of helper systems is that they are designed primarily to reduce the temperature of the water discharged and not the amount of heat discharged. When recirculation of a portion or all of the cooling water is practiced, the temperature of the discharged water is actually increased (compared to operating in the helper mode) but the effluent heat is reduced (compared to the helper mode) because of the reduction in discharge volume.

Closed circulating water systems are currently in common use in the industry, although in the past the reason for employing closed systems has seldom been the elimination of thermal effects, but rather the lack of a source of water supply adequate for a nonrecirculating system.

The following section describes each of these systems in further detail.

Once-Through (Nonrecirculating) Systems

These are defined as those systems in which the water is removed from the water source, pumped through the condenser in one or more passes to pick up the rejected heat, and then returned to the water source. These systems are arranged so that the warm water discharged to the receiving body of water does not recirculate directly to the intake point. Oncethrough systems have been the most prevalent in the United States to date. In general, other systems have been used only when sufficient water for once-through operation has not been available. The trend has been away from the use of once-through systems. Only about one-half of all new units are committed to once-through systems, whereas about 80% of all existing systems are once-through.

The basic design of the once-through, or open, system is shown in Figure B-VII-17. The purpose of the intake structure has generally been to prevent trash, fish, grass

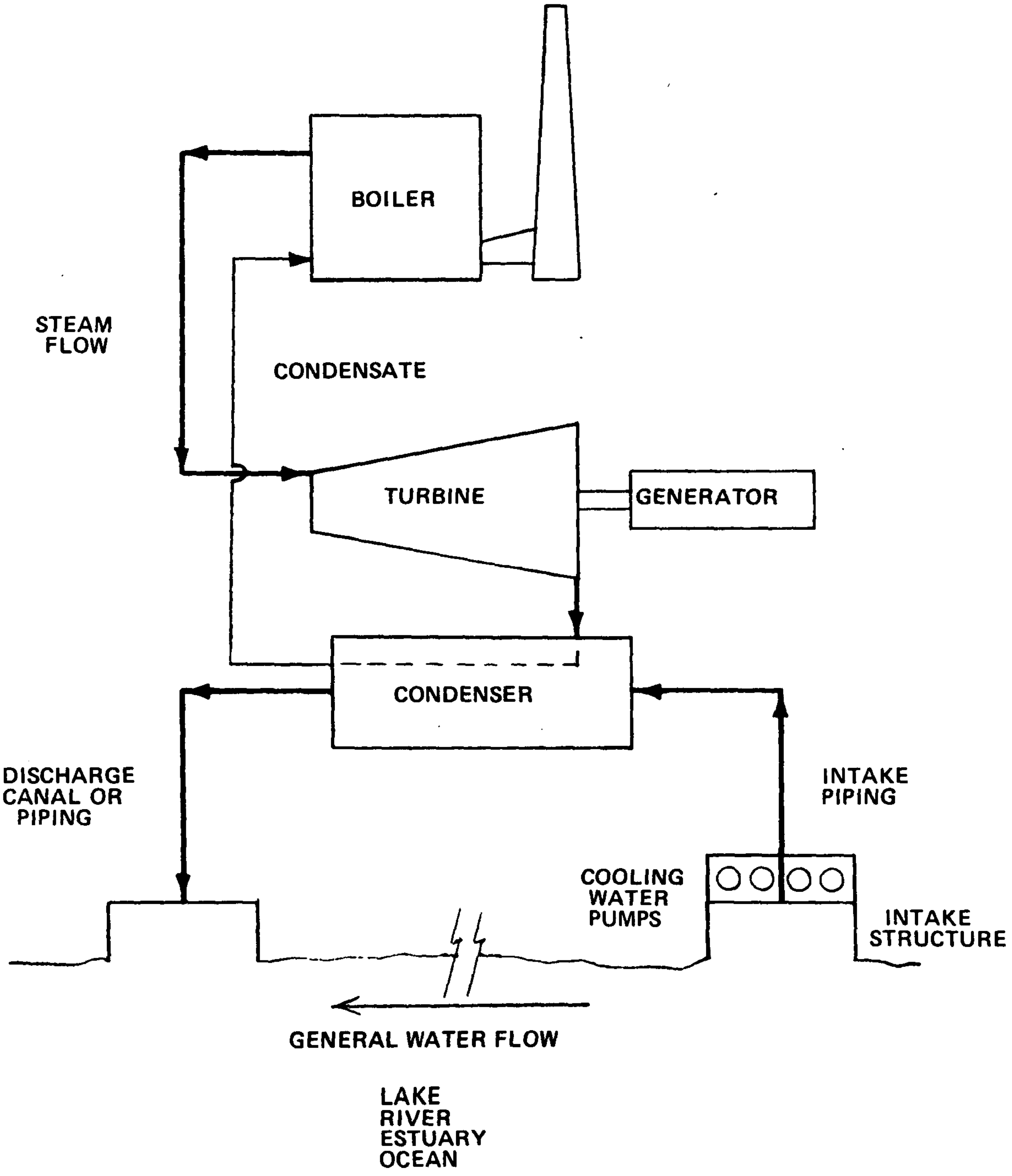


FIGURE B-VII-17 ONCE THROUGH (OPEN) CIRCULATING WATER SYSTEM and other materials from entering the condenser and either plugging or damaging the condenser tubes, resulting in decreased performance or shut down of the unit for repair of condenser tubes. In some cases skimmer walls are used to insure drawing cooling water from deep in the supply source, where the water is colder. The pumps required to circulate the water through the condenser are normally located at the intake structure. Normally there are several pumps for each unit, due to the large flows involved and due to the requirement of providing a higher degree of flexibility and safety in the operation of the cooling water system. Flows for a single unit can exceed 30 cu m/sec (500,000 gpm), and some of the large stations require over 60 cu m/sec (1,000,000 gpm). The total annual use of cooling water by steam electric powerplants is an amount equivalent to about 15% of the total flow of all rivers and streams in the U.S. The cooling water flow rates in some plants is comparable to the flow rates cf some rivers.

The discharge from the condenser can be returned to the source via a canal or pipe, depending on the local conditions. The discharge structure serves two purposes. The first is to return the water in such a manner that damage to the stream bank and bottom in the immediate vicinity is minimized. The second is to promote the type of thermal mixing required. On lakes or estuaries where water velocities are low, considerable separation between the intake and outlet structures is required to prevent warm water from recirculating directly into the intake.

When compared to closed systems, the water temperature of the circulating water in the open system tends to be lower, thereby sometimes allowing a higher generating efficiency for the plant with the open system. Plant No. 3713 has one of the best heat rates in the country, due, in part, to the low inlet water temperature, which does not exceed 24°C (75°F), during the summer months. This is discussed in more detail under closed systems. As a result of the above, the best

plant efficiencies are generally obtained with once-through systems.

Once-Through Systems with Supplemental Heat Removal (Helper Systems)

With the development of the larger generating stations, it has been determined in some cases that the large amount of heat rejected to the environment by cooling water discharged from these stations could seriously affect the water environment. Consequently, in those cases, the utilities have been required to re-evaluate their thermal discharge systems. One consideration short of recycling condenser cooling water would be to remove heat from the nonrecirculating system prior to discharge to the environment. This would be accomplished by a cooling device placed in the circuit between the condenser and the discharge point, as shown in Figure B-VII-18 to divert some heat directly to the atmosphere. The amount of heat that could be removed by such a device operating at full capacity would be dependent upon the atmospheric or climatic conditions, principally wet bulb and dry bulb temperatures, or even wind velocity, solar intensity, and cloud cover, depending on the type of device used.

Since these heat removal systems are also applicable to closed systems, they will be discussed here in general terms only. The design and operation of each of the systems is covered in detail under the closed systems section. Special considerations only are covered in this section. In general, limiting climatic conditions are such that while a majority of the heat can be removed, the discharge stream temperature will always be higher than the receiving water at the discharge point.

The systems considered for this end of pipe, or helper mode of thermal discharge control are cooling towers, both natural draft and mechanical draft, and ponds or canals which can contain floating powered spray modules to augment the natural cooling process. The known installations tend to be designed for operation in any one of several alternative modes. For example, Plant No. 2708 (Ref. No. 108dd) employs a mechanical draft evaporative cooling tower system capable of (a) off-line, (b) helper, (c) partial recirculating and (d) closed-cycle modes of operation that is expected to be capable of meeting water quality standards.

Diagrams of two systems presently in use are shown in Figures B-VII-19 and B-VII-20. The system in Figure B-VII-19 can be operated in both open and closed modes. The system shown in Figure B-VII-20 is much more complex. Units 1 and 2 were originally once-through. When Unit 3 was added, a once-through system could not be used due to low water availability in the summmer.[359] In designing the closed cooling tower system for Unit 3, it was decided to add one additional tower, which would permit operation of all three units on an almost closed system during the summer when the temperature of the discharge to the river is severely limited by environmental protection considerations. The systems illustrated indicate the degree of flexibility

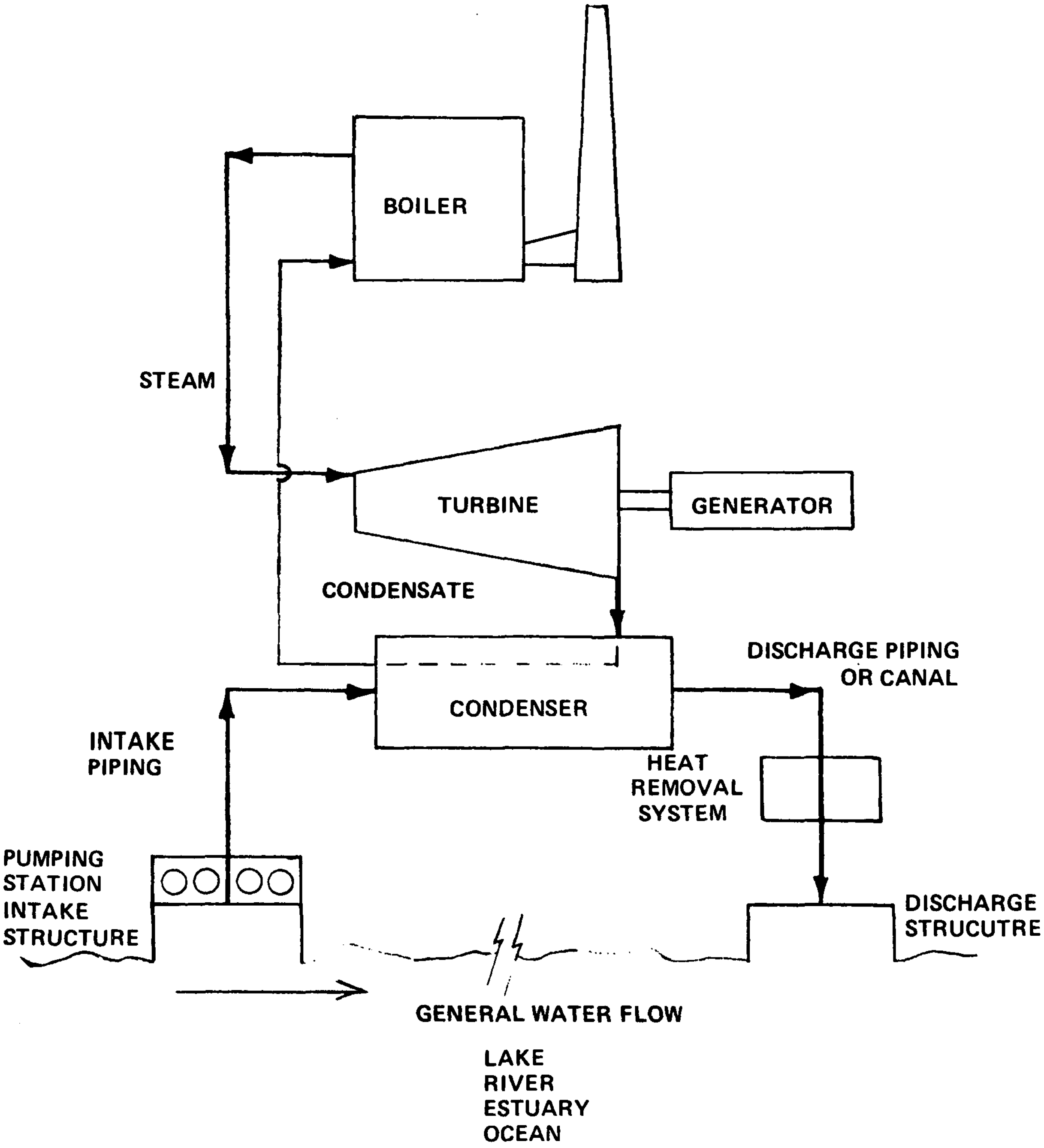
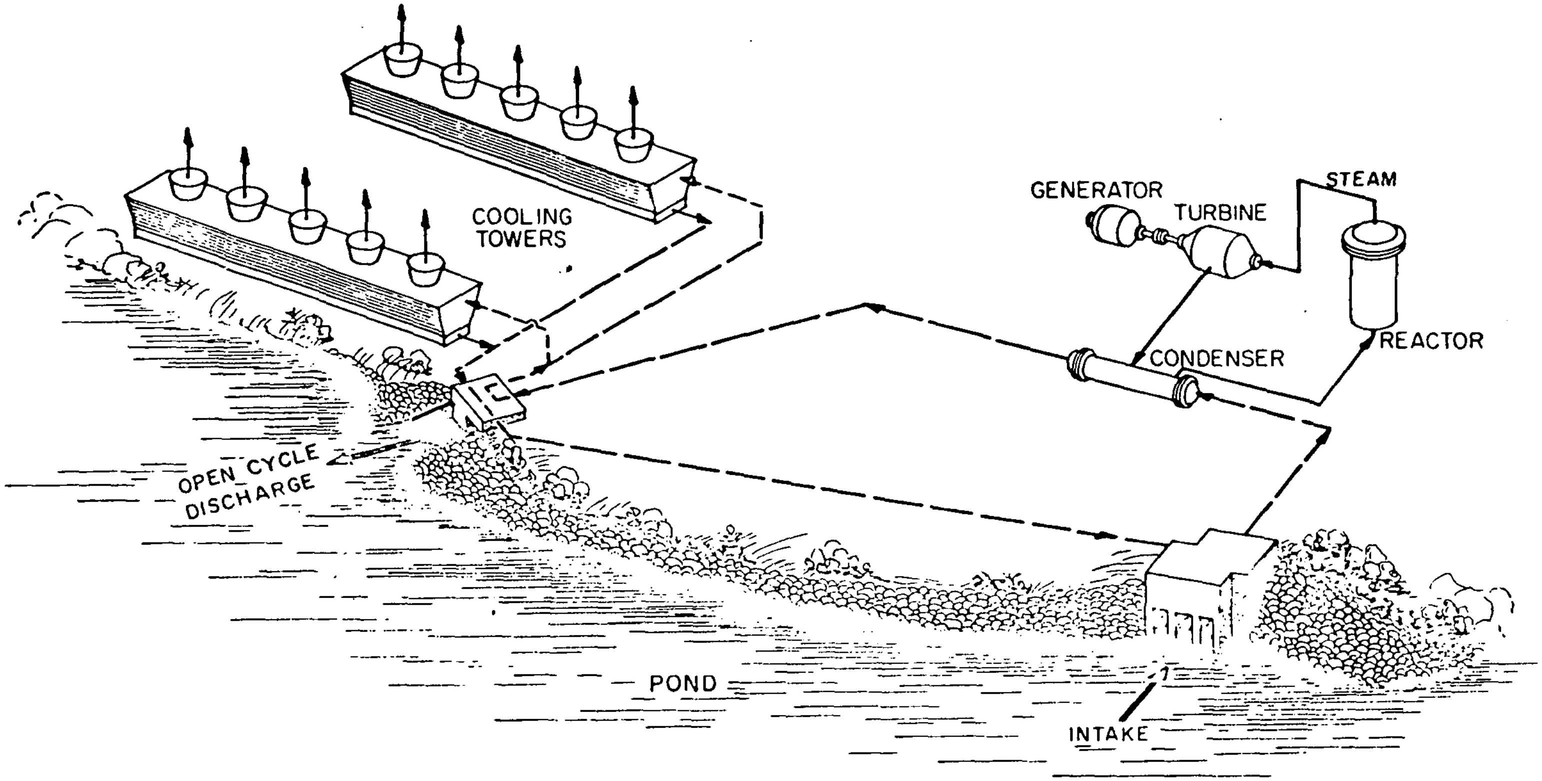
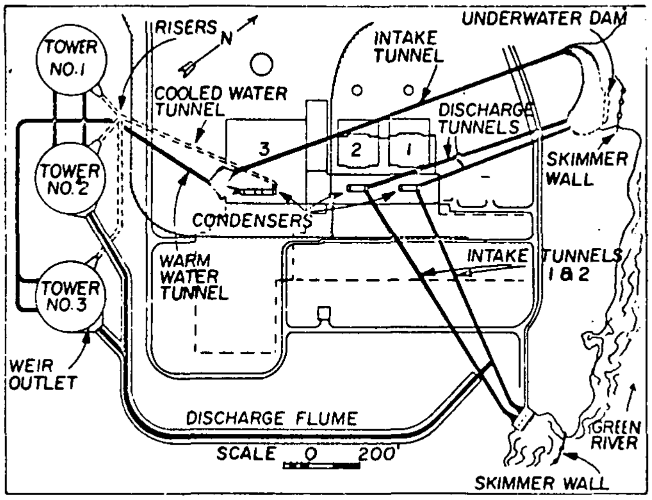


FIGURE B-VII-18 ONCE THROUGH (OPEN) SYSTEM WITH HELPER COOLING SYSTEM INSTALLED



COOLING SYSTEM CAPABLE OF BOTH OPEN
AND CLOSED MODE OPERATION
(Ref. 108z)
FIGURE B-VII-19



PLANT LAYOUT AT PLANT No. 2119
(From Reference 359)
FIGURE B-VII-20

which can be built into a once-through system by using supplemental heat removal systems.

The seasonal variability of the performance of a helper system is shown in Figure B-VII-21. This curve shows the average monthly performance of a tower located in the East, and designed to remove 100% of the heat in September. The circulating water temperature rise was assumed to be 11°C (20°F). With a stream temperature of 27.2°C (81°F), the approach was 4.5°C (8°F). During the month of March, with a stream temperature of 5.6°C (42°F) and a wet bulb of 7.8°C (46°F) the same tower removes only 22.5% of the heat, even though the approach has increased to 6.4°C (11.5°F).

This decrease is due to the variation in relationship between stream temperature and wet bulb temperature. In the summer the stream temperature is well above the wet bulb temperature. In winter, in this location, the stream temperature drops below the wet bulb temperature. In addition, tower performance is lower at the lower winter temperatures.

This obviously poses a problem in the design of towers for "helper" use. In the case shown, a tower designed to remove 100% of effluent heat under the worst winter condition (March) would be over-sized by a factor of 4 during most of the summer.

There is a relatively simple solution to this dilema, and that is to partially close the system during the winter months. Part of the warm circulating water would be recirculated into the intake stream, increasing its temperature. This would increase the discharge temperature, and consequently the water temperatures in the tower. This in turn would increase the difference between the water and the wet bulb temperature and increase the amount of heat removed. The water not recirculated would be discharged. A problem then arises in that the water discharged would have a temperature significantly above the stream temperature. This temperature might not meet applicable stream standards, which would mean operation of the tower in two modes: open in summer and closed in winter. The tower would be designed to handle the heat load under the more difficult of the two operating conditions.

All evaporative type cooling systems would have this decrease in heat removal performance during winter months when operated in the "helper" mode.

One other system should be mentioned in this section. This is the dilution system to limit the temperature effect of

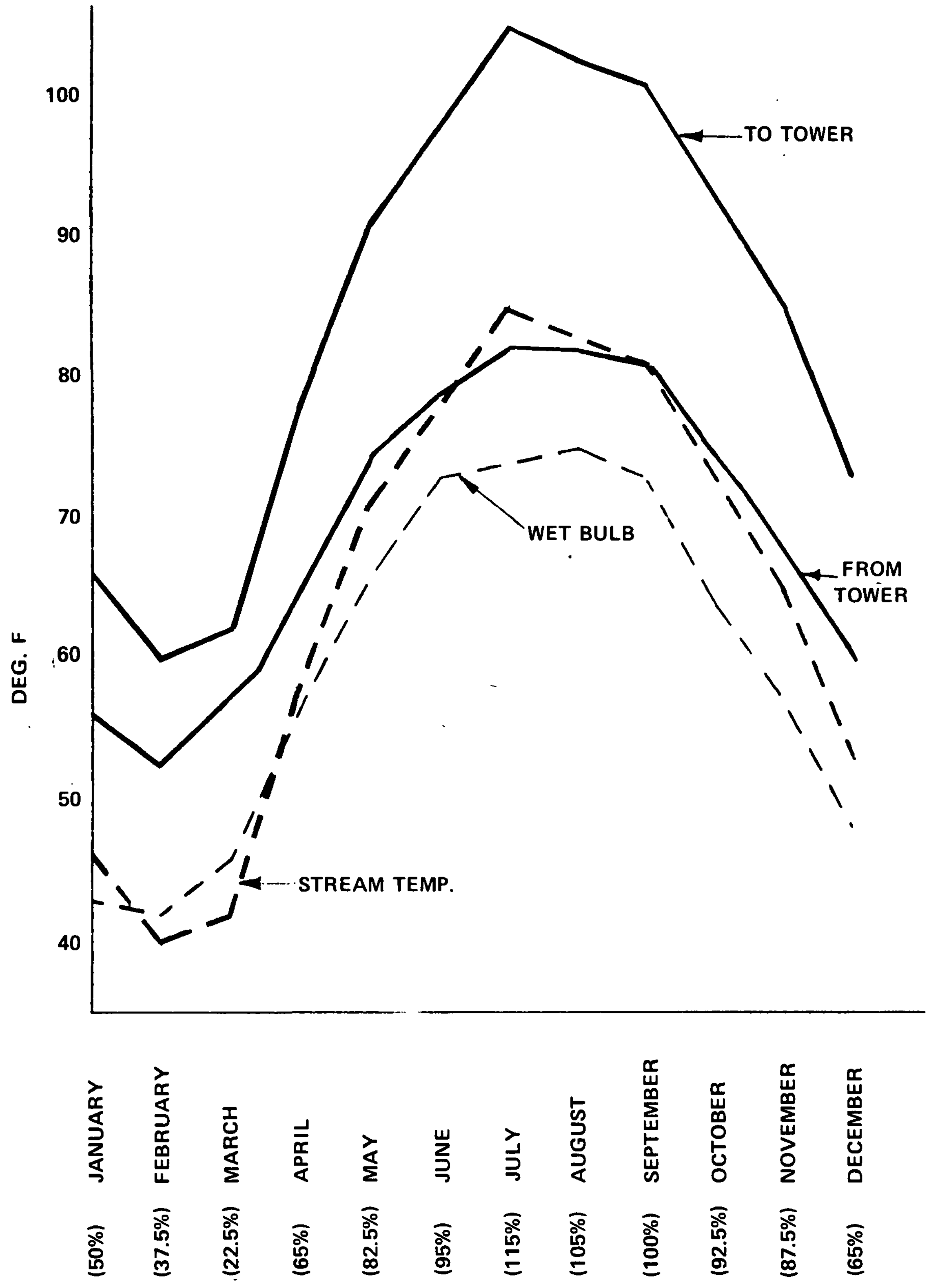


FIGURE B-VII-21 SEASONAL VARIATION OF "HELPER" COOLING TOWER (FROM REFERENCE 74) the discharge on the water to which it is discharged. In this method an excess of water, above the quantity required in the condenser is pumped through the intake system, with the excess being mixed with the hot condenser effluent prior to discharge into the receiving water. While this dilution reduces the combined discharge water temperature, the amount of total heat discharged to the water is slightly greater due to the added generation (and heat rejection) required to power the dilution pumps.

Closed or Recirculating Systems

Closed systems recirculate water first through the condenser for heat removal, and then through a cooling device where this heat is released to the atmosphere, and finally back to the condenser. Three basic methods of heat rejection are used. The one of most commercial significance in the power industry is wet, or evaporative cooling using cooling towers, or spray augmented ponds. Evaporation at 5 x 10^5 J/kg (1,000 Btu/lb) is the principal means of heat transfer. There is also some sensible heat transfer. A second method of closed system cooling commonly employed is the use of cooling lakes, which are similar in principal to open, once-through systems, but which are closed inasmuch as no significant thermal discharge occurs beyond the confines of the lake. Dry cooling towers, in which heat is transferred by conduction and convection, have found very limited use.

The following subsections describe the available technology for achieving waste heat removal in closed or recirculation cooling systems.

1. Cooling ponds or lakes
2. Spray augmented ponds
3. Canals with powered spray modules
4. Rotating spray system
5. Wet tower, natural draft - crossflow
6. Wet tower, natural draft - counterflow
7. Wet tower, mechanical forced draft
8. Wet tower, mechanical induced draft, crossflow
9. Wet tower, mechanical induced draft, counterflow

10. Dry tower, direct

11. Dry tower, indirect

12. Combined wet-dry mechanical draft tower

The effects of the number of cycles of concentration in the operation of closed-cycle (recirculating) cooling towers on the percentage reduction of effluent heat compared to once-through cooling is given in Table B-VII-7 and compared to once-through "helper" assisted systems in Table B-VII-8.

Cooling Ponds

Cooling ponds are normally artificial lakes constructed for the purpose of rejecting the waste heat from a powerplant. A secondary purpose for which the pond is utilized is the storage of water for plant operation during periods of low natural availability of water. This dual usage makes cooling ponds economical in the more arid areas of the country. There are also a significant number of cooling ponds in use in the southern part of the United States. While cooling towers could be used to provide cooling in conjunction with a storage pond, the consumptive use of water in the cooling tower, plus the losses from the water storage pond, is generally greater than the losses from a dual purpose pond.

Two distinct types of ponds can be identified, based on the legal means in which discharge is defined. The first is a pond located where there is little or no natural drainage, or where the water rights on the watershed belong solely to the utility company, and there is no thermal discharge from the pond. In this case, the cooling pond is considered to be completely under the control of the utility company, and the pond is operated solely to give the best plant performance. The cooling pond at plant No. 3514 is an example of this type. While the pond itself may not come under thermal discharge regulations, any chemical discharges (blowdown) from the pond will. In addition, any other effects of the cooling lake on the environment would also have to be taken into account.

The second case is where the pond is constructed on a watershed having significant runoff, and where the utility does not own the pond and the total water rights on the watershed. In this case, the pond is legally considered to be external to the plant, and control of the thermal discharge is subject to state and federal regulations. Plant No. 3713 in North Carolina is an example of this type.

Cooling ponds are normally formed by construction of a dam at a suitable location in a natural watershed. Soil under the pond must be relatively impervious to avoid excessive loss of water. Ponds may be constructed by excavation, but generally the cost would be much higher than for a dammed watershed. The size of the pond is primarily related to the plant generating capacity, and rough approximations of 4000-8000 sq m (1 to 2 acres) per Mw, are found in the literature. At 0.8 ha (2 acres) per Mw, the pond for a 1,000 Mw plant would be 800 ha (2,000 acres) in size. Thus, the pond size for such a plant would normally be large enough to serve as a recreational site in addition to its primary function.

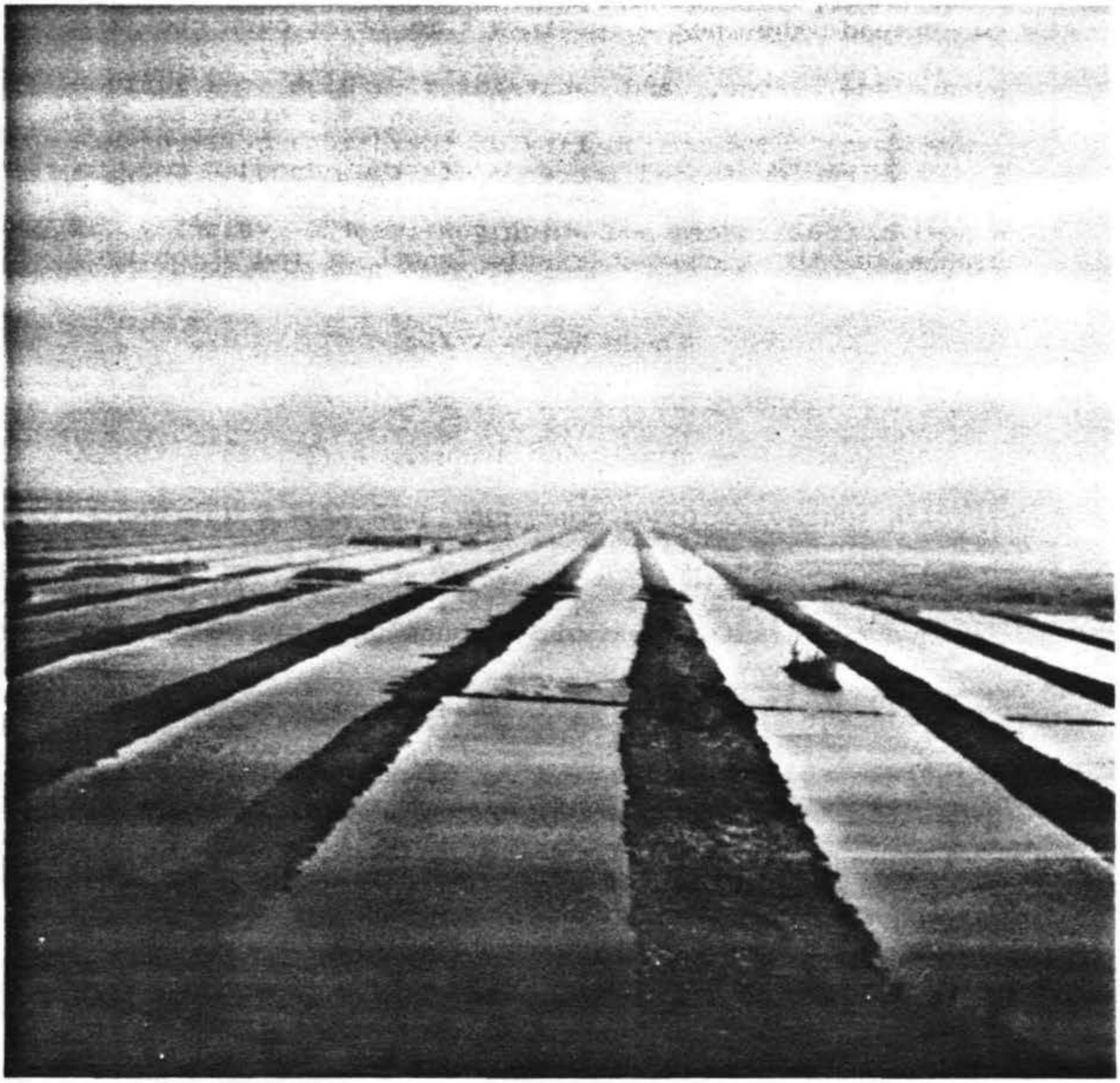
When a watershed is dammed to form a cooling pond, the shape is determined by the topography of the area. The station intake and discharge structures are placed on the cooling pond so that maximum use is derived from the pond, i.e. widely separated, if not at opposite ends of the pond. With excavated ponds, the shape is not totally limited by the topography. One station currently uses a pond with a dike separating the intake and outfall structures, and extending almost across the lake to provide a U-shaped pond. Another station, plant No. 1209, utilizes a series of canals as a "cooling pond" as shown in Figure B-VII-22. The land is flat, and the dikes between the canals provide a convenient place to pile the material dredged from the canal.

Considerable research on thermal aspects of cooling ponds has been undertaken. Likewise some of the research on the discharge of condenser water into lakes and rivers may be applicable. References 32, 84, and 120 are part of a series of five reports dealing with cooling ponds, and a more comprehensive study is described in Reference 246.

The performance of a cooling pond is dependent to a large extent on its physical features, as indicated below.

1. Ponds have been arbitrarily categorized in a number of ways, such as shallow or deep, stratified or non-stratified, and plug flow or completely mixed ponds. In terms of the above, the ideal pond is a deep, stratified pond in which the hot water flows through the pond on the pond surface with no longitudinal mixing, and the cool water is removed from a deep portion of the lake.

2. The configuration of the discharge structure for discharging the hot water from the plant, particularly in the case of shallow ponds, greatly affects pond performance. The discharge structure should be designed



COOLING CANAL
PLANT NO. 1209

Figure B-VII-22

to spread the hot water in a thin layer over the lake surface thus preventing mixing with the cooler subsurface water, and sustaining a high pond surface temperature to promote rapid heat transfer to the atmosphere. The suitability of the discharge structure is sometimes evaluated in terms of the Froude No., a ratio of the fluid momentum forces to the fluid gravitational forces and which relates the velocity of discharge to a characteristic length of the structure, normally the width of the channel.

$$\text{Froude No.} = V^2/Lg$$

where V = Velocity of discharge, m/s (ft/sec)

L = Width of discharge channel, m (ft)

g = Gravitational constant, 9.82 m/sec^2 (32.2 ft/sec^2)

Discharge structures are generally considered adequate for use in relation to cooling ponds when the Froude No. is less than 1.0.

3. The intake structure is normally located well beneath the pond surface, if not at the bottom. Its position in relation to the discharge structure is important. Currents within the pond, particularly wind currents, must be considered in placing the structure to get the best performance out of the pond.

4. The pond shape has some effect on performance. The extent of the effect is dependent on the degree to which density currents exist within the pond. For those ponds with strong density currents, the pond shape is usually insignificant.

5. The temperature of the discharge into the pond sets the driving forces for loss of heat to the atmosphere. Other important considerations include climatic factors, particularly wind speed, gross solar radiation, dewpoint temperature, and other factors which affect the equilibrium temperature of the pond. The pond size required for a particular plant depends on the climatic conditions in the immediate vicinity of the pond. Pond design is usually based on conditions which approach the most unfavorable conditions expected. The more accurate, reliable, and extensive the available data is, the more confidence can be placed in a design based on these data. The importance of the climatic factors

outlined above is demonstrated in the following equations which describe the relationships among the principal factors involved in sizing a cooling pond. At steady state conditions, the net heat loss from the pond is equal to the waste heat from the powerplant. The steady net heat loss from the lake surface is normally expressed as:

$$\text{Heat loss} = KA\ (T_s - T_E)$$

where K = Heat Exchange Coefficient, J/sq m-day-°C (Btu/sq ft-day-°F)

A = Area of Lake, sq m (sq ft)

T_s = Average Surface Temperature, °C (°F)

T_E = Equilibrium Temperature, °C (°F)

The equilibrium temperature (T_E) can be estimated by the following equation:

$$T_E = T_d + H_s/K$$

where T_d = Dewpoint Temperature, °C (°F)

H_s = Gross Solar Radiation, J/sq m-day (Btu/sq ft-day)

K = Heat Exchange Coefficient, J/sq m-day-°C (Btu/sq ft-day-°F)

The heat exchange coefficient (K) is closely related to windspeed as shown in Figure B-VII-23, which permits determination cf K in terms of windspeed and the temperature $T = \frac{T_d + T_s}{2}$ where an initiate value of T_s must be assumed.

The estimation of the average pond surface temperature is an important part of the analysis. Parameters necessary for this determination are the expected temperature rise and circulating water flow rate. The degree of mixing in the pond must be estimated. Where there is little mixing (slug flow), the temperature decrease occurs during the entire transit of the pond by a typical slug of circulating water. The other extreme is where complete mixing occurs, and the temperature throughout the pond is the same. The actual degree of mixing in any particular case would lie between these two extremes.

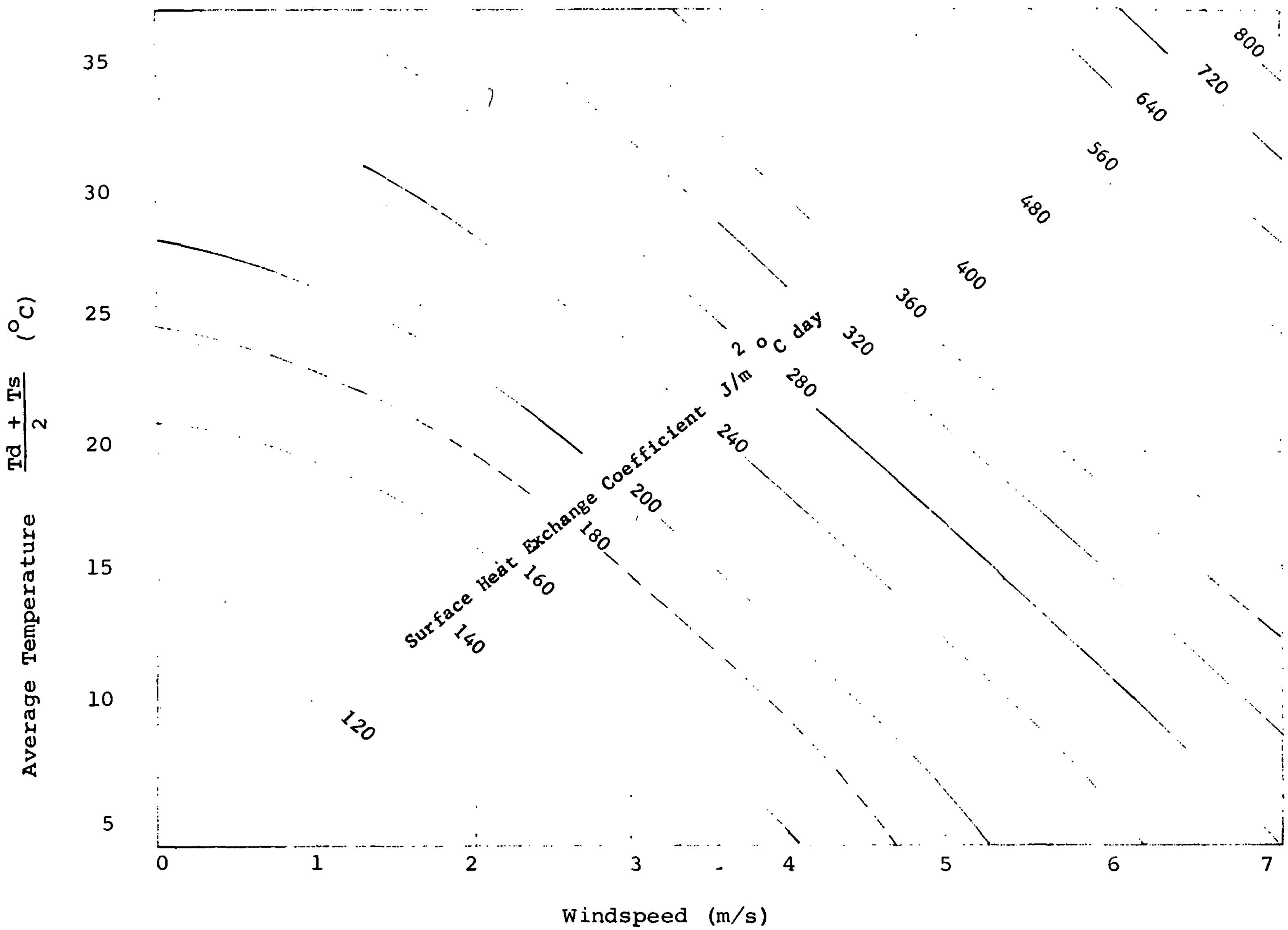


CHART FOR ESTIMATING COOLING POND SURFACE HEAT EXCHANGE COEFFICIENT
(From Reference 32)
FIGURE B-VII-23

The first step in the procedure for estimating the average pond surface temperature is to determine the discharge temperature to the cooling pond. This is done by first determining the quantity:

$$\frac{KA}{pc_pQ_p}$$

where K = Heat exchange coefficient estimated from Figure B-VII-23, J/sq m-day-°C (Btu/sq ft-day-°F)

A = Assumed pond area, sq m (sq ft)

p = Density water, kg/cu m (lb/ft^3)

c_p = Heat capacity, J/kg-°C (Btu/lb-°F)

Q_p = Condenser flow, cu m/day (ft^3/day)

Figure B-VII-24 can be used to determine the approximate area A. With the condenser rise, from Figure B-VII-25, θ (excess of discharge temperature, T_p, over the equilibrium temperature, TE) is determined. Note that curves for slug flow and complete mixing are given. Then the discharge temperature, T_p, and the inlet temperature, T_c, can be determined.

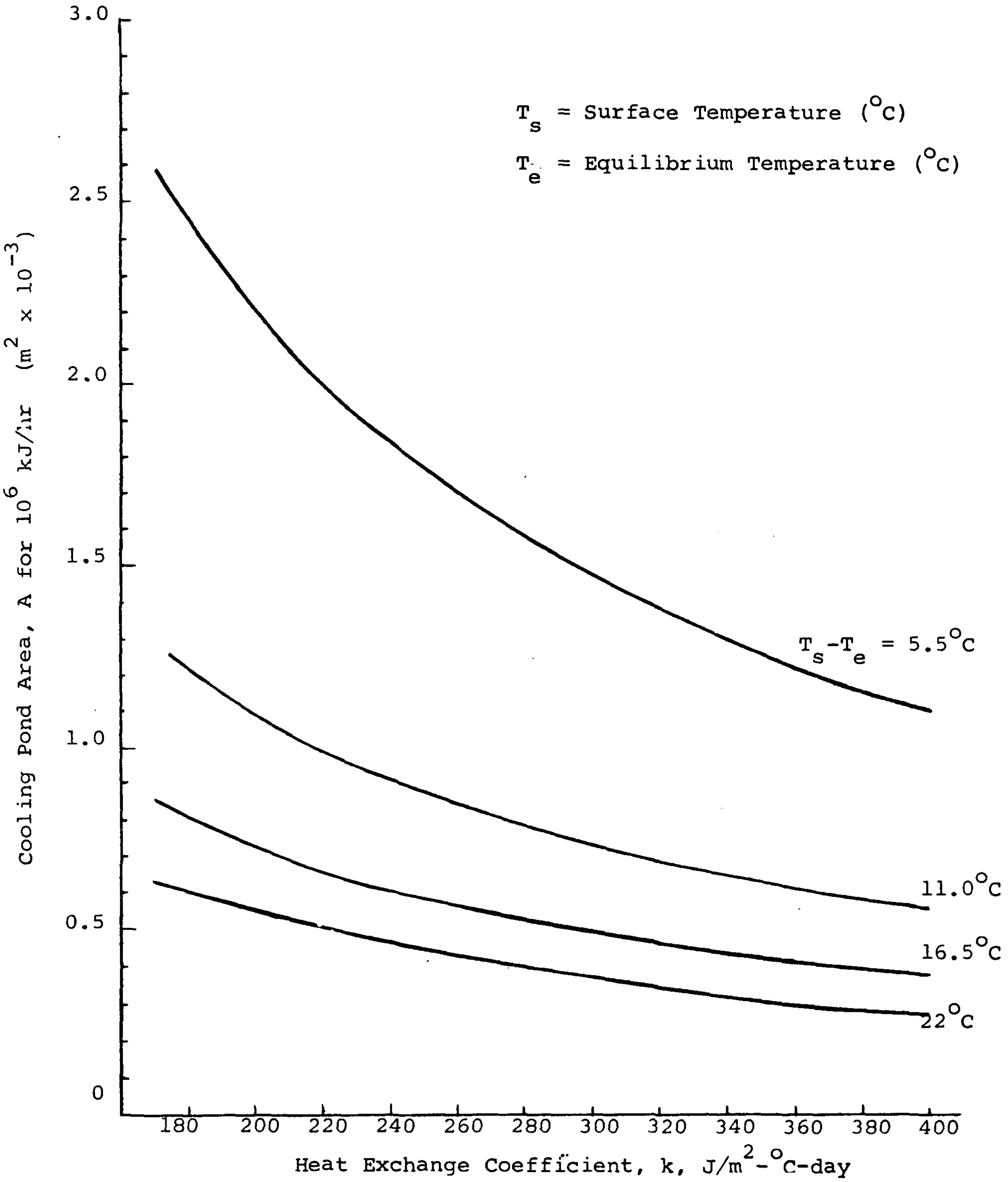
$T_p = T_E + \theta r$

$T_c = T_p$ - Condenser rise

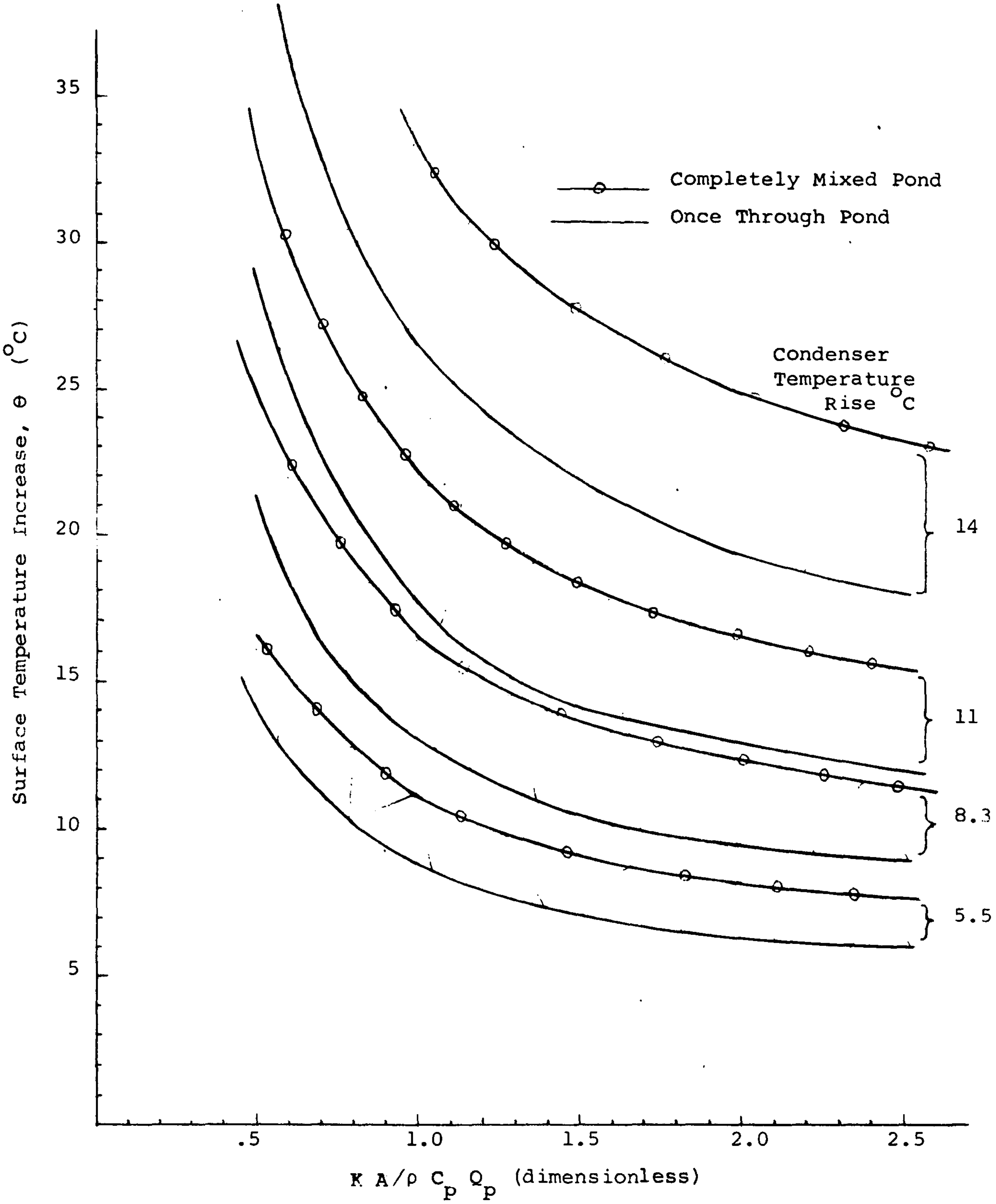
From Figure B-VII-26, using θ and KA/pc_pQ_p, θ average is determined, since θ is $T_s - T_E$, T_s is determined. This value of T_s will normally not correspond to the assumed value used to determine K. The correct value is then determined by iteration, i.e., new values for T_s are assumed and the process repeated until the two values of T_s agree to the degree of accuracy desired.

Once T_s has been estimated, the pond area can be determined from Figure B-VII-24, which determines the area required for each million kJ (million Btu) of heat to be rejected. If the cost per acre of pond surface is known, the cost per million kJ (million Btu) of heat rejected can be determined from Figure B-VII-27.

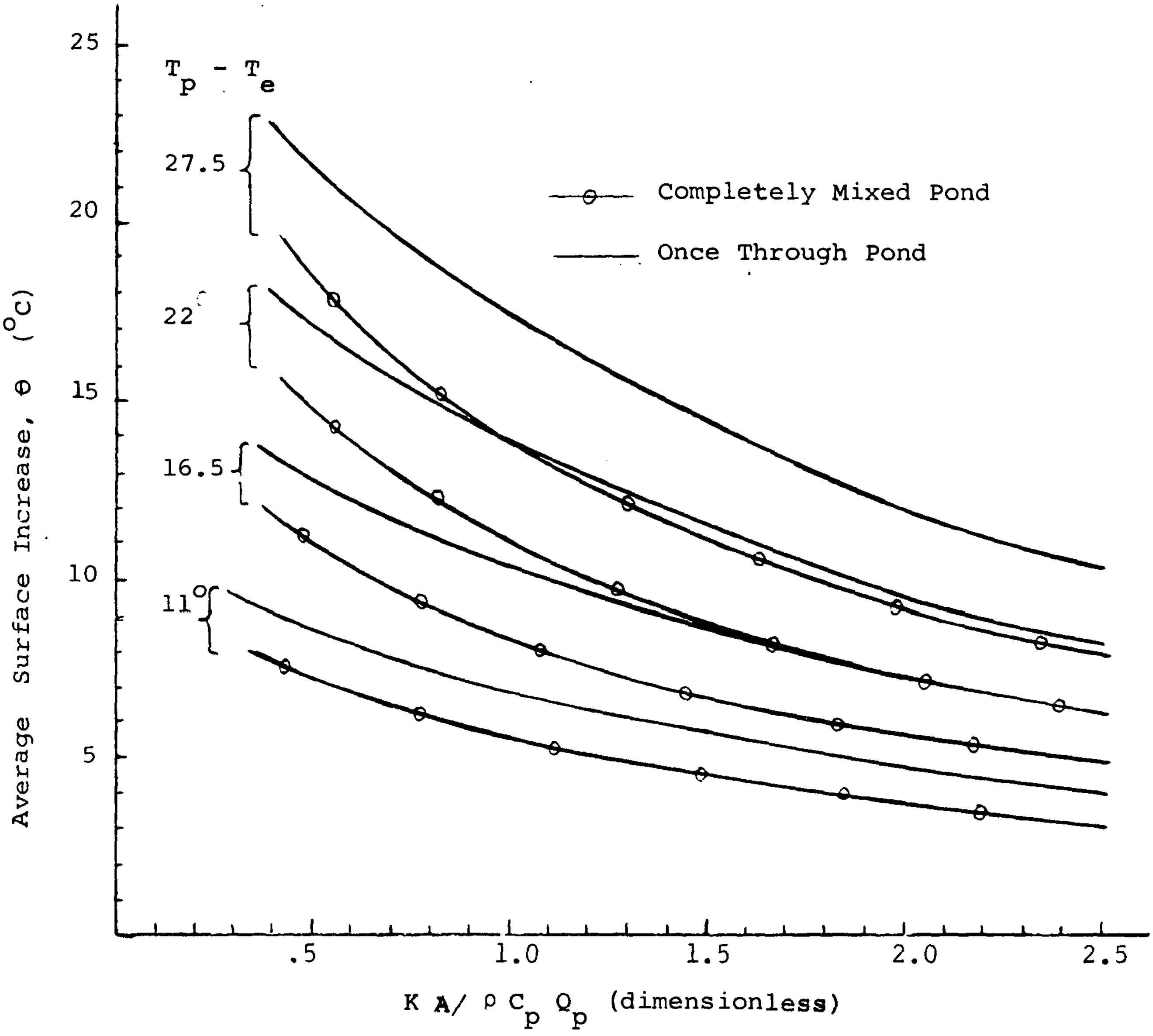
Costs for cooling ponds are very dependent on local terrain. In general, costs would include the following:



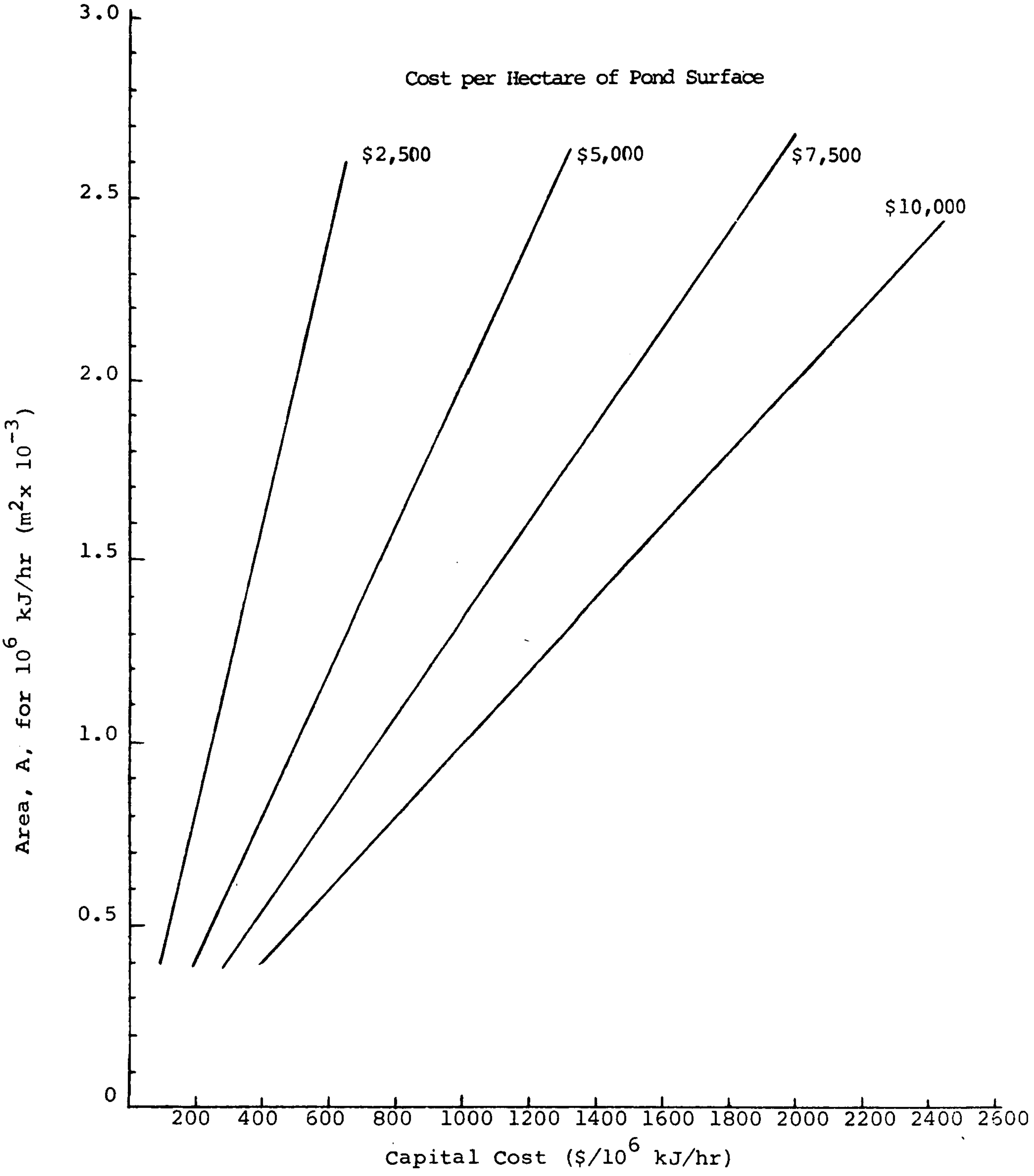
COOLING POND SURFACE AREA VERSUS HEAT EXCHANGE COEFFICIENT
FIGURE B-VII-24



DETERMINATION OF SURFACE TEMPERATURE INCREASE, θ, RESULTING FROM THERMAL DISCHARGE OF STATION
FIGURE B-VII-25



DETERMINATION OF AVERAGE SURFACE TEMPERATURE INCREASE, θ, RESULTING FROM THERMAL DISCHARGE OF STATION
FIGURE B-VII-26



ESTIMATION OF CAPITAL COST OF COOLING POND

FIGURE B-VII-27

I. Preliminary
    1. Soil surveys
    2. Topographical mapping

II. Construction
    1. Dam or basin
    2. Discharge structure
    3. Intake structure
    4. Canals or pipelines associated with 2 and 3
    5. Makeup water system (pipelines, canals, pumps, etc.), if required.
    6. Auxiliary equipment for above, roads, fencing, etc.

III. Maintenance
    1. Canal, pipeline maintenance
    2. Intake and discharge structures

Spray Ponds

The total use of spray cooling in power generation in not easily compiled. Ceramic Cooling Tower Company reports 645 modules in operation, shipped or in manufacture. Richards of Rockford Inc., has 365 units in similar stages for large and small applications. Cherne Industrial reports small volume sales to three customers, primarily for testing. Ashbrook Corporation has supplied 14 units to ten customers.[405]

Spray systems can be utilized to reduce the large area required by cooling ponds by up to a factor of ten. Two types of spray systems are available. In a fixed system, which essentially operates in a once-through mode, the hot water is pumped through a grid of piping, into which nozzles have been placed at regular intervals. The water is sprayed out, and cools by evaporation and sensible heat transfer to the air as it falls to the pond below. Water from the pond is pumped directly to the condenser. To obtain adequate cooling on this once-through basis, the spray must be fine. This factor, coupled with wind factors, can lead to large drift losses and associated problems in the vicinity of the pond. The relatively high pumping losses and lengthy piping required for such a fixed system would make this type of design relatively costly for a medium-sized power station.

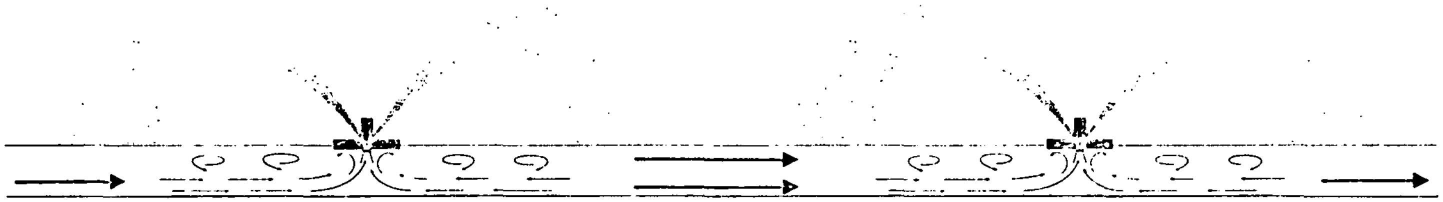
The second type of spray pond is commonly called a spray canal due to its flow-through hydraulics and shape which makes full use of prevailing winds to enhance cooling performance. The spray is produced by modules moored at intervals in the canal and floating on the water surface. Two types currently in use are illustrated in Figures B-VII-28 and B-VII-29. The module in Figure B-VII-28 is a unitized pump and spray module. The module in Figure B-VII-29 has a central pump supplying four nozzles. Both units are powered by 56,000 watt (75 hp) motors and spray 0.631 cu m/sec to 0.789 cu m/sec (10,000 to 12,500 gpm). Two characteristics of this system are important. The first is that each slug of water can be sprayed in repetitive steps, thus minimizing the need for small droplets required by the fixed system. The droplet size can be larger, reducing the drift problem. Secondly, not all the water need be sprayed, but enough to provide the required cooling. This permits adjustment of the number of modules operating to the climatic conditions and generating level of the plant.

The use of these modules in the utility industry is relatively new, although tests have been underway for some years. Plant No. 3304 and Plant No. 5105 are using, or are installing powered spray modules. The largest installation in use is at Plant No. 0610. The canal of plant no. 0610 is U-shaped as shown in Figure B-VII-30. The intake and discharge structures are at the same end of the pond. The power and control systems for the modules are located on the central dike. Figure B-VII-31 shows the modules in operation. The diameter of the spray pattern is about 15 meters (50 feet).

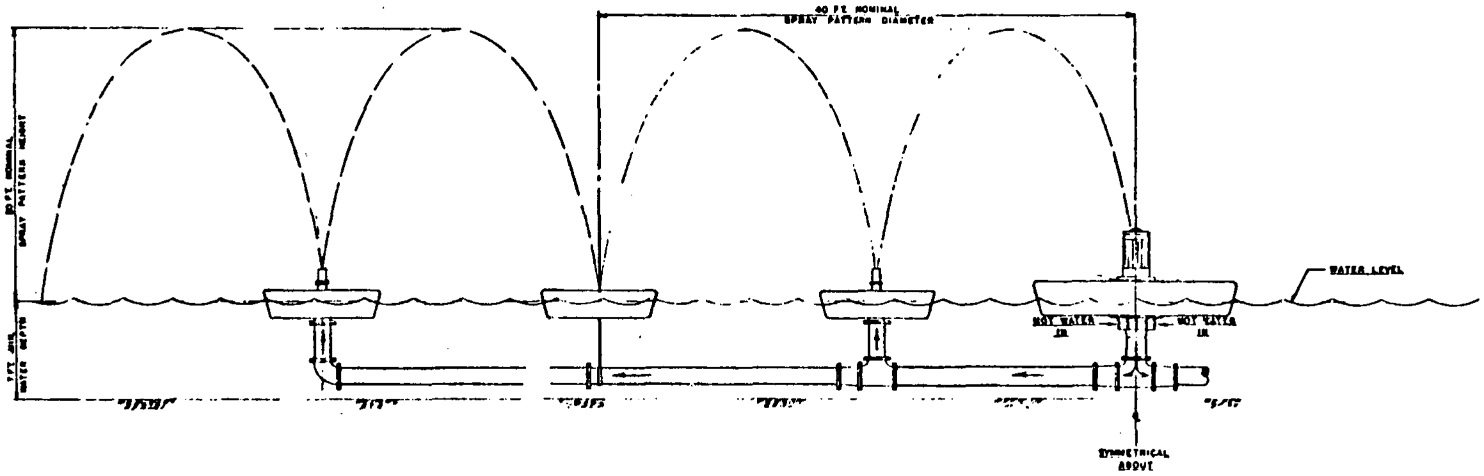
Plant No. 1723 is installing a large number of each design. Spray modules are being used primarily for helper systems on existing plants when additional units are added to a plant.

The design of the cooling canal is more complex than that of a cooling tower, and computer programs are often used. To make the best use of climatic conditions, these systems are designed as canals where all the modules are exposed insofar as possible to the ambient air conditions, reducing adverse interference of performance due to proximity to other modules. The canals can be circular in shape, or straight, as required. The canals should be aligned perpendicular to the prevailing winds for maximum ambient air exposure, and therefore maximum module efficiency.

Design of the system involves determining the incremental contribution to cooling of each set of modules in series. The first module's inlet temperature is the condenser discharge temperature. The cooled spray from the first module remixes with the water in the canal, and the resulting temperature of the canal is the temperature at the inlet to the second set of modules. This procedure is continued until the desired temperature is reached, or the increase in over-



UNITIZED SPRAY MODULE
(From Reference 365)
FIGURE B-VII-28

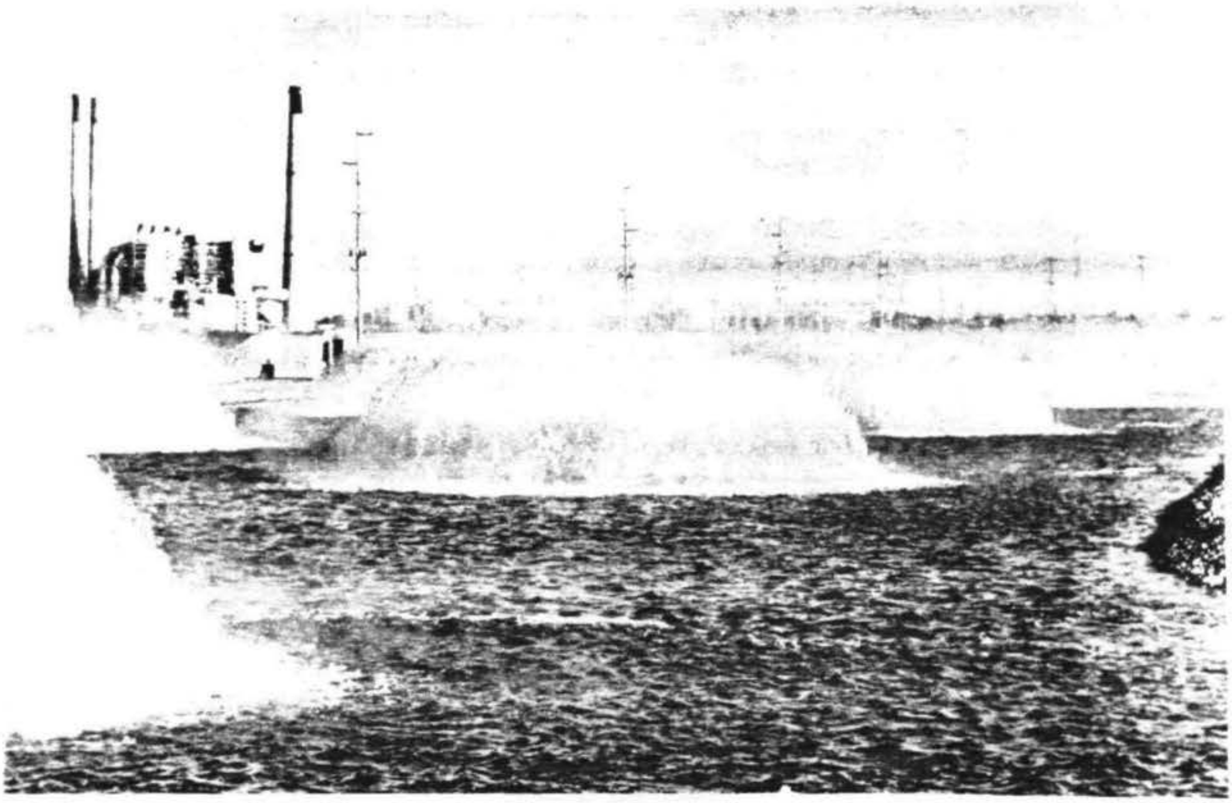


FOUR SPRAY MODULE
(From Reference 366)
FIGURE B-VII-29

SPRAY CANAL

PLANT NO. 0610

Figure B-VII-30



SPRAY MODULES

PLANT NO. 0610

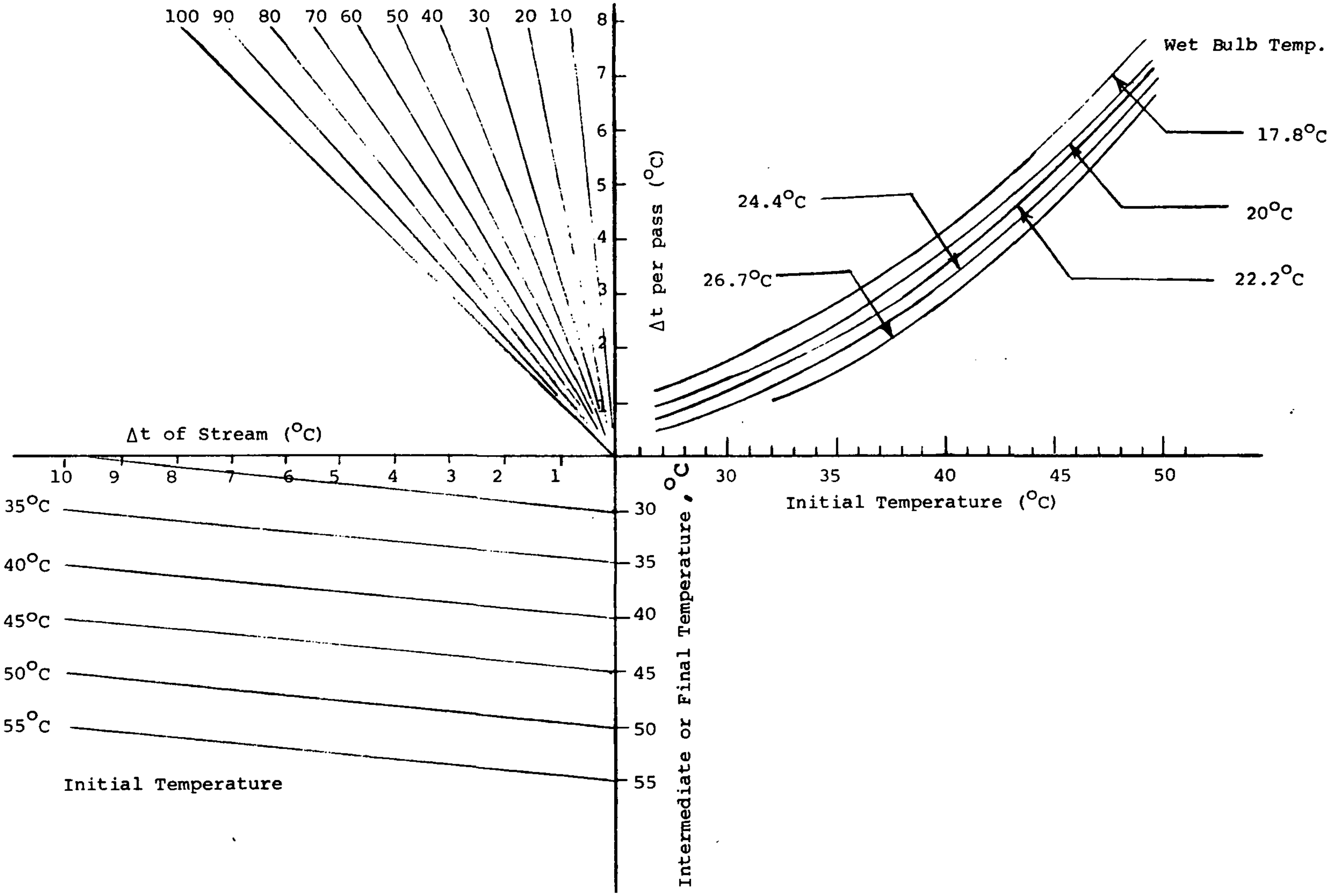
Figure B-VII-31

all performance with additional modules is not cost effective. Using some general data on one manufacturer's units, Figure B-VII-32 was developed to give a pictorial representation of the process. The initial temperature is the inlet temperature to the first set of modules (condenser discharge temperature). The wet bulb temperature is then used to determine the expected temperature decrease of the sprayed water. From the percentage of water sprayed, the change in canal temperature can be determined, and this translated into a new exit temperature from the modules. This then becomes the initial temperature for the second set of modules. The number of modules in parallel at any point in the canal can also be optimized.

The retrofit installation at plant no. 1723 is representative. The two generating units at the plant are rated at 809 Mw each. The cooling canal will encircle the plant and will be 4.1 km (2.5 miles) long. The canal will contain 176 units from one manufacturer, and 152 units from another manufacturer. The number of modules, or blocks of them operating at any one time will be adjusted to give the amount of cooling required. The installed power for the 328 units is 18,300 kw (24,600 hp). At 90% efficiency, this amounts to 20.4 megawatts, or 1.26% of the plant's previous output using once-through cooling. Since higher cooling water temperatures are expected, thereby reducing the plants gross generating capacity, the combined reduction in plant generating capacity will be greater than 1.26%.

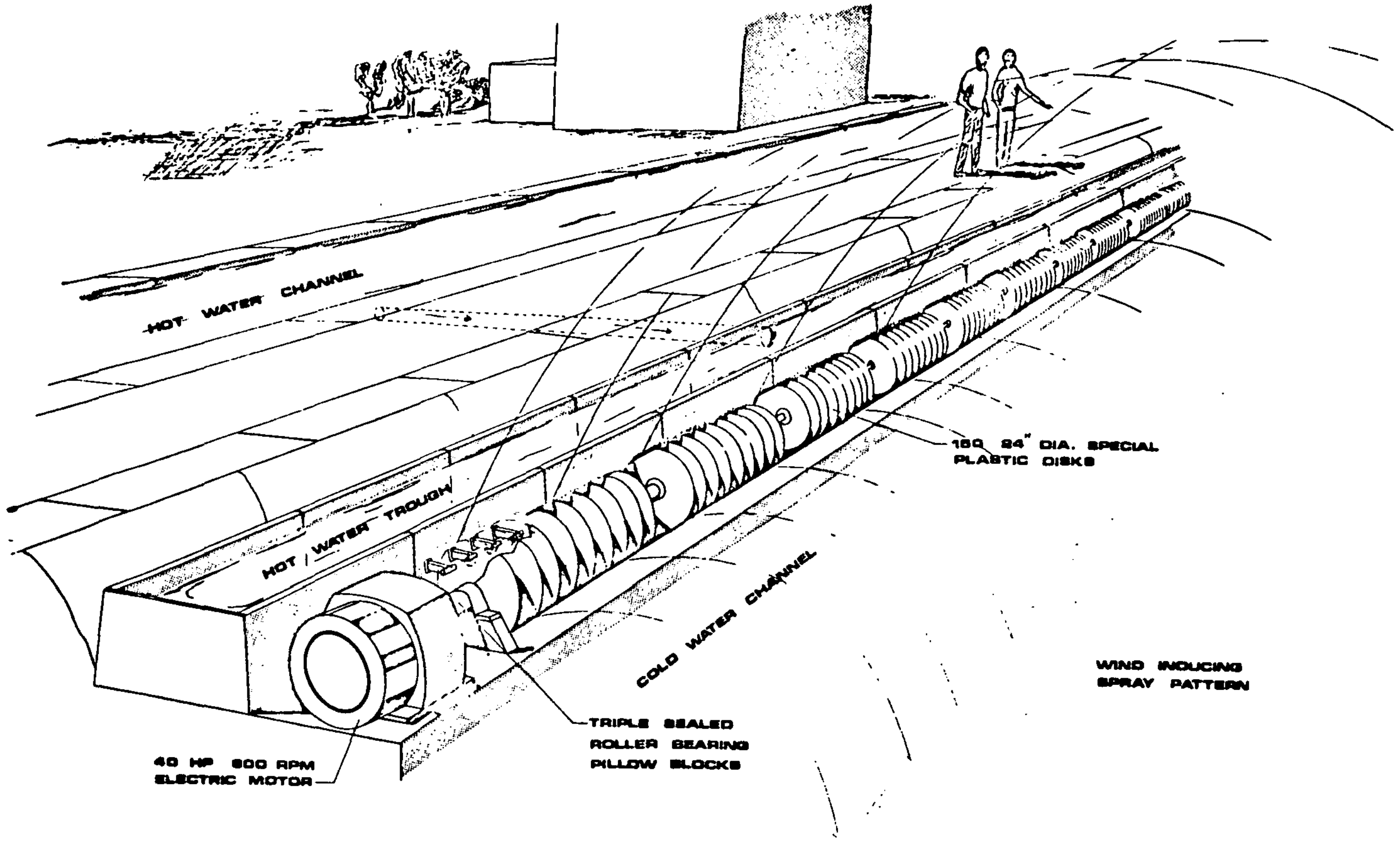
For the past several years, another manufacturer has been testing a rotating disc design for producing sprays. Their current design is shown in Figure B-VII-33. This design is currently undergoing field evaluation at a station in the United States. A cross section of a proposed installation is shown in Figure B-VII-34. The spray droplets produced by these rotating discs are about 1 mm in size. As with the fixed spray systems, this size is required to get adequate cooling performance. With this size drop, drift is a problem, and adequate provision to minimize drift losses must be made.

Insufficient data has been published to make reliable performance or cost estimates. From some of the limited performance data the curves in Figures B-VII-35 and B-VII-36 were developed.

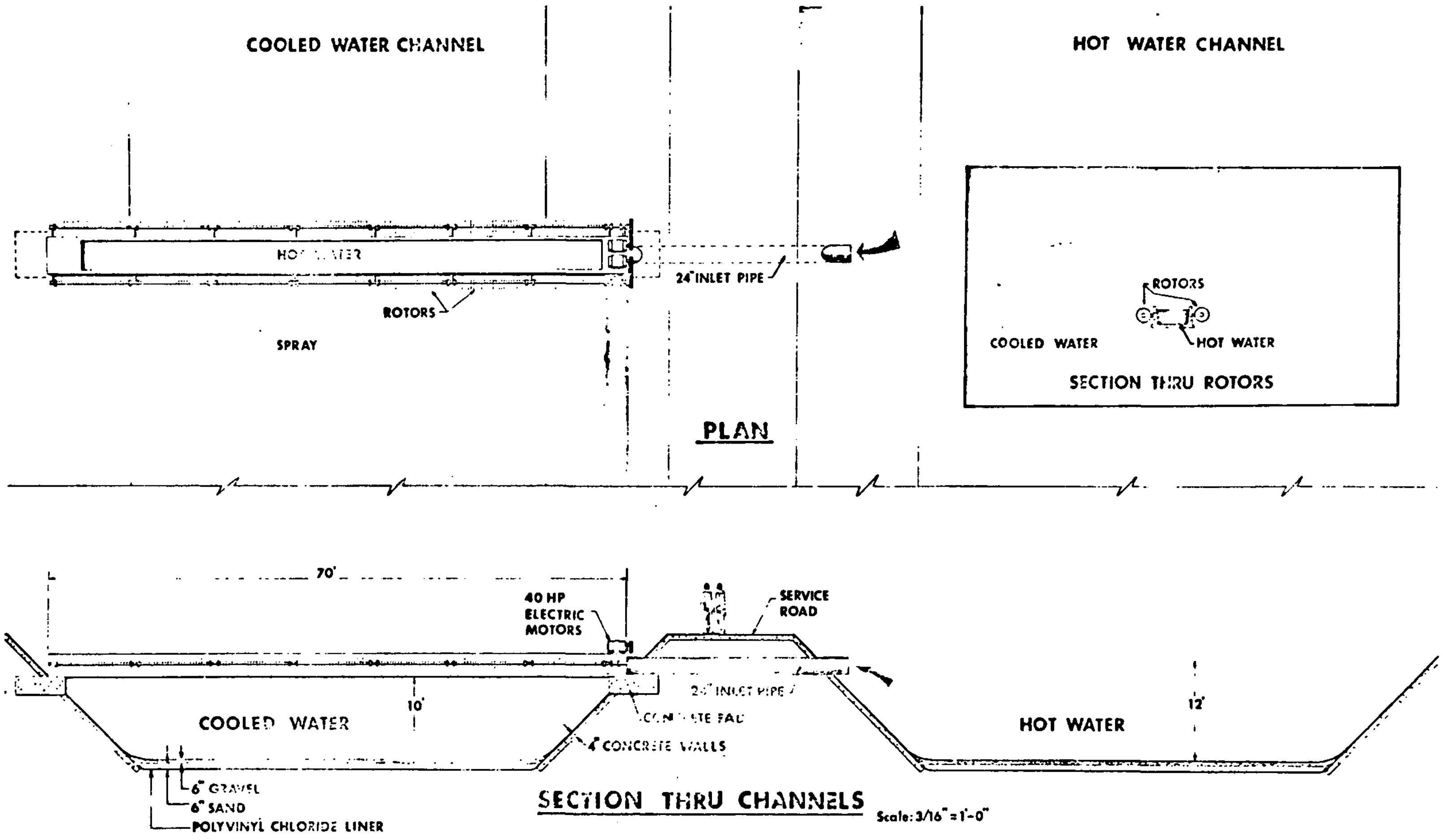


GRAPHIC REPRESENTATION OF DESIGN OF SPRAY AUGMENTED COOLING POND

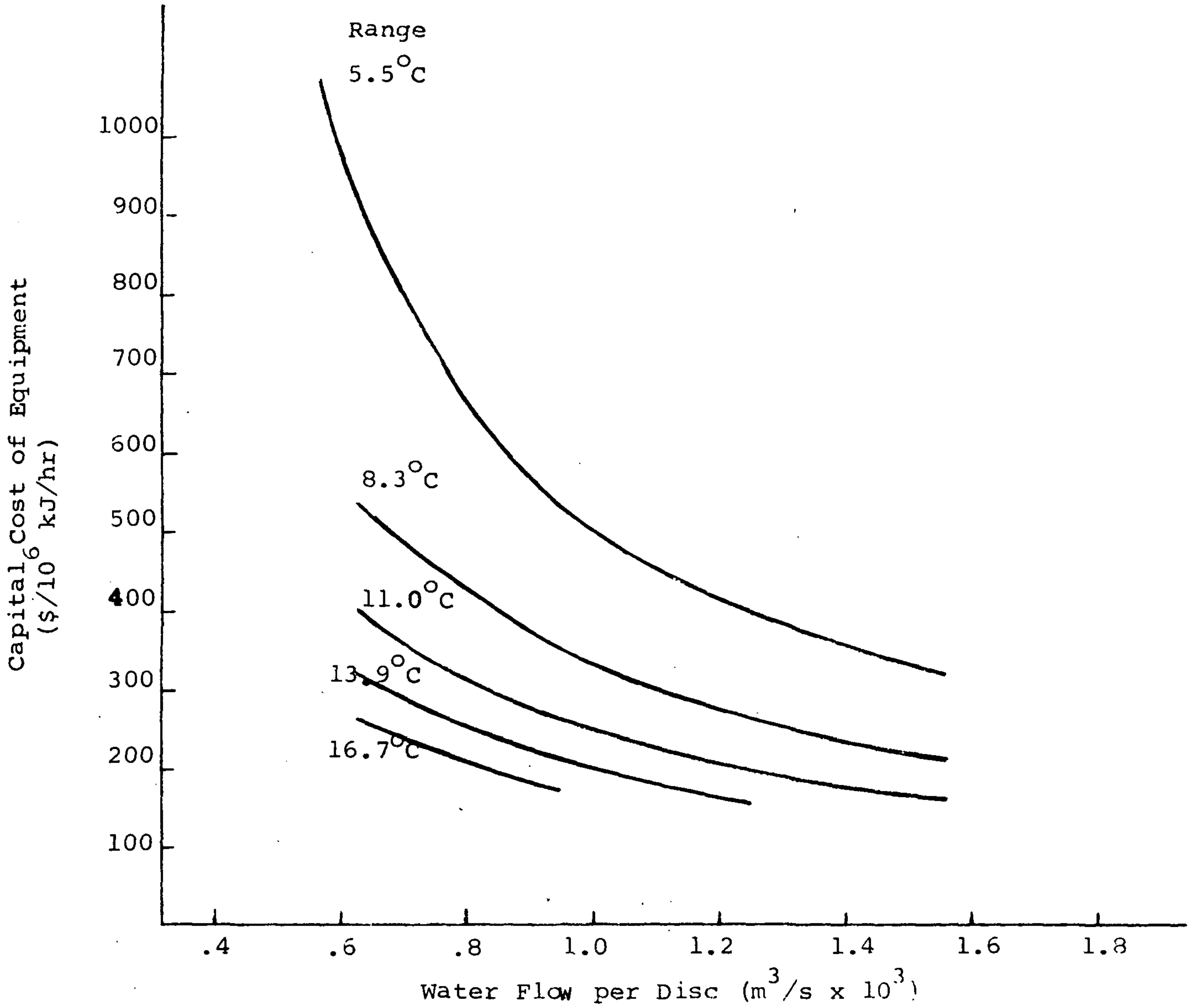
Figure B-VII-32



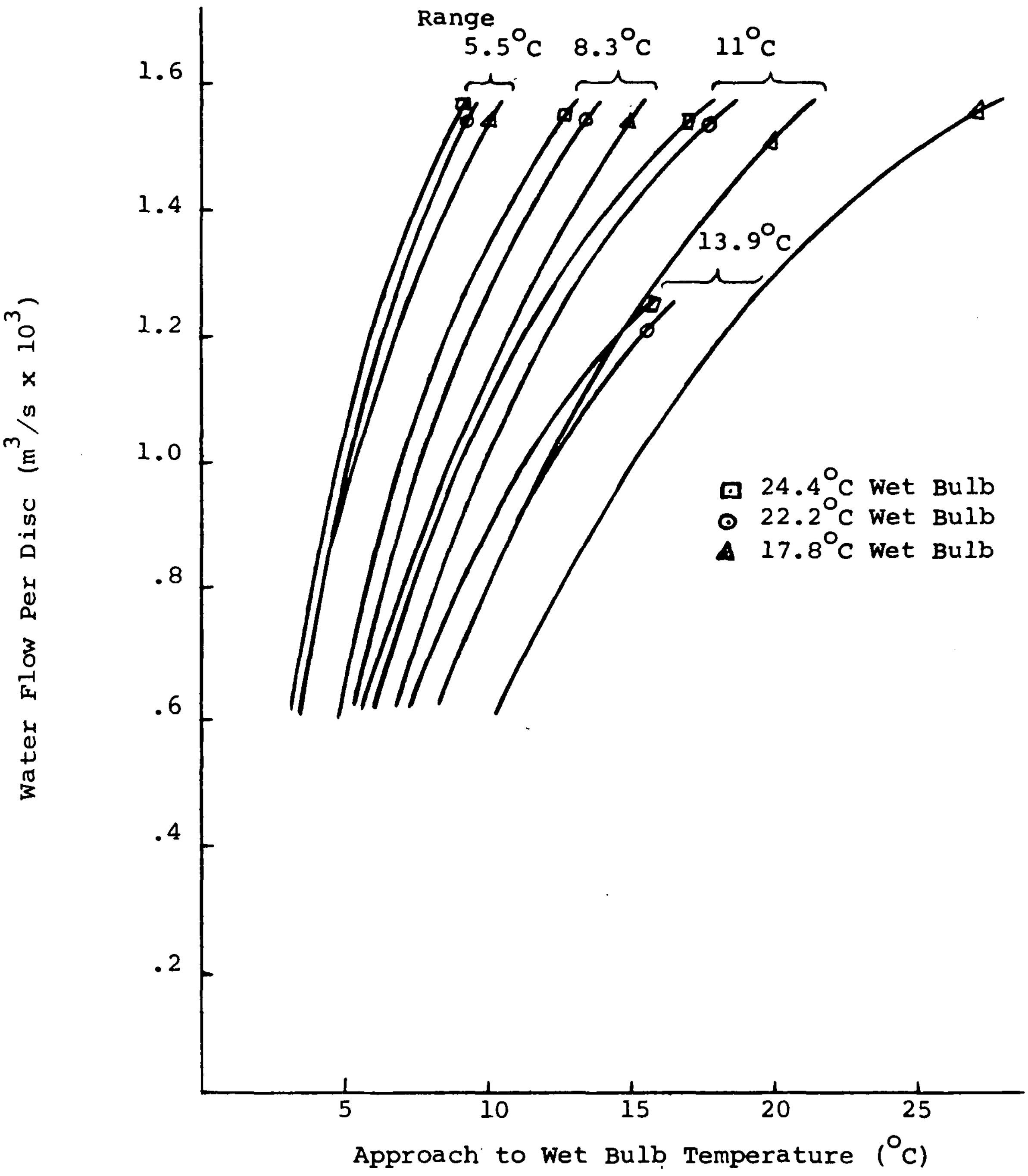
THERMAL ROTOR SYSTEM
FIGURE B-VII-33
(From Reference 389)



DOUBLE SPRAY FIXED THERMAL ROTOR
(From Reference 360)
FIGURE B-VII-34



GRAPHIC REPRESENTATION OF PRELIMINARY COST DATA
ON ROTATING DISC DEVICE
FIGURE B-VII-35



DETERMINATION OF REQUIRED FLOW PER DISC
FOR ROTATING DISC DEVICE
FIGURE B-VII-36

Wet Type Cooling Towers

A number of different types of evaporative cooling towers have been, and are currently, in use. The basic types are as follows:

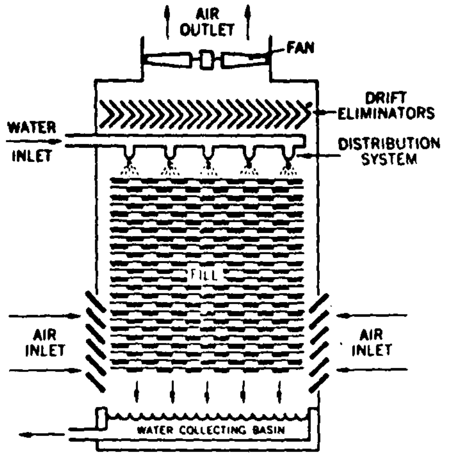
Mechanical Draft:	Natural Draft (Hyperbolic):	Dry Type:
Counterflow-Induced Draft	Counterflow	Direct
Crossflow-Induced Draft	Crossflow	Indirect
Counterflow-Forced Draft	Counterflow-Fan Assisted	
Crossflow-Forced Draft		
Wet-Dry--Any of the above		

The terms crossflow and counterflow refer to the relationship between the air flow and the water flow. In counterflow, the water flows downward through the packing and the air flows upward (Figure B-VII-37). In crossflow, the water still flows downward, but the air flows horizontally (or perpendicularly to the water) from outside to inside as shown in Figure B-VII-38. Induced draft refers to the means for developing the air flow by a fan mounted on top of the tower which pulls the air through the tower (Figures B-VII-37 and B-VII-38). In the older, and little used today, forced draft system fans are mounted around the periphery of the tower at ground level and force the air upward through the tower.

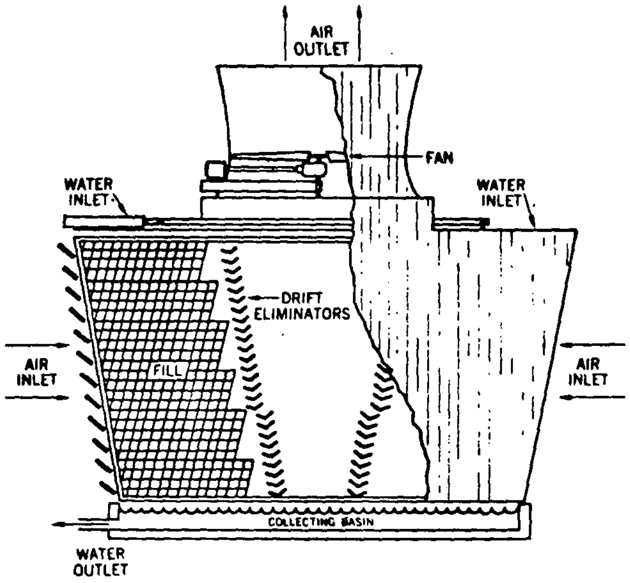
Drift eliminators, common to all towers except the dry-type, are used to remove most of the entrained water droplets from the air stream prior to its leaving the tower.

The wet-dry tower is a relatively new development. It consists of an upper section of dry tower emitting warm air heated solely by conduction, and a lower wet section emitting the nearly saturated air which has a high fogging potential. These two air streams are mixed in the tower, significantly reducing the fogging potential.

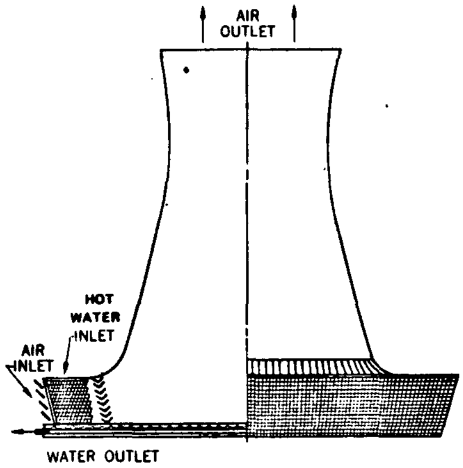
Natural draft towers are commonly known as hyperbolic towers, since the chimneys are hyperbolic in shape to take advantage of the excellent stress characteristics of this shape. The chimneys are normally constructed of reinforced concrete. A crossflow tower is shown in Figure B-VII-39. The tower shown in Figure B-VII-40, takes up less land space than the crossflow tower. The chimneys on these towers are tall, ranging from 90 to over 150 m (300 to over 500 feet). The tower height has the advantage that the plume is emitted high enough above the ground that if fog develops, it will normally not create a ground level hazard.



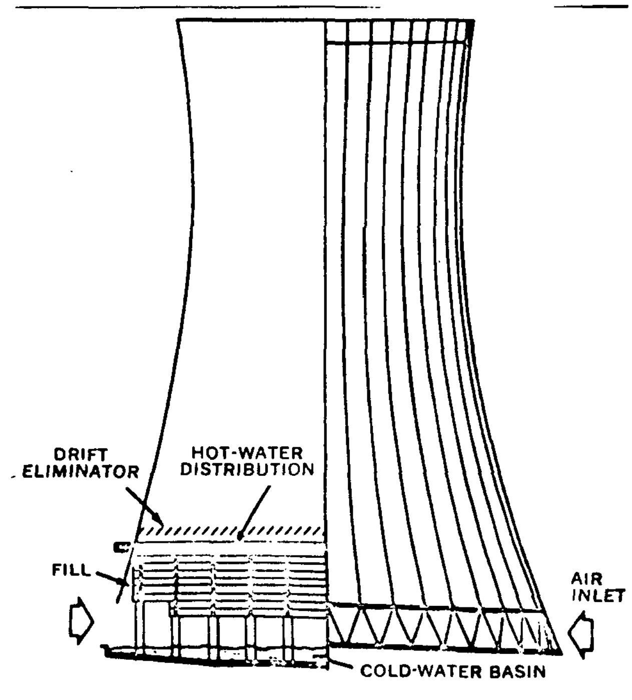
COUNTERFLOW MECHANICAL DRAFT TOWER
FIGURE B-VII-37



CROSSFLOW MECHANICAL DRAFT TOWER
FIGURE B-VII-38



CROSSFLOW NATURAL DRAFT TOWER
FIGURE B-VII-39



COUNTERFLOW NATURAL-DRAFT COOLING TOWER
FIGURE B-VII-40

A recent modification to the natural draft tower is the fan-assisted hyperbolic. In this design, fans are placed at the periphery of the tower, along the bottom to force the air through the tower. The required tower height is diminished, since air flow does not depend solely on the difference in air density inside and outside the tower as in the unassisted tower. Several of these fan-assisted towers are in use in Europe, and have been proposed for use in specific cases in this country.

The dry-type cooling towers rely solely upon conductive and convective heat transfer for their cooling effect. Two types of systems are used. In the "direct" system, the steam condenses directly in the tubes of the heat exchanger in the tower. This type is restricted to relatively small plants due to the size of the steam piping required to circulate the relatively low density steam. In the "indirect" sytem, cold water from the tower is used to condense the steam from the turbine and the warmed water is circulated through the tower. Since the system is completely closed, a direct contact condenser can be used, greatly reducing the condenser terminal temperature difference (TTD). With the direct contact condenser, the circulating water must be of the same quality as the boiler makeup water, however direct contact condensers are less expensive than shell and tube condensers. The air system for the tower may be either induced, forced, or natural draft.

Wet Mechanical Draft Towers

The wet tower cools the water by bringing it into contact with unsaturated air and allowing evaporation to occur. Heat is removed from the water as latent heat required to evaporate part of the water. Approximately 75% of the total heat transferred is by evaporation, the remainder by sensible heat transfer to the air.

In addition to the thermodynamic potentials, several other factors influence the actual rate of heat transfer, and ultimately, the temperatrue range of the tower. A large water surface area promotes evaporation, and sensible heat transfer rates are proportional to the water surface area provided. Packing (an internal lattice work) is often used to produce small droplets of water and thus increasing the total surface area per unit of throughput. For a given water flow, increasing the air flow increases the amount of heat removed by maintaining higher thermodynamic potentials. The packing height in the tower should be high enough so that the air leaving the tower is close to saturation.

The mechanical draft tower consists of the following essential functional components:

1. Inlet (hot) water distribution
2. Packing (film)
3. Air moving fans
4. Inlet-air louvers
5. Drift or carry over eliminators
6. Cooled water storage basin

Although the principal construction material in mechanical draft towers is wood, other materials are used extensively. In the interest of long life and minimum maintance, wood is generally pressure treated with a water-borne preservative. Although the tower structure is still generally treated redwood, a reasonable amount of treated fir has been used in this and other portions of the tower in recent years. Sheathing and louvers are generally of asbestos cement, and fan stacks of fiber glass. The trend in fill is to fire-resistant extruded PVC which, at little or no increase in cost, offers the advantage of unlimited life to its fire-resistant properties. Some asbestos cement is also used for fill. Even the trend in drift eliminators is away from wood to either PVC or asbestos cement.

Two problems arise from the use of wood: decay, and its susceptibility to fire. On multi-celled towers, the cost of fire prevention system can run into several hundred thousand dollars or more. Constant exposure to water results in leaching of the lignin from the wood, reducing its strength. Steel construction is occasionally used, but not extensively, if at all, for units in the powerplant industry.

Concrete construction, never popular because of relatively high labor costs, is actively being considered for large units of the type used in steam electric generating stations. The savings in fire protection costs and extended life make this alternative attractive in many cases.

Inlet water distribution systems are operated at low pressure and wood stave pipe, plastic and metallic pipe have been used. The blades on the fans must be reasonably lightweight, and corrosion resistant. Both cast aluminum and GRP (glass reinforced plastic), are generally used today. For large towers mounted on the ground, concrete cooled-water storage basins are used almost exclusively. For other applications, both wood and sheet metal basins have been used.

Reference 6 discusses the primary advantages and disadvantages of various types of wet mechanical draft cooling towers as described below.

Wet Mechanical Draft Tower - Induced Draft - Crossflow

Currently one of the most widely used wet mechanical draft towers in the larger sizes is the induced draft crossflow tower illustrated in Figure B-VII-38. Primary advantages for this tower are:

1. Lower pumping head as a result of lower packing.
2. Lower pressure drop through the packing.
3. Higher water loadings for a given height.
4. Lesser overall tower height.

Compared to the counterflow tower, crossflow towers have the following disadvantages:

1. A substantial correction factor must be applied to the driving force to take into account the reduced thermodynamic potentials in parts of the fill. This is particularly true at wide ranges and close approaches. More ground area and more fan horsepower may be required in some cases.
2. The packing is not as efficient, and more air flow is required for an equivalent capacity tower.

Despite these disadvantages, the crossflow tower is widely used. With proper louver design, ice buildup is minimal. The design is much more versatile, with a tower available to meet almost every need.

Sizing and costing of mechanical draft towers are dependent on climatic or operating conditions. Basic parameters controlling size and cost include:

1. Climatic conditions, particularly wet bulb temperatures

during the summer months.

2. Heat load from the powerplant.

3. Cooling water flow rate (or temperature range).

4. Approach temperature.

Two of the major cooling tower manufacturers use proprietary factors for estimating the cost of cooling towers. Wet bulb temperature, approach temperature and cooling tower range are used to determine the factor. Then, the factor and the circulating water flow are used to determine the tower cost. Tables illustrating use of the factor by one of the manufacturers are shown in Figure B-VII-41. The rating factor obtained from these curves is inserted into the following equation:

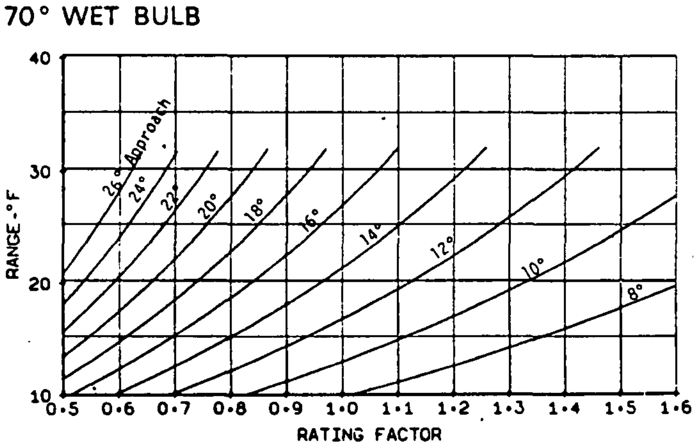
Tower Units = Rating Factor x Cooling Flow (gpm)

A set of simple calculations then provides Figure B-VII-42; where cost/10^6 Btu is shown as a function of Rating Factor and cooling tower range. The cost factor used was $8.11 for the cost of a tower unit.

The other manufacturer mentioned uses a slightly different technique. Using the cooling range, wet bulb temperature, and approach temperature, a "K" factor is determined. (Figure B-VII-43). The "K" factor is multiplied by the cooling water flow rate. Another chart gives a "C" factor, which multiplied by the flow through the tower gives an estimated capital cost. The graph for the "C" factor also has curves for determining fan horsepower and basin area. A comparison between the rating factor of Manufacturer A and the K-Factor of Manufacturer B is shown in Figure B-VII-44. The relationship between the two factors is essentially linear.

The curves in Figure B-VII-43 take into account a size factor, something that the other procedure omits. Some costs for various K-Factors and ranges are shown in Figure B-VII-45.

In addition to water lost by evaporation, a small percentage of the water is lost as drift, or small droplets carried out of the tower with the air flow. Drift eliminators are generally used in the tower to reduce this to a minimum. Current designs reduce these losses to a small percentage of the throughput. This drift contains salts and chemicals added to the water for treatment. These droplets fall out



TYPICAL CHART FOR DETERMINING RATING FACTOR

(From Reference 74)

Figure B-VII-41

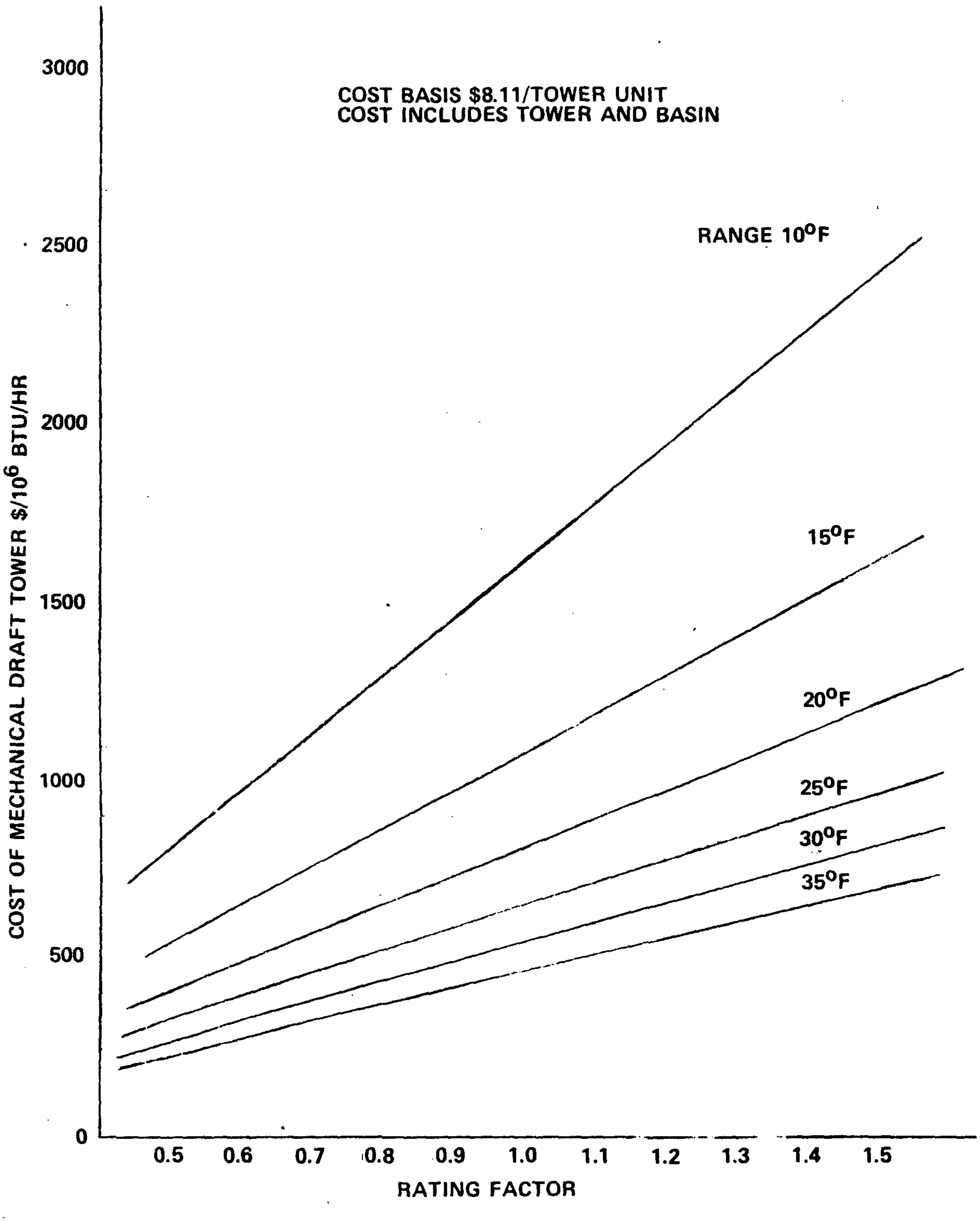
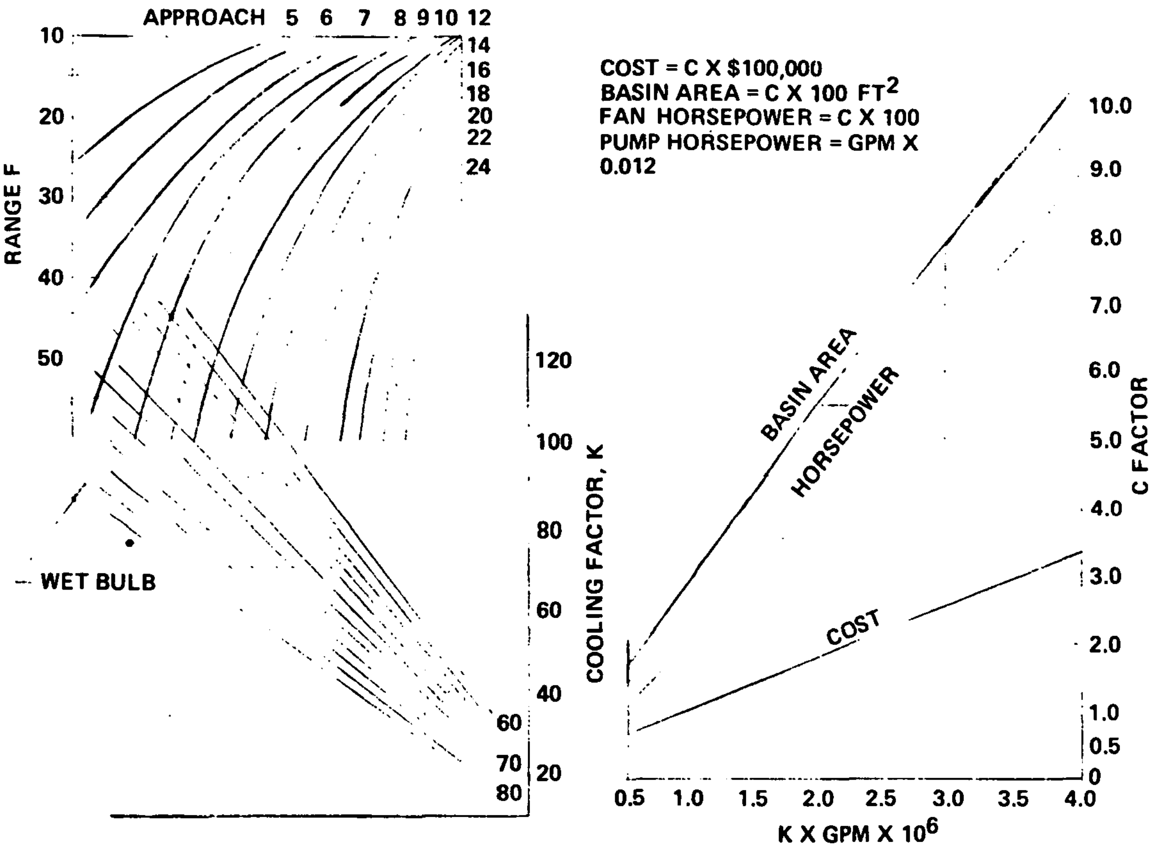
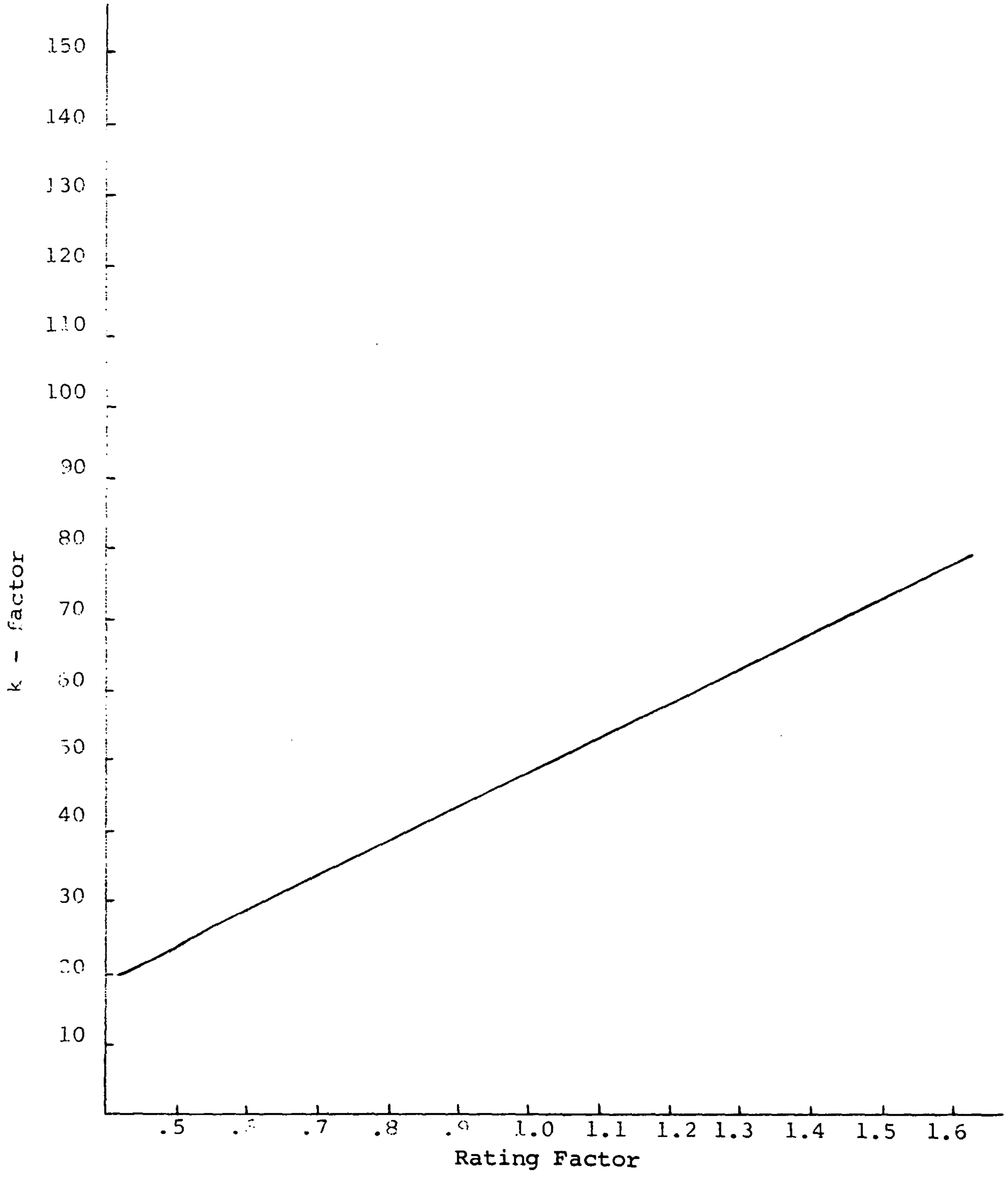


FIGURE B-VII-42 COST VS RATING FACTOR MECHANICAL DRAFT TOWER (FROM REFERENCE 74)

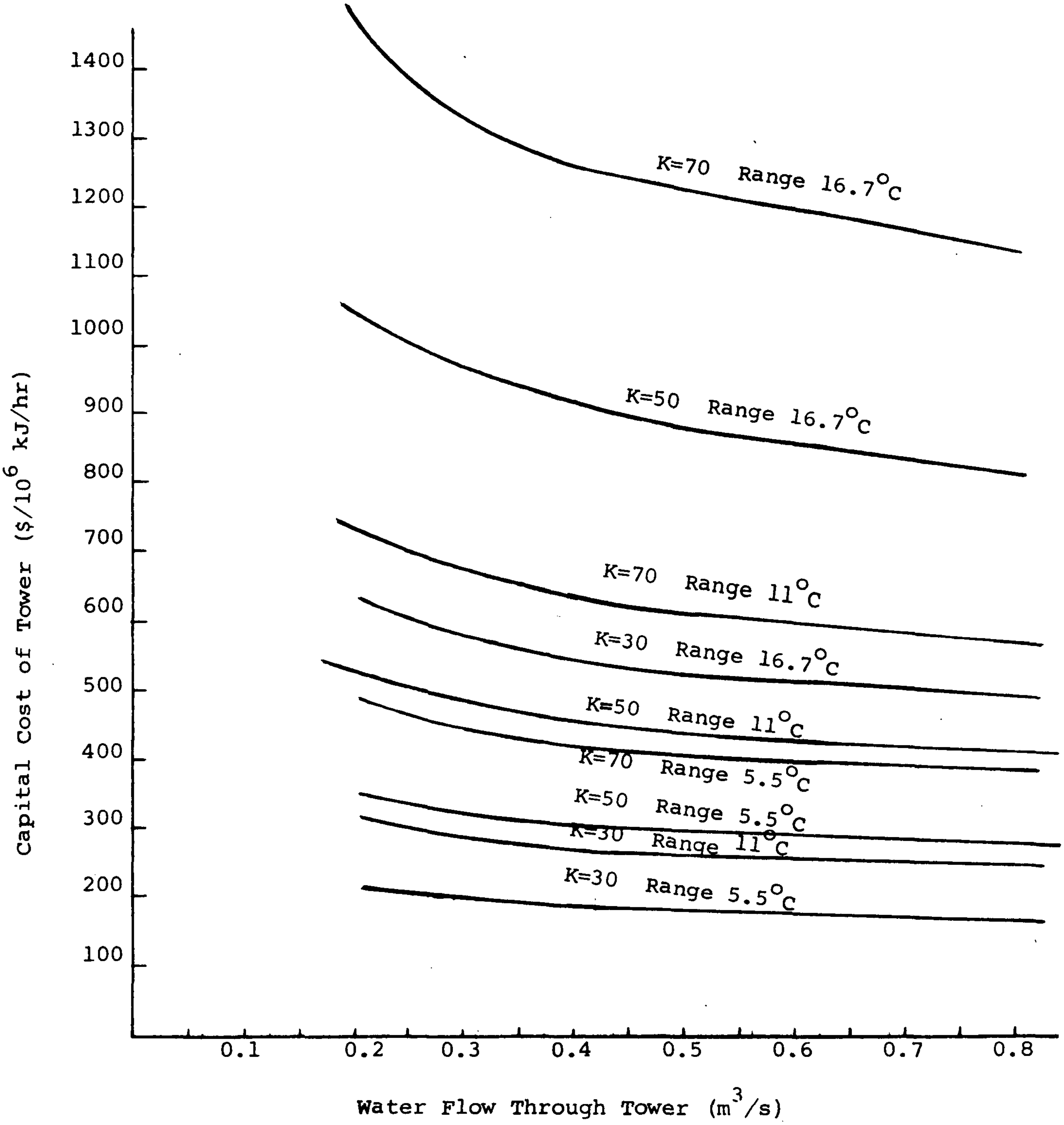


COST = C X $100,000
BASIN AREA = C X 100 FT^2
FAN HORSEPOWER = C X 100
PUMP HORSEPOWER = GPM X 0.012

FIGURE B-VII-43 COOLING TOWER PERFORMANCE CURVES (57)



COMPARISON OF K-FACTOR [57] AND RATING FACTOR [74]
FOR THE PERFORMANCE OF MECHANICAL DRAFT COOLING TOWERS
FIGURE B-VII-44



GRAPH SHOWING VARIATION OF COST OF MECHANICAL DRAFT COOLING TOWERS WITH WATER FLOW (from Reference 57)
FIGURE B-VII-45

in the surrounding area and could result in problems of corrosion to equipment or damage to plants and trees.

In addition to losses from drift, a certain amount of the water is intentionally removed from the system as blowdown to control the concentration of salts and chemical additives in the cooling water. The amount of blowdown varies with the quality of the makeup water. The amount of heat in this blowdown stream is relatively small.

Aside from the appearance of the physical structure, an additional visual result of usage of cooling towers is the formation of visible plumes of condensed water vapor under appropriate weather conditions. These plumes are formed when the temperature of the moisture-laden air leaving the tower drops below the dew point. With mechanical draft cooling towers, these plumes are close to the ground due to the low tower height, and will drop to the ground under certain wind conditions. With their tall chimneys, natural draft towers produce plumes at 300-500 feet above the ground. Further discussion of plumes is provided in a subsequent section of the report.

Wet Mechanical Draft Towers - Induced Draft - Counterflow

This type of tower, pictured in Figure B-VII-37 is only slightly different from the crossflow type. The air flow is counter to the water flow. This makes the tower taller than the crossflow tower, because additional space must be allowed at the bottom of the tower for the air to enter.

Some advantages of this system are:

1. The coldest water contacts the driest air. The air, as it travels up through the water, contacts progressively warmer water, maintaining the potential for evaporation.

2. The fan forces the air straight up, minimizing air recirculation.

3. Larger fans can be used (up to 18.3 meters (60 feet)).

4. Closer approaches and large cooling ranges are possible.

There are a number of disadvantages also:

1. The small air opening at the bottom of the tower leads to high pressure drops, and subsequently, higher fan horsepower requirements.

2. A more sophisticated air distribution system is required to maintain uniform air flow through the packing.

3. Since the top of the packing is higher above the ground, the required pumping head is higher.

Wet Mechanical Draft Tower - Forced Draft

This tower design, pictured in Figure B-VII-46, is not currently being used to any extent, particularly in the steam electric utility industry. Its principal advantages are:

1. Noise levels and vibration are reduced, since fans are mounted at the base of the tower.

2. Blade erosion is non-existent and condensation in gear boxes is greatly reduced.

3. Fan units are slightly more efficient than induced draft type, since development of static pressure in tower permits some recovery of work.

Disadvantages of the forced draft tower:

1. Fan size is limited to about 3.6 m (12 ft), necessitating multiple fan installations.

2. Baffles are necessary for air distribution.

3. Recirculation of the hot, humid discharge air is a problem, as it can flow back to the low pressure intake.

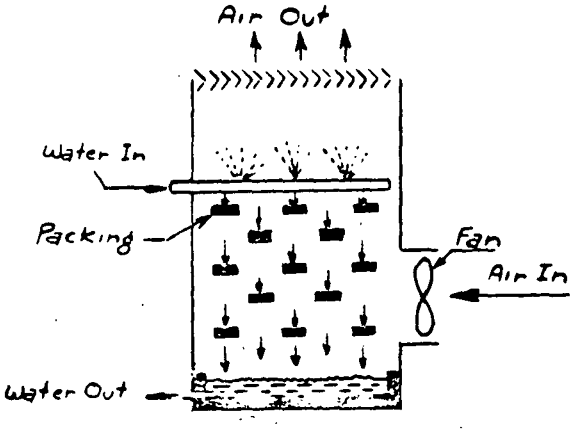
4. During cold weather, ice may form on the fan blades, causing damage and reducing air flow.

A modern adaptation of the type of tower is the fan-assisted natural draft tower, which is discussed under the section on natural draft towers.

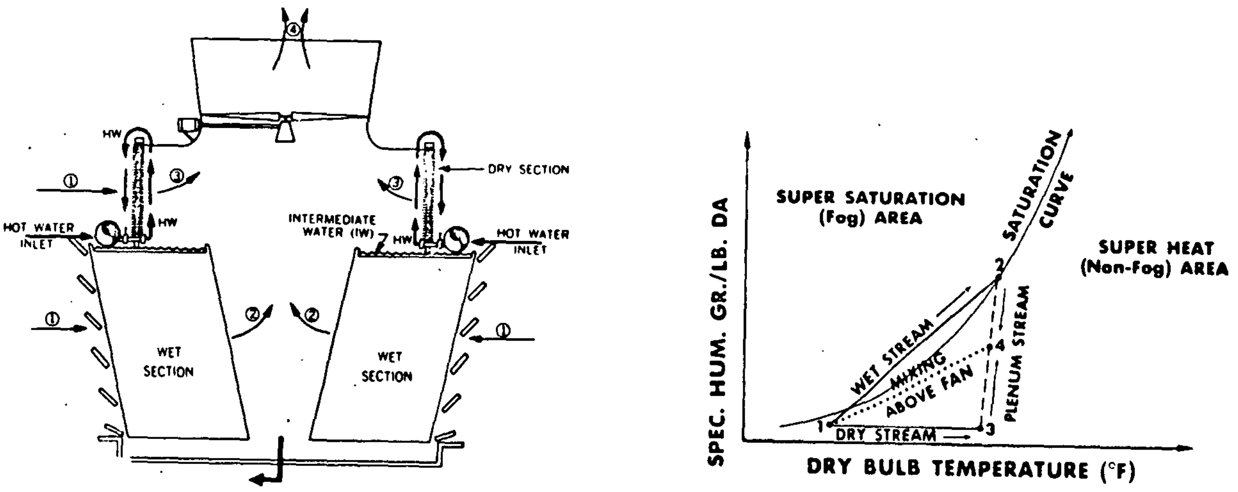
Wet-Dry Cooling Towers

A fairly recent development in the mechanical draft cooling tower is the wet-dry system. This design combines the wet and dry tower principles, as shown in Figure B-VII-47. The concept was originally developed to reduce or eliminate the plumes from mechanical draft towers.

The principles of operation are shown in the psychrometric chart in Figure B-VII-47. The air passing through the dry section is heated along line 1-3. The air passing through



MECHANICAL-FORCED DRAFT COOLING
FIGURE B-VII-46



PARALLEL PATH WET DRY COOLING TOWER PSYCHROMETRICS
FIGURE B-VII-47
(From Reference 128)

the wet section is heated and humidified along line 1-2. When the air from these two sections is mixed in the fan plenum, the condition of the mixture lies along line 2-3, at some point 4. The position of this point is dependent on the relative amount of the two air streams mixed. The relative size of the dry section is dependent on the local climatic conditions as related to the probability of fog formation.

The details of construction of the tower for plume abatement are shown in Figure B-VII-48. Note the summer damper door used to shut off most of the air flow through the dry section during the summer when plume abatement is not required. This shunts the air flow to the wet section during the summer when increased cooling is necessary.

While plume reduction itself can be beneficial, the concept of combining the wet and dry sections opens up possibilities for applications where water consumption considerations are important. By enlarging the dry section, as shown in Figure B-VII-49, the principal cooling occurs in the dry system, with the wet section used only as required. The tower performance in such a situation is indicated on the psychrometric chart in Figure B-VII-49. A contract has been signed for the installation of four wet-dry towers at plant No. 2416. The towers will cool 472,000 gpm of brackish water. Details are given in Reference 391.

Natural Draft Cooling Towers

The natural draft tower, or hyperbolic tower, as it is commonly known, has the advantage that no mechanical energy is required to circulate the air through the tower. The tall chimney is used to develop sufficient driving force between the hot, humid air from the fill and the cooler air outside the chimney. This force difference must overcome the internal resistance to air flow.

$$(pa - pt)\frac{g}{go} \text{ X } h = \text{Pressure drop through packing + tower friction loss + kinetic energy of air leaving the tower.}$$

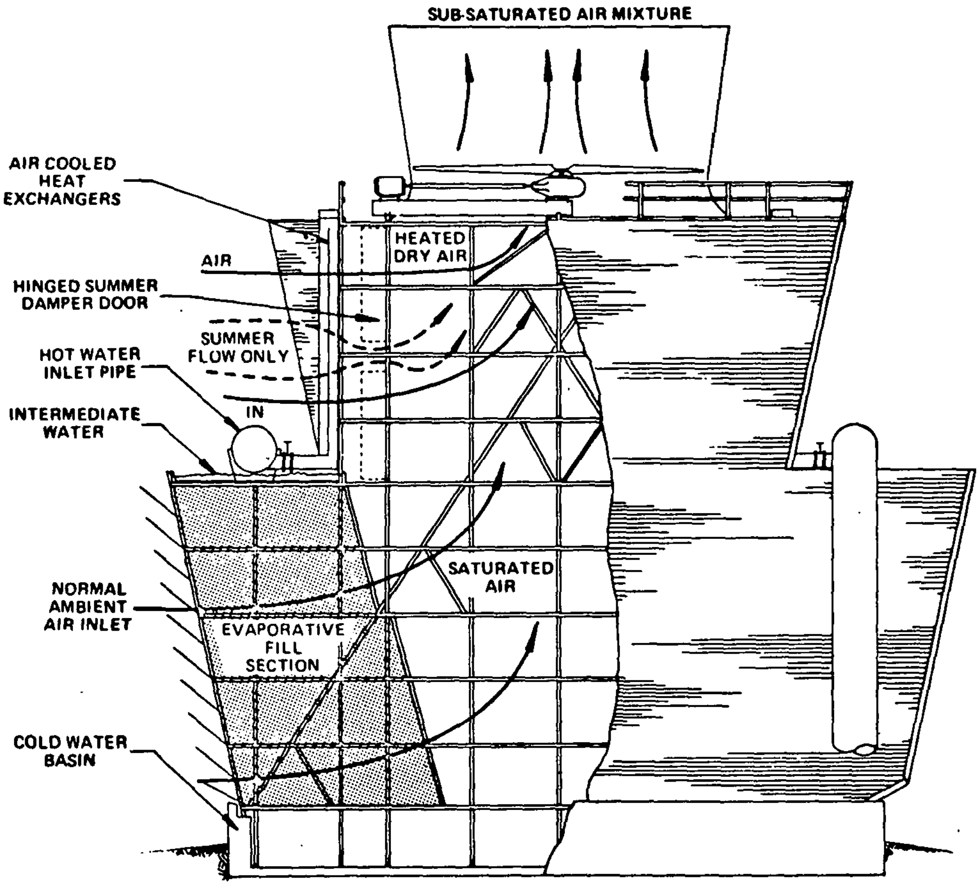
where pa = density of air entering the tower

pt = density of humid air in the tower

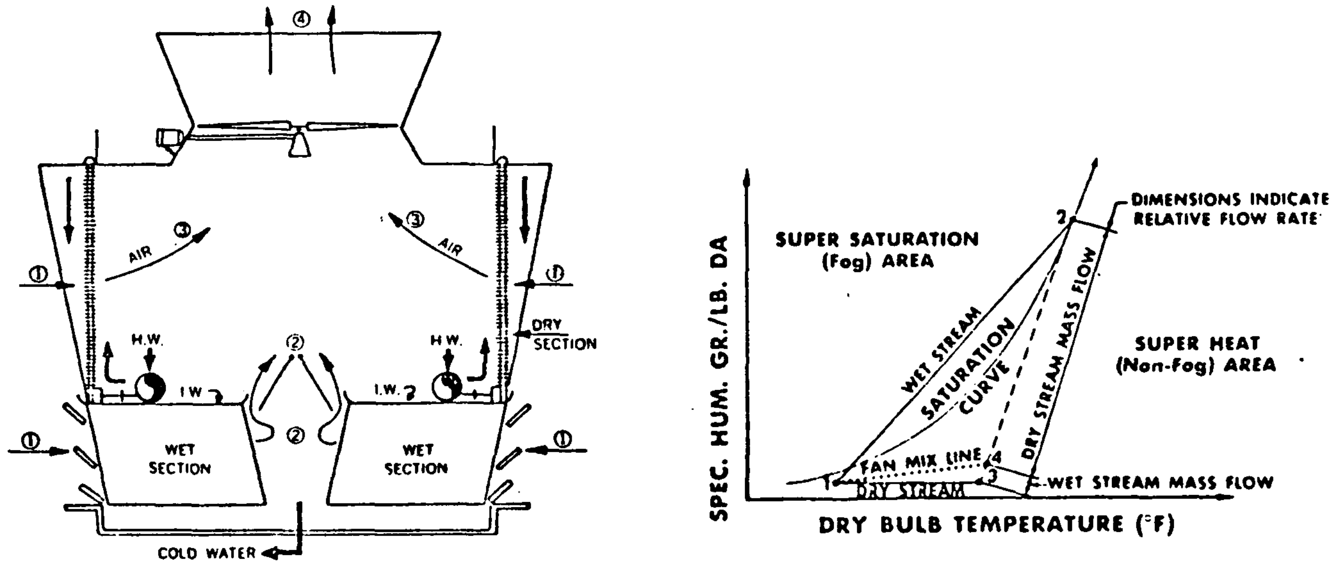
g = gravitational constant at elevation of tower

go = reference gravitational constant

h = height of tower



PARALLEL-PATH WET DRY COOLING TOWER FOR PLUME ABATEMENT
FIGURE B-VII-48
(From Reference 128)



PARALLEL-PATH WET DRY COOLING TOWER (ENLARGED DRY SECTION)

FIGURE B-VII-49 (From Reference 128)

Approximately a tenth of the tower height is utilized for the air-water contact section, the remaining 90% is used solely to develop the required driving force for adequate air circulation. A typical installation, in plant No. 4217, is shown in Figure B-VII-50.

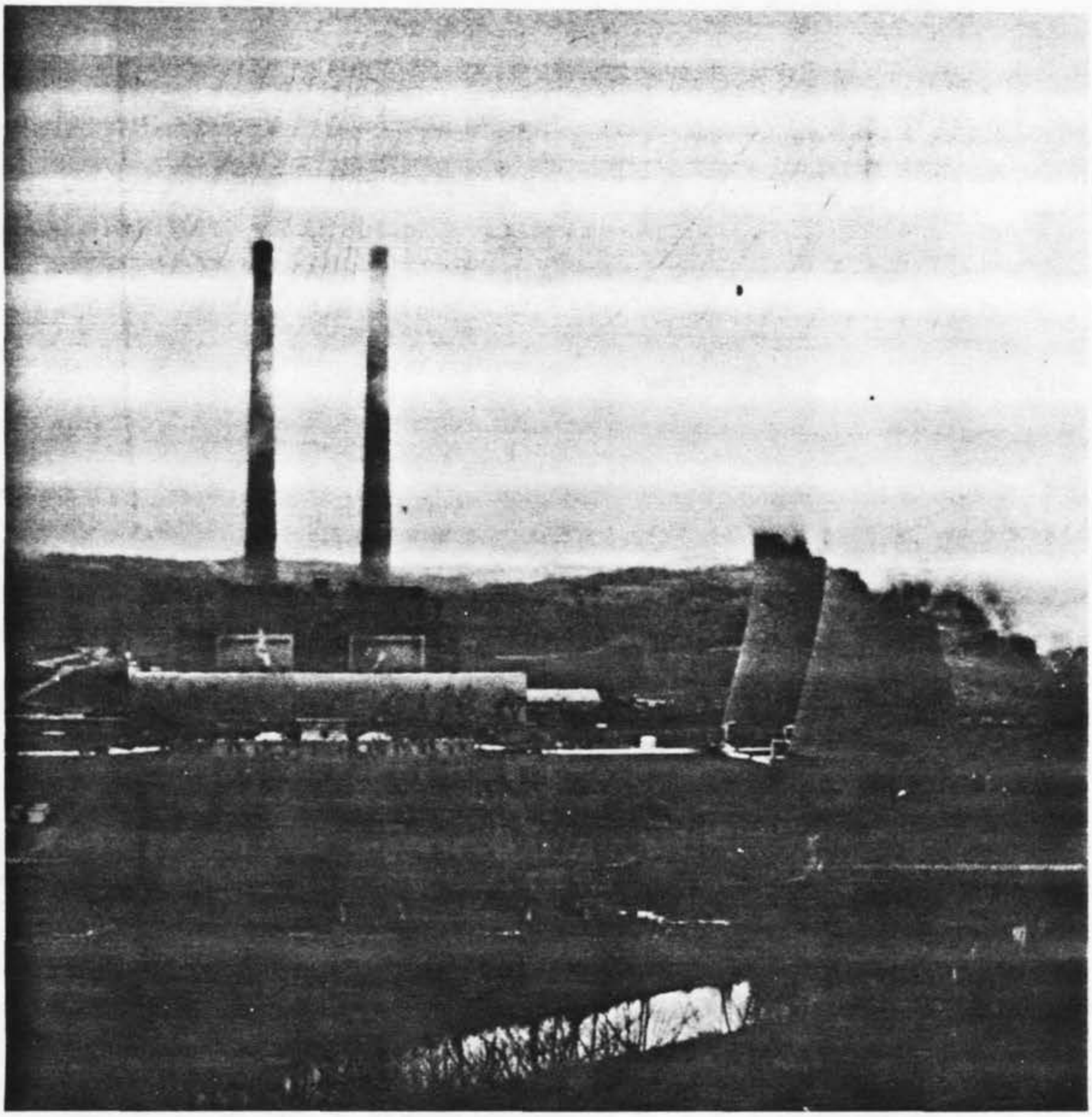
The economical use of natural draft towers is restricted to regions with moderate temperatures and average humidities. In areas such as the Southwest, with high temperatures and low humidities, the potentials for favorable density differences are decreased, resulting in an impractically high chimney to provide circulation for the cooling tower. Climatic conditions in the Southeast and Gulf Coast areas do not favor natural draft towers because of the high wind design loadings.

One of the benefits of the natural draft tower, and perhaps the reason it has become so popular, is that the fog plume is released several hundred feet in the air, and does not create any local hazards due to fogging. However, care should be taken to assure that the stack gases and the tower plume do not intermix, as any SO_2 that may be present in the stack gases may tend to combine with the water in the plume to form damaging acids.

The tower may be constructed for crossflow or for counterflow, with both types in use. The crossflow takes slightly more area, as the fill is located outside the tower proper. Both types may utilize fireproof construction. The fill material employed is asbestos cement.

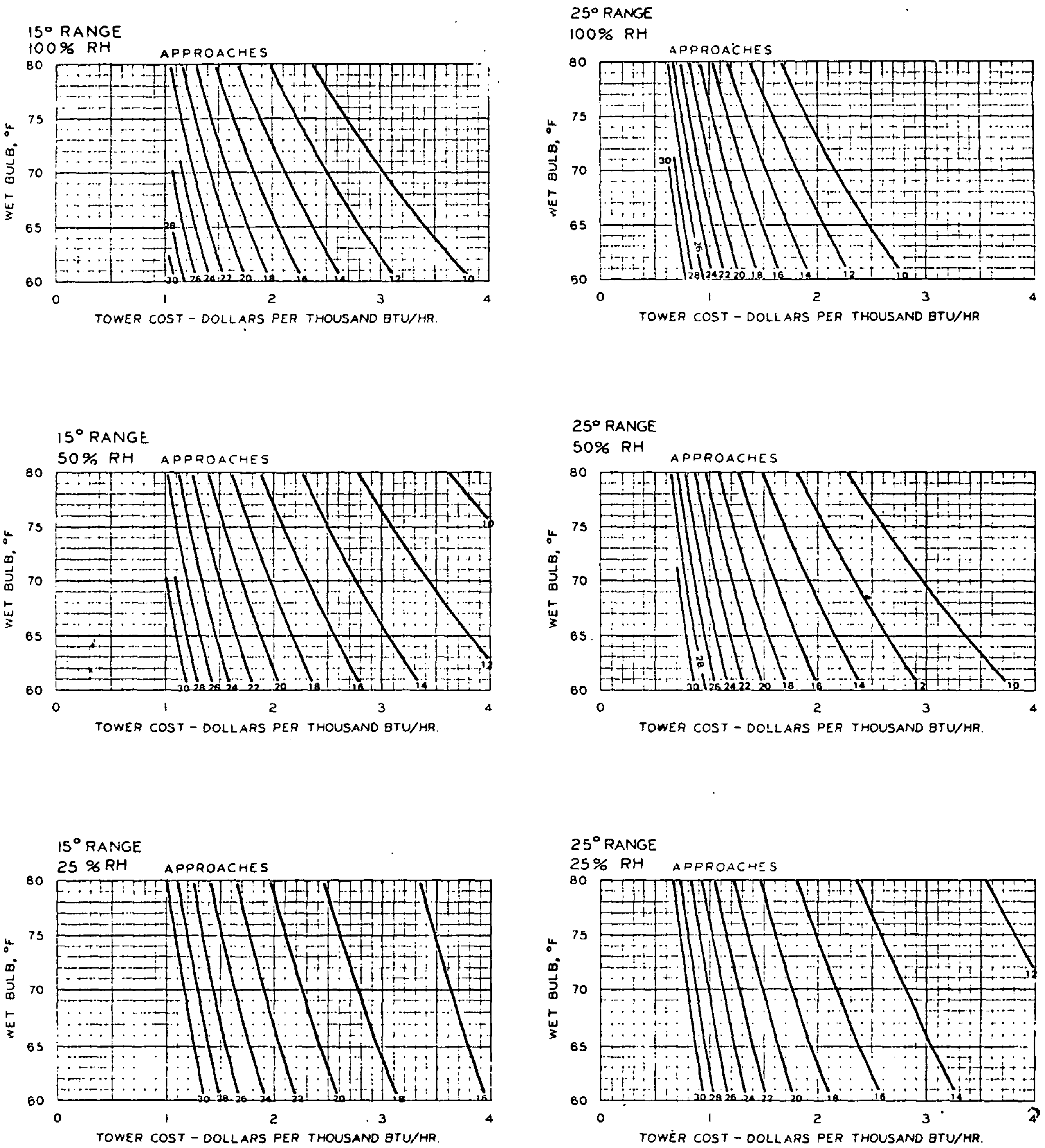
One manufacturer gives some curves for budget estimates of the capital costs of their crossflow towers (see Figures B-VII-51 and B-VII-52). The costs are shown in 1970 dollars, and correspond to the relative humidity, range, approach and wet bulb temperature.

The fan-assisted tower, pictured in Figure B-VII-53 is a modification of the basic natural draft tower which makes it more versatile by combining some features of natural draft towers and mechanical draft towers. The tower looks like a truncated natural draft tower. Forced draft fans are installed in place of the normally large openings for the entrance of air around the bottom of the tower. With the forced draft fans, dependence on the natural chimney effect is removed, considerably increasing the versatility of the tower. The shortened natural draft chimney retains some of



TYPICAL NATURAL DRAFT
COOLING TOWERS
PLANT NO. 4217

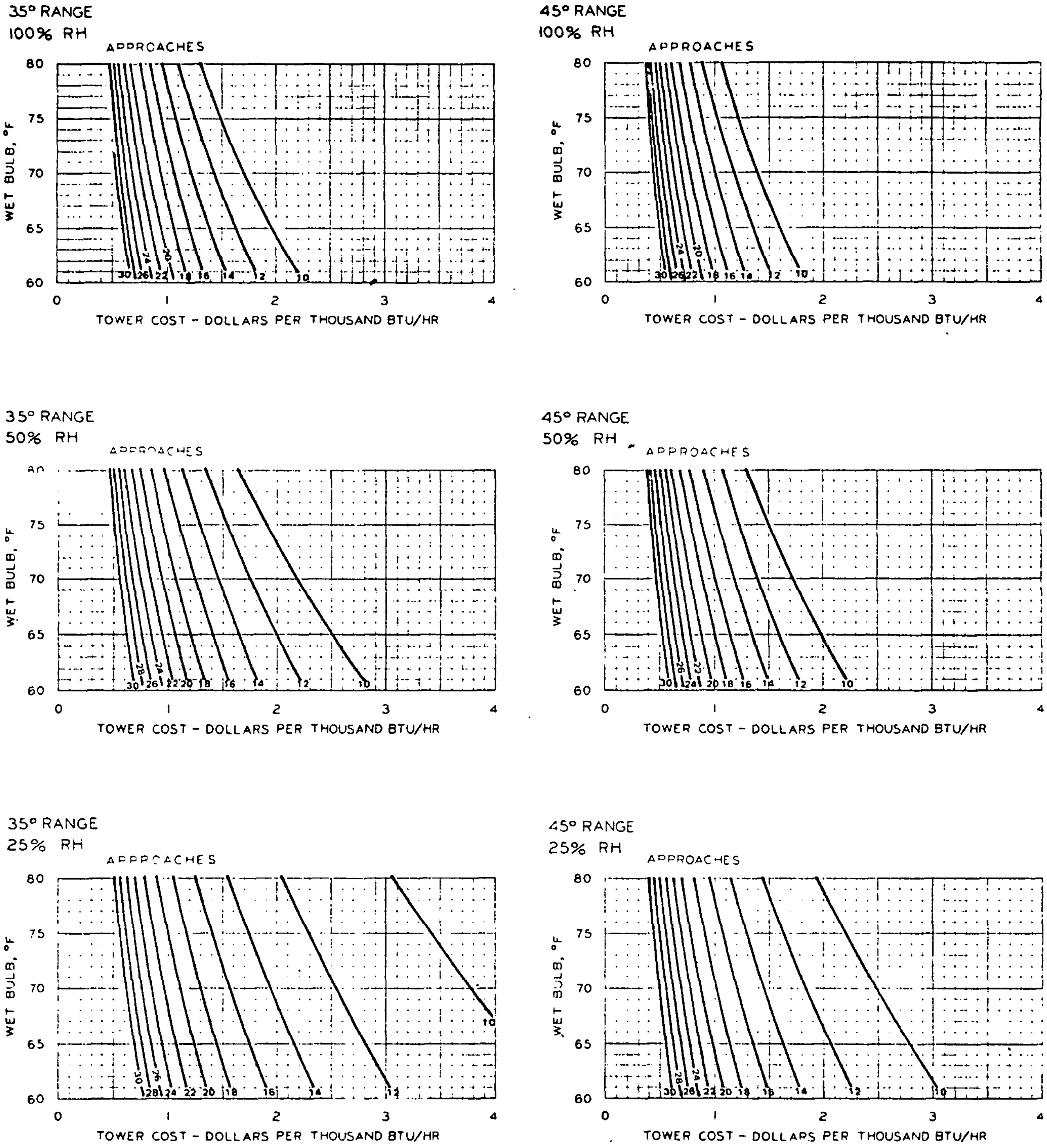
Figure B-VII-50



HYPERBOLIC NATURAL DRAFT CROSSFLOW WATER COOLING TOWERS TYPICAL COST-PERFORMANCE CURVES FOR BUDGET ESTIMATES

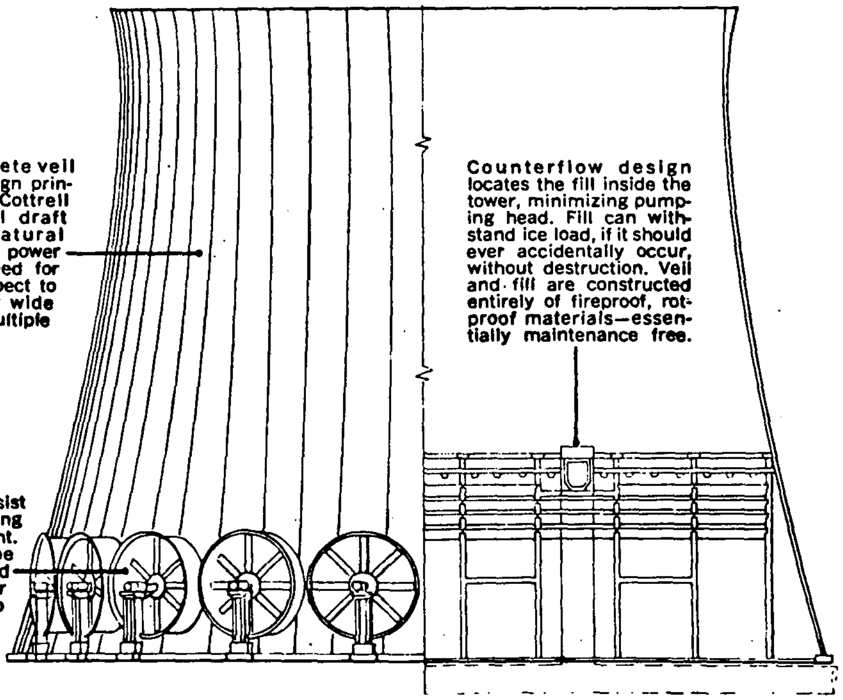
(From Reference 74)

Figure B-VII-51



HYPERBOLIC NATURAL DRAFT CROSSFLOW WATER COOLING TOWERS
TYPICAL COST-PERFORMANCE CURVES FOR BUDGET ESTIMATES
(From Reference 74)

Figure B-VII-52



Reinforced-concrete veil based on same design principles as Research-Cottrell hyperbolic natural draft towers. Creates natural draft, reducing fan power requirement. No need for orientation with respect to prevailing wind, or wide spacing between multiple units.

Counterflow design locates the fill inside the tower, minimizing pumping head. Fill can withstand ice load, if it should ever accidentally occur, without destruction. Veil and fill are constructed entirely of fireproof, rot-proof materials—essentially maintenance free.

Forced-draft fans assist natural draft, reducing required tower height. Tower height can be just enough to avoid problems of vapor plume downdraft to ground level, and of moist air recirculation.

FAN-ASSISTED NATURAL DRAFT COOLING TOWER
FIGURE B-VII-53
(From Reference 358)

the driving force, reducing fan requirements. The height, intermediate between the mechanical draft and natural draft tower, reduces the chance of local hazards from fog. The possibility of recirculation is also reduced. While no fan-assisted natural draft towers are currently operating in the U.S., several towers are operating in Europe.

Dry-Type Cooling Towers

The dry-type cooling tower is used more in the petroleum processing industry than the electric utility industry. Being a closed system, the bulk of the heat is transferred from the petroleum products to air directly, with the final cooling to ambient temperatures being accomplished with evaporative-type towers. The temperatures obtainable with dry-type cooling towers are higher than those economically useful in the electric utility industry. Since no evaporation is involved, the dry bulb temperature governs, not the wet bulb temperature. In spite of this, the utility industry is considering this type of system for specific installations where insufficient water is available for wet towers. There are approximately six electric generating stations using dry-type cooling towers, principally in Europe. The one operating facility in the U.S. is a 20 Mw unit. This is a "direct" unit, with the steam condensing directly in the coils. Construction of a 330 Mw unit at the same site utilizing a dry tower is contemplated. The two types of dry towers, direct and indirect, are shown in Figures B-VII-54 and B-VII-55.

The principal drawback to the use of this type of tower is the higher turbine exhaust pressures which result. Current turbine designs would have to be changed, as most turbines are designed for a maximum turbine exhaust pressure of 127 mm Hg (5 in. of Hg abs) whereas with dry-type cooling towers, the maximum turbine exhaust pressure would range from 200 to 380 mm Hg (8 to 15 in. of Hg). Dry bulb temperatures range from 5.5° to 20°C (10° to 35°F) above the wet bulb temperature. Due to the higher heat transfer equipment costs, dry-type towers optimize at higher approaches than wet towers, additionally increasing the turbine exhaust pressure.

A temperature diagram for an indirect, dry cooling tower is shown in Figure B-VII-56. In dry cooling towers the initial temperature difference (ITD) is used as a design parameter. The ITD is the difference between the saturated steam temperature of the turbine exhaust and the temperature of ambient air entering the cooling tower. The corresponding

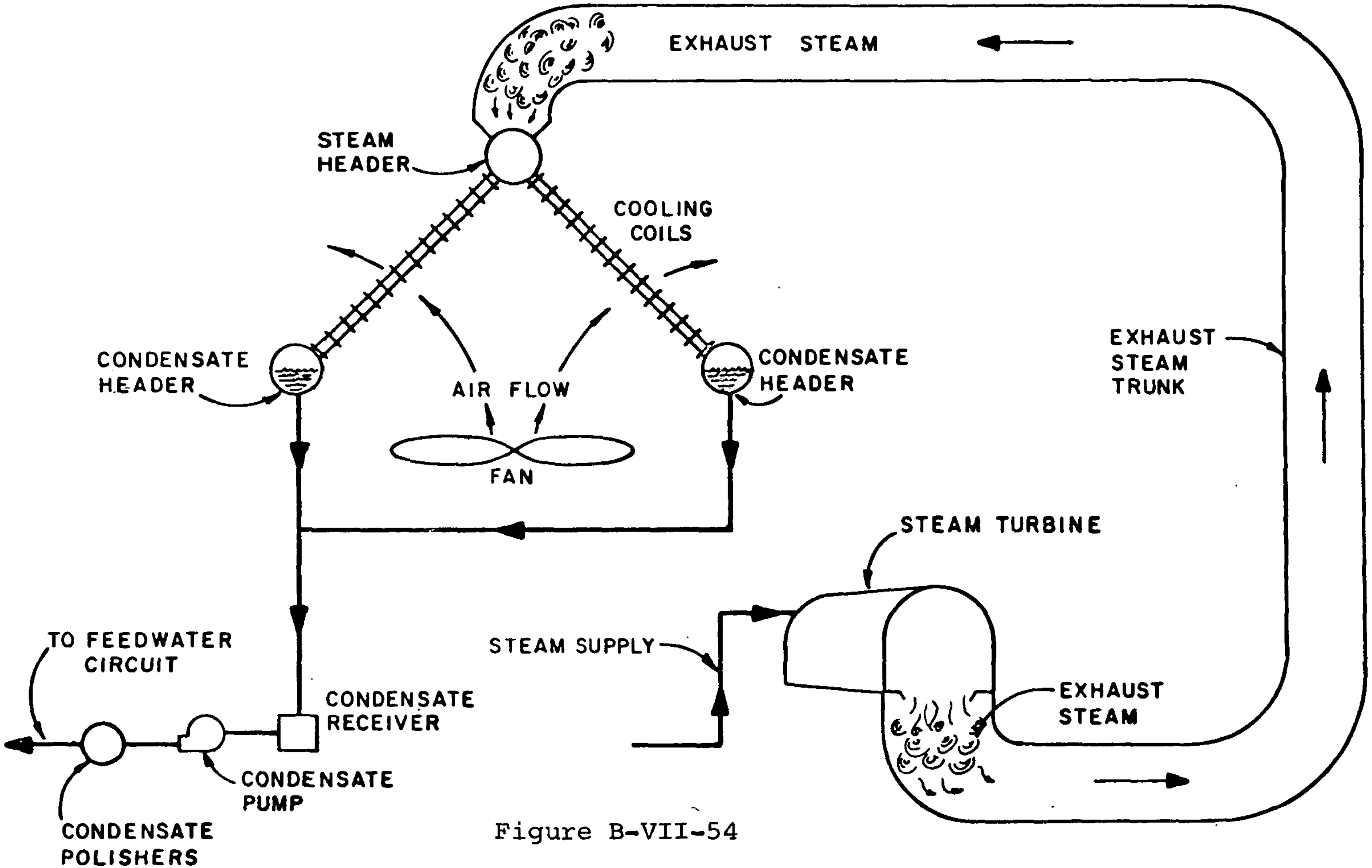


Figure B-VII-54

DIRECT, DRY-TYPE COOLING TOWER CONDENSING SYSTEM WITH MECHANICAL DRAFT TOWER[241]

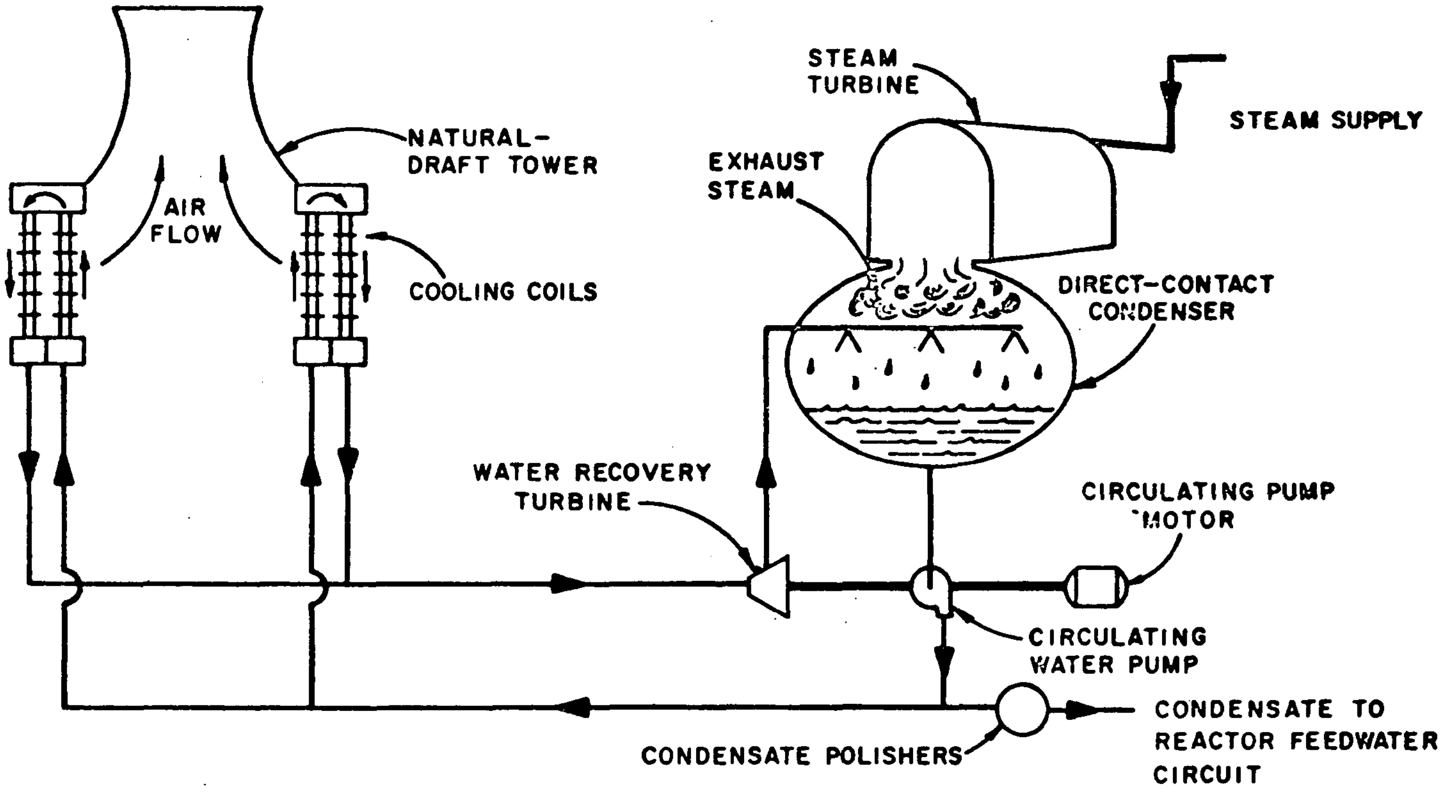


Figure B-VII-55

INDIRECT, DRY-TYPE COOLING TOWER
CONDENSING SYSTEM WITH NATURAL-DRAFT TOWER [241]

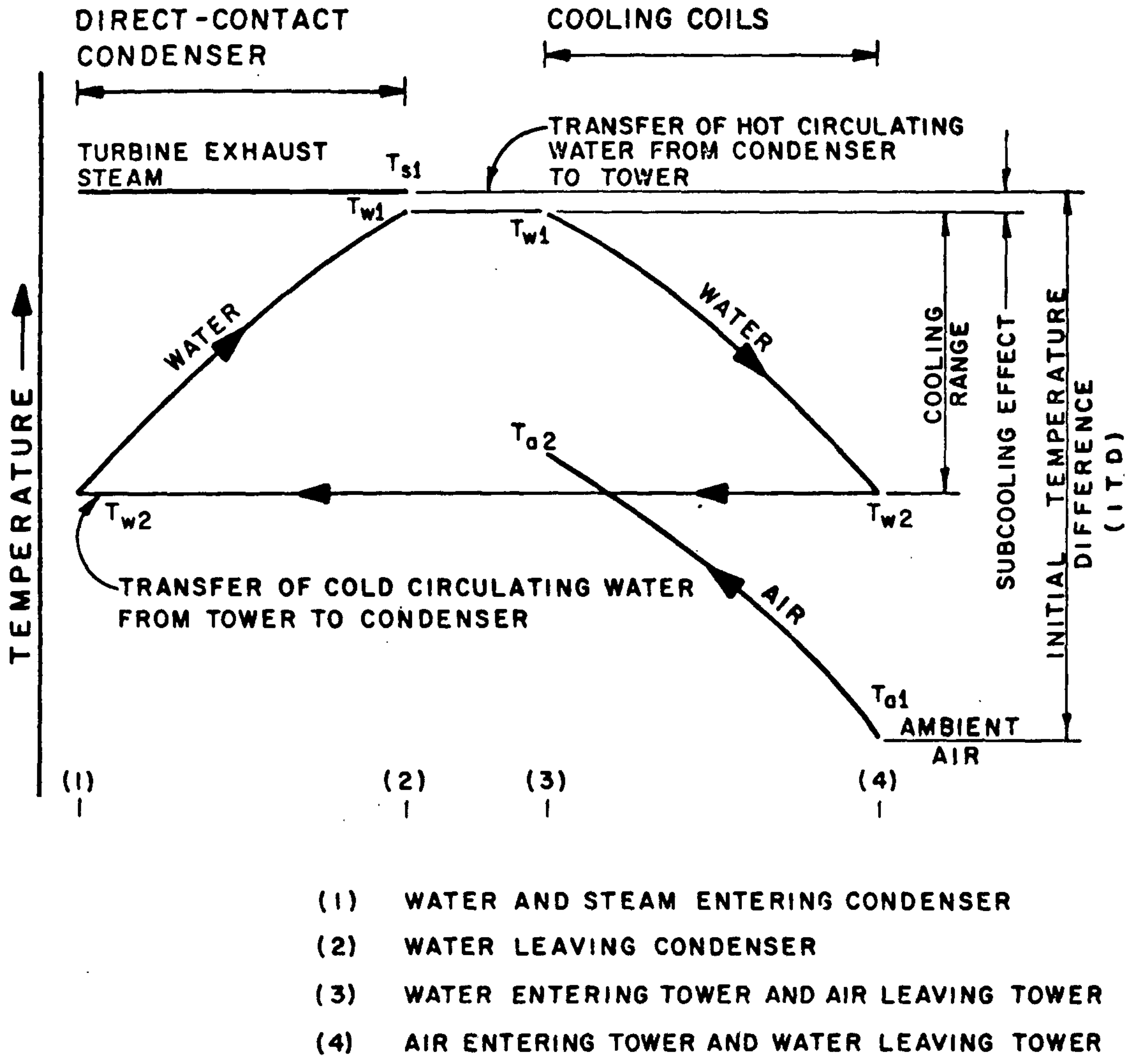


Figure B-VII-56

TEMPERATURE DIAGRAM OF INDIRECT DRY COOLING TOWER HEAT-TRANSFER SYSTEM [240] temperature difference in the wet tower system is the sum of the approach to wet bulb, cooling range and terminal temperature difference (TTD).

Assuming the design parameters typical of an eastern U.S. location (dry bulb temperature equal to 32°C (90°F) and wet bulb temperature of 25°C (76°F)), the turbine exhaust pressures corresponding to a wet system and corresponding to a dry system can be compared. For the wet tower, typical values of the cooling range, approach, and terminal temperature difference are 12, 11 and 5.5°C, respectively.

The sum of these is 29°C (52°F), which yields a condensing temperature of 53.5°C (128°F) with a corresponding pressure of 14.5 kN/sq m (4.3 in. of Hg abs) in the wet system.

A corresponding dry-type tower with an ITD of 29°C (52°F) with the ambient temperature of 32.2°C (90°F), gives a condensing temperature of 61.1°C (142°F) with a corresponding pressure of 20.4 kN/sq m (6.2 in. of Hg abs). This is almost 50% higher than the condensing pressure in the wet system.

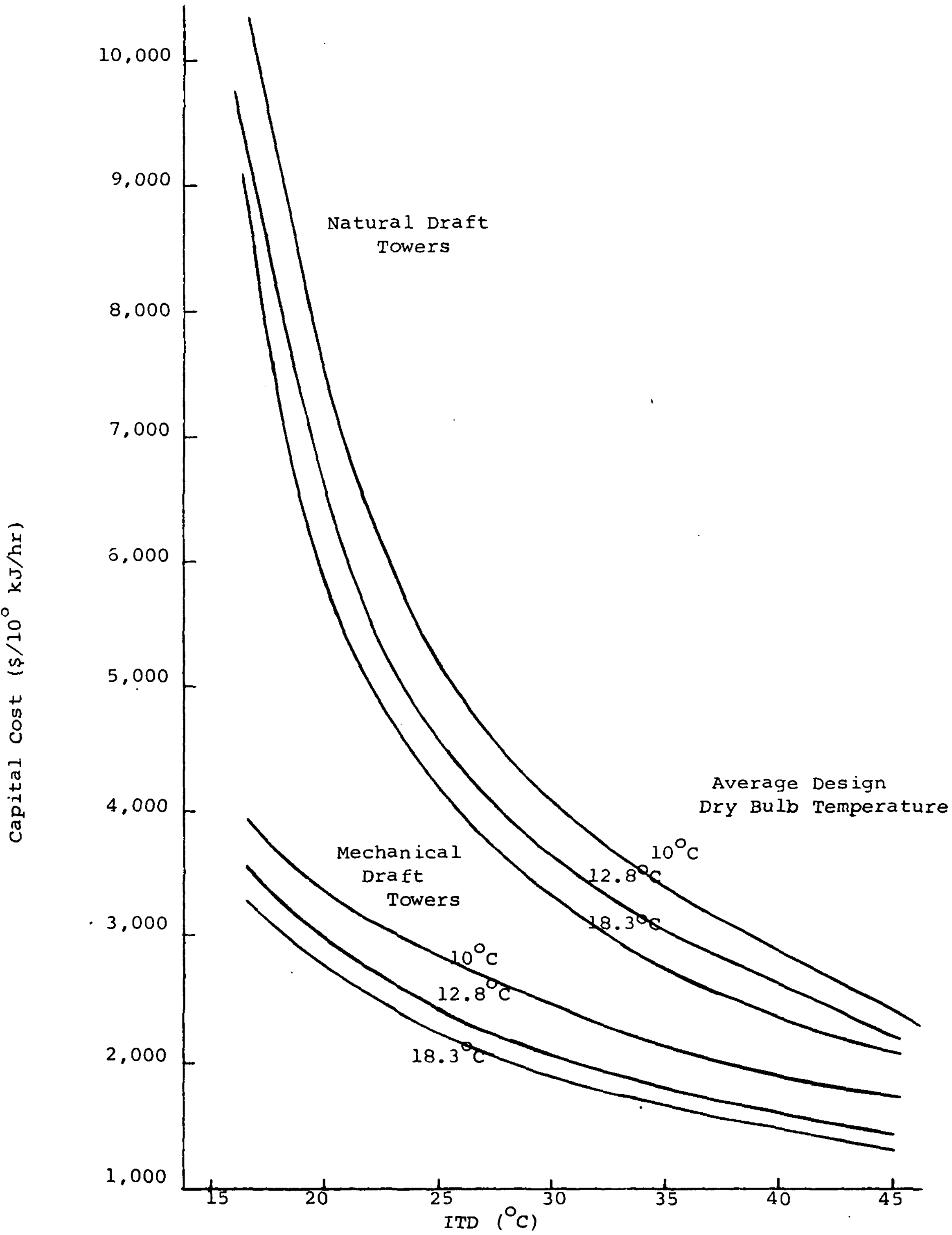
A number of economic studies have been made comparing the cost and benefits of dry-type towers with wet towers. Some data from one of these has been used to calculate the cost curves shown in Figure B-VII-57. The curves are for the cooling tower only. The variation in cost shown is due primarily to the variation in construction costs in the different locations, Northeast, West, and Southeast rather than to variations in the design dry bulb temperature indicated on the figure.

The direct contact condenser is considerably cheaper than the normal shell and tube condenser, as it does not require expensive alloy tubes. A typical direct contact condenser is shown in Figure B-VII-58. The lower condenser costs particularly make up for the greatly increased cost of the cooling tower.

There are a number of other benefits from the dry-type cooling tower.

1. No water usage, thus no large makeup requirements and no buildup of solids, chemicals, etc., in the water as in an evaporative tower.

2. There is no possibility of fogging and there are no drift losses to deposit minerals on the surrounding territory.



REPRESENTATIVE COST OF HEAT REMOVAL WITH DRY TOWER SYSTEMS (from Ref. 240) FOR NUCLEAR PLANTS
FIGURE B-VII-57

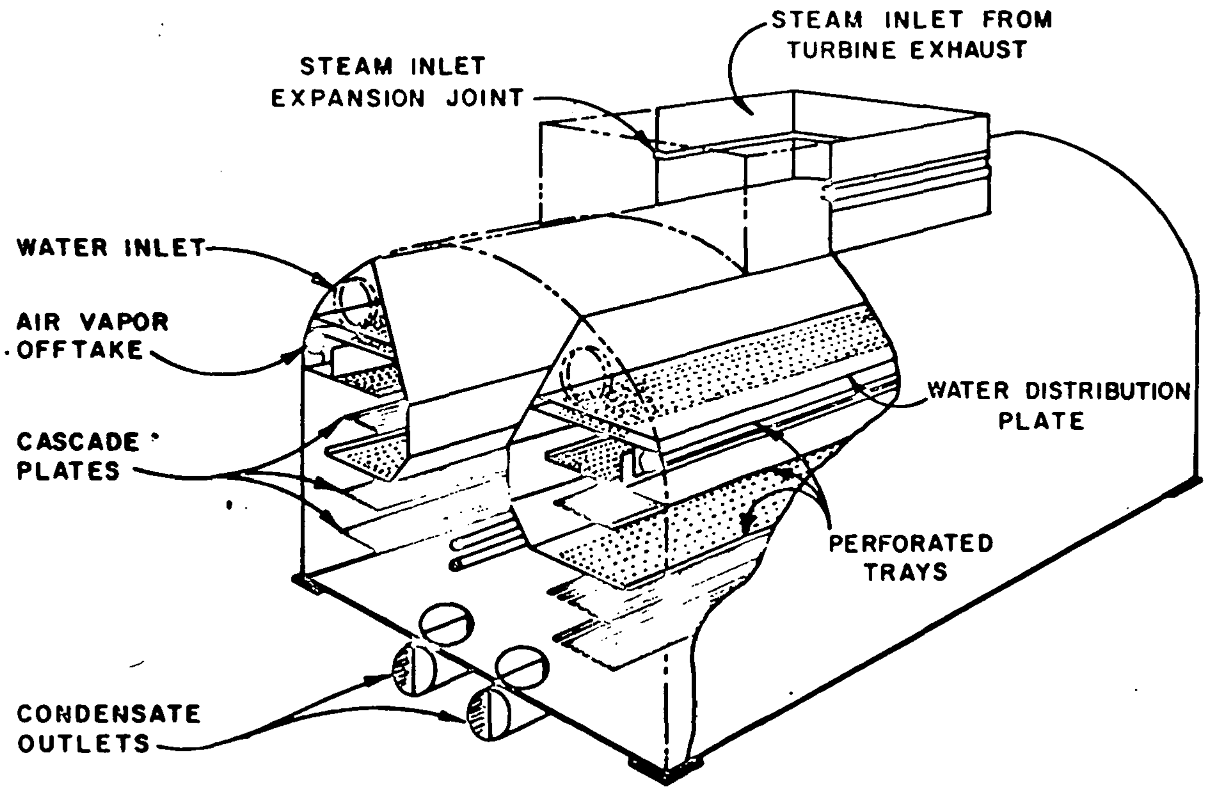


Figure B-VII-58

STREAM TYPE

DIRECT CONTACT CONDENSER[240]

On the other side of the ledger, there is a significant loss in plant efficiency due to the higher turbine exhaust pressures. Figure B-VII-59 gives the expected increases in fuel consumption and decrease in power output for a nuclear and fossil-fueled plant, provided the turbine could operate at the higher pressures indicated. Not only is there a loss in efficiency, but the maximum plant capacity is also reduced.

Other Tower Types Used Outside the U.S.

Conventional multicell evaporative mechanical draft cooling towers and evaporative natural draft cooling towers are used outside the U.S., as are several types of dry cooling towers. Another type of tower widely used outside the U.S. is the circular base evaporative mechanical draft cooling towers. The basic design of this type of tower is shown is Figure B-VII-60. One firm has supplied hundreds of these towers, in sizes up to approximately 40,000 metric tons per hour circulating water rate. A tower at the Staudinger plant handing 40,000 metric tons/per hour has a base diameter of 61 meters and a height of 50 meters. This firm has supplied one circular based mechanical draft tower to a U.S. utility for plant no. 4210.[400] Figure B-VII-61 shows the use of 34 circular mechanical draft towers with fan diameter up to 21 meters and one natural draft cooling tower of 115 meters height for units sized between 100 and 300 megawatts at the Frimmersdorf plant.[401]

Mechanical draft cooling towers of circular base with forced draft fans have been supplied by the firm discussed above for 5 powerplants. The largest of these are 2 towers at the Biblis plant where 105,000 metric tons per hour of cooling water is circulated in each tower. The towers are 80.5 meters in diameter and 80 meters in height.[400]

A novel cooling tower is being constructed under financing of the West German government. This tower, shown in Figure B-VII-62, consists of a center mast 575 feet tall, with an upper ring 290 feet in diameter and a lower ring 490 feet in diameter. These rings are connected by cables to give a hyperbolic shape as shown, with a minimum diameter of 260 feet. The network of cables will be covered with aluminum panels to complete the tower. It is hoped that this method of construction will eliminate the size constraints imposed by the present reinforced-concrete construction. The first tower is being designed and constructed by two large German cooling tower firms, Balke-Durr and GEA, working together. The unit will be at the Schmehausen station, cooling a 300 Mw unit, but will be designed to accommodate a 500 Mw unit.[389]

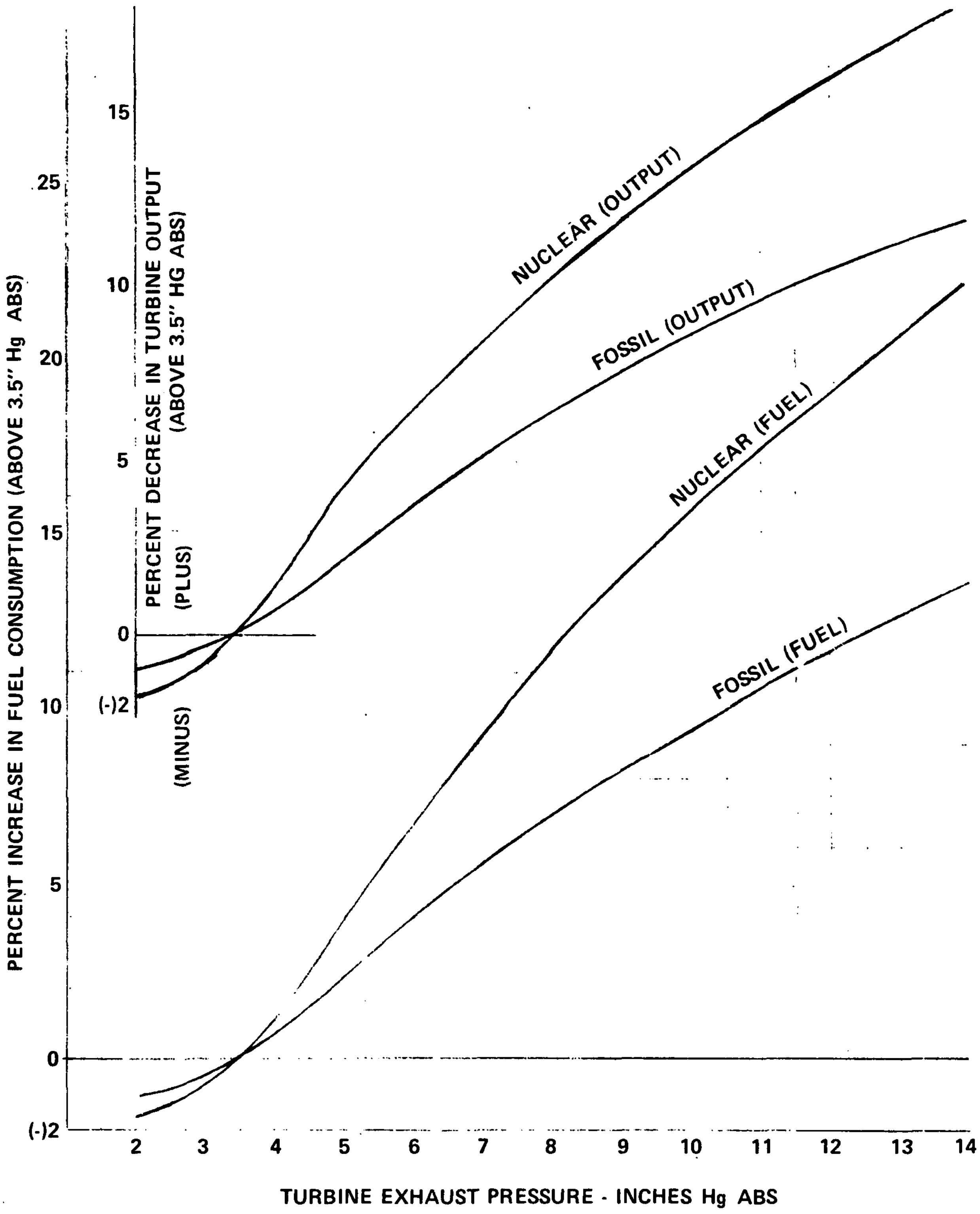
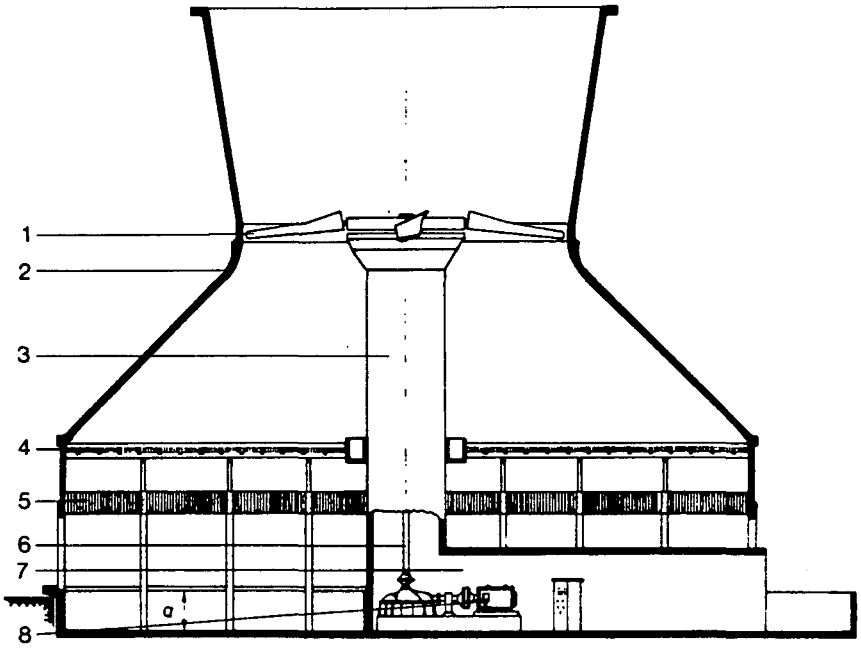
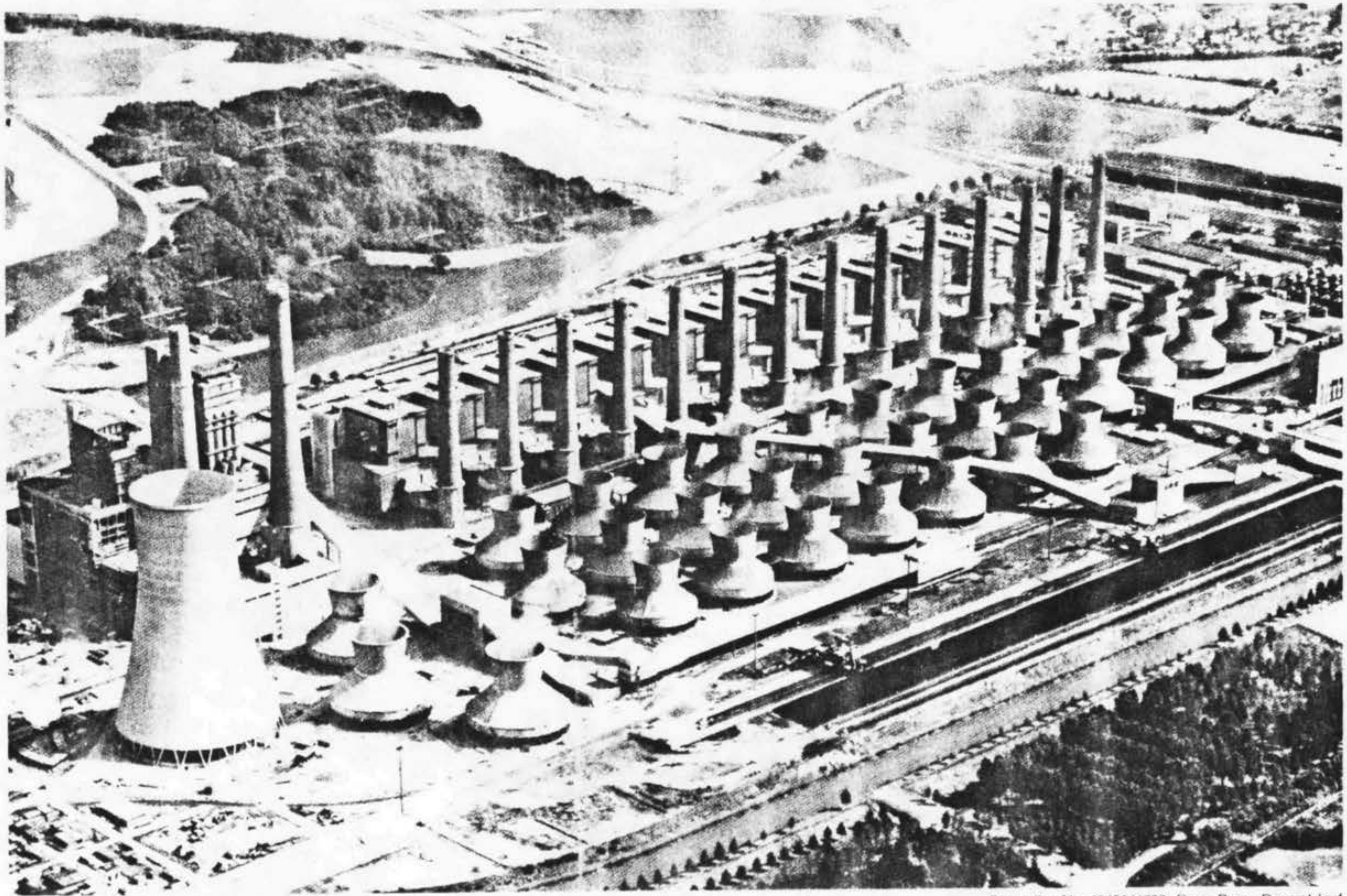


FIGURE B-VII-59 EFFECT OF TURBINE EXHAUST PRESSURE ON FUEL CONSUMPTION AND POWER OUTPUT (FROM REFERENCE 269)



1 Fan
2 Tower shell
3 Central shaft concrete housing
4 Water distribution system and drift eliminator
5 Cooling fill material
6 Vertical driving shaft
7 Dry chamber for mechanical equipment
8 Drive gear with motor and turbo coupling

Figure B-VII-60 Section Across a Circular Mechanical Draft Cooling Tower [400]



Freigabe Nr. 18/80/1733 Reg.-Pras. Dusseldorf

Figure B-VII-61 Frimmersdorf Power Station[401]

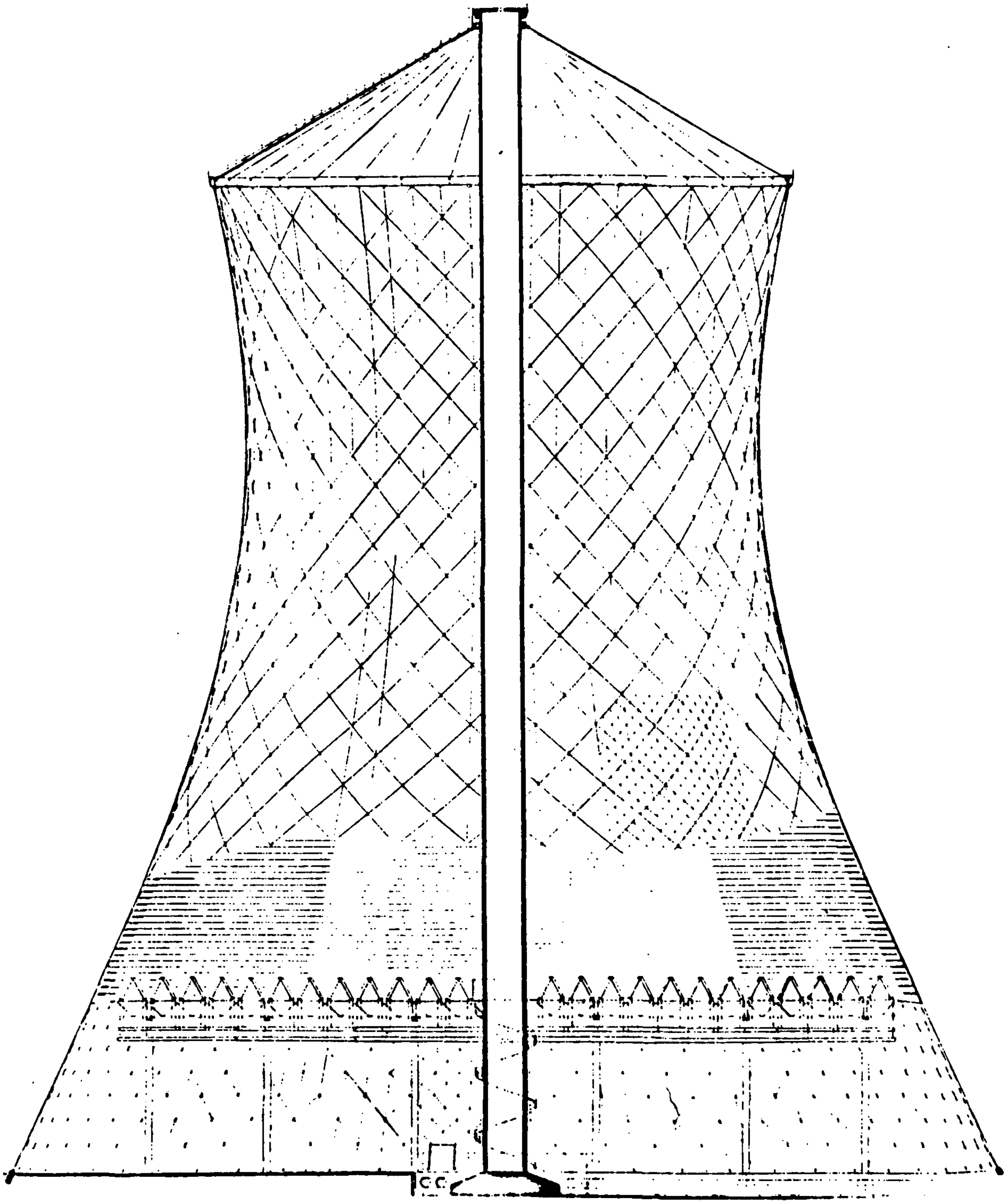


Figure B-VII-62 Cable Tower

Balcke-Durr has also supplied large cooling towers with noise suppression. At Bewag's Lichterfelde plant in Berlin, 3 circular forced draft towers circulating 12,000 metric tons per hour (150 megawatts) each of water were built from 1972 to 1974. Noise level guarantees were 60, 55, and 50 db(A) at 5 meters, respectively, for the first, second and third towers constructed. The towers are 35 meters in diameter and 50 meters in height. See Figure B-VII-63. At Kkw's Biblis plant, 2 circular forced-draft towers circulating 105,000 metric tons per hour each of cooling water are planned for installation in 1975 to 1976. A noise level is guaranteed of 19 db(A) at 1,000 meters. The towers are 65 meters in diameter and 80 meters in height. At Stadtw.'s Duisburg plant, 1 circular forced-draft tower circulating 48,000 metric tons per hour of cooling water is plannned for installation in 1975/1976. A noise level is guaranteed of 25 db(A) at 500 meters. The tower is 55 meters in diameter and 48 meters in height.

In the case of the Lichterfelde plant in Berlin, the noise levels of the towers were based on a noise regulation which limited noise to 35 db(A) at night at a distance of 130 meters from the plant. This plant was constructed at a site in close proximity to a high-density residential area. Site selection was limited by the unique territorial constraints of West Berlin.[404]

Survey of Existing Cooling Water Systems

The FPC Form 67 Summary Report for 1970 summarizes the use of once-through cooling, cooling ponds, cooling towers, and combined systems by number of plants and by installed capacity (Table B-VII-3). In 1970 about 23% of the plants (18%) of installed capacity) used cooling ponds or towers. Data submitted to the FPC by Regional Reliability Councils indicates that cooling ponds or cooling towers are already committed for over 50% of the total capacity of units to be installed 1974 through 1980. See Table B-VII-4. Table B-VII-5 gives the total installed capacity, fossil-fueled and nuclear, which is committed to cooling towers, supplemental cooling, or once-through cooling, for plants 300 Mw and larger under construction as of April 1, 1974.

Site visits were made to a number of steam electric generating plants. One purpose of these visits was to observe actual operations of cooling water systems and to discuss operating experiences with plant personnel. Design and operating data were obtained for these plants, including basic plant information, type of cooling system,

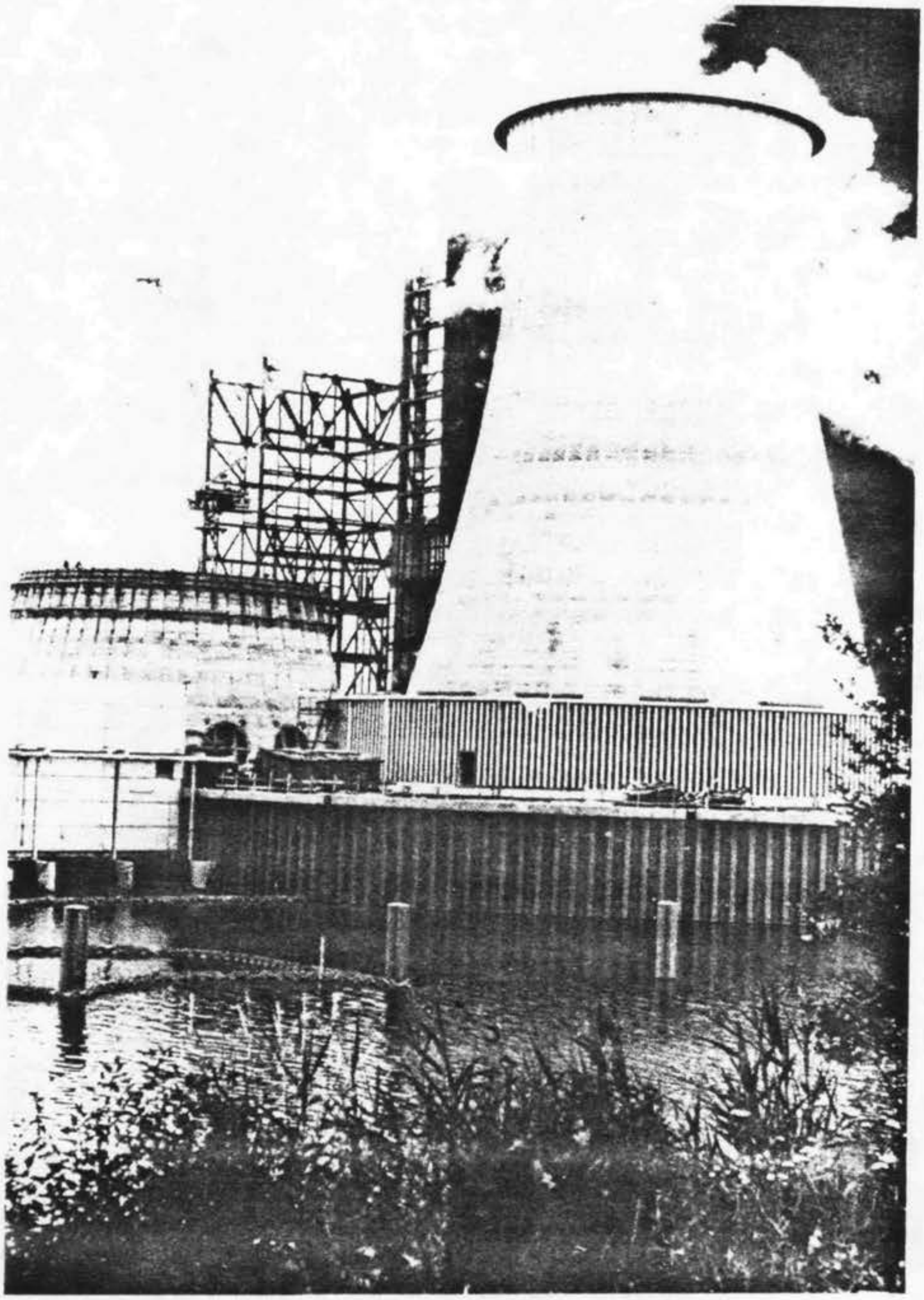


Figure B-VII-63 Cooling Tower with Noise Control at Lichterfelde Plant[403]

Table B-VII-3

USES OF VARIOUS TYPES OF COOLING SYSTEMS[233]
Based on FPC Form 67 for 1969, 1970

Type of Cooling	Number of Plants, % total		Installed Capacity, % of total	
	1969	1970	1969	1970
Once-through, fresh	49.8	49.4	50.5	50.1
Once-through, saline	18.9	18.5	23.5	22.8
Cooling ponds	5.4	5.7	5.9	6.7
Cooling towers	17.2	17.5	10.9	11.2
Combined systems	8.7	8.9	9.2	9.2

Table B-VII-4

EXTENT TO WHICH STEAM ELECTRIC POWERPLANTS ARE ALREADY COMMITTED TO THE APPLICATION OF THERMAL CONTROL TECHNOLOGIES[361]

CONTROL TECHNOLOGY	ASSOCIATED GENERATING CAPACITY, THOUS. MW	
	IN ACTUAL USE IN 1973	COMMITTED FOR UNITS INSTALLED 1974 THROUGH 1980
No Control (Once-Through)	230	60
Controlled	110	130
● Cooling Towers	50	80
● Cooling Ponds	30	40
● Combinations	30	10
Unknown	-	30

Table B-VII-5

COOLING SYSTEMS FOR PLANTS 300 Mw AND LARGER UNDER CONSTRUCTION (April 1, 1974)*

TYPE OF COOLING	FOSSIL-FUELED Mw	NUCLEAR Mw	TOTAL	
			Mw	% Total
Cooling Towers	46,276	30,428	76,704	38.3
Supplemental Cooling	6,466	8,518	14,984	7.5
Once-Through	56,334	52,587	108,921	54.2
Total	109,076	91,533	200,609	

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* Source: May, 1972 FPC printout of utility responses to FPC Order No. 303-2

quantitative data such as flow rate, temperatures, and approximate cost data.

Plants visited were chosen to result in a spectrum of fossil-fueled and nuclear units, geographical locations, sizes, and types of cooling systems. Table B-VII-6 presents a list of plants visited in the U.S. and the basic cooling water data collected. A few plants that were visited are not included in this list as a result of incomplete data.

Many of these plants have once-through or open condenser cooling water systems. Sources of cooling water for plants visited include lakes, wells, rivers, and estuaries. Generally, the water in these plants is discharged at the temperature at which it leaves the condenser. However, several "helper" systems were observed, where the water is cooled before being returned to the source, using a cooling tower or other device. One plant discharged cooling water to a municipal water system.

Some of the plants that have been designed with or have used once-through cooling systems are installing closed cooling systems as a result of environmental regulations. In most instances, a small loss of plant capacity and efficiency has resulted when this change has been made.

Other plants visited have closed condenser cooling water systems, where the cooling water is not discharged to the receiving water, in order to avoid a thermal impact, but is recirculated utilizing cooling ponds and cooling towers.

A number of plants use cooling ponds. These may be artificially constructed lakes, or may be canal shaped. If available land is limited, a smaller pond may be constructed by utilizing spray modules. Among the plants visited with conventional cooling ponds, operation generally appeared satisfactory, and as predicted. Some plants using spray ponds, however, seem to be having difficulties in maintaining satisfactory operation with these units.

Cooling towers are also used in a number of cases for cooling the condenser cooling water in closed recirculating systems. Both mechanical draft and natural draft wet towers were observed. Natural draft towers seem to have been specified in cases where there was concern over possible fogging effects from mechanical draft towers. Performance of plants with cooling towers appears to have been satisfactory in all cases.

Table B-VII- 6

COOLING WATER SYSTEMS DATA

PLANTS VISITED

Plant ID	Type of	Plant	Cooling Tower					Water	Cooling Pond or Lake					Average	Once Through System				Discharge	
		Capacity	Type	Height		Diameter		Range	Type	Surface Area		Volume		Time	Length of Pipe		Diameter of Pipe			
Code No.	Fuel	MW		Ft.	Meters	Ft.	M	°F	of Pond	Acres	$M^2(10^3)$	Acre Ft.	$M^3(10^3)$	%	Ft.	M	Ft.	M	Type	Comments
0640	NUCLEAR	916	Natural Draft	425	129.5	325	99.6	28												
1201	OIL & GAS	139.8													850	250	4	1.22	Gravity	
1201	OIL & GAS	792							Artifical	1100	4460	9350	11556	100						
5105	OIL	1386							Spray Canal	7.35	29.8									
2525	OIL	1165							Spray Canal	14.1	57.17	132	163.15		800	243.84	6(Inlet) 10(Outlet)	1.828 3.048	Gravity	9 mos.once thr 3 mos.spr canal
0801	COAL & GAS	300							Natural Lakes	536.63	2176	11234.3	13885						Gravity	once through
1209	COAL & GAS	820																		units 1&2
1209	NUCLEAR	1456							Artifical Canal	3860	15652	20,000	24719	100						canal will be used by all 4 units
2612	NUCLEAR	700	Mechanical Draft	62	18.89	48	14.63	30							3300	1005	11	3.352	Gravity	Length of tower 650 ft. two towers are used
4217	COAL	1640	Natural Draft	323	98.45	247	75.28	28												
4846	COAL	1150							Artifical Lake	2353	9541	50600	62541							
3713	COAL	2137							Artifical Reservoir	32510	131830	1093600	135167							
3626	COAL	290							Natural Lake						356	108.5	0.75	0.228	Gravity	
1723	NUCLEAR	1618													3619	1103	16	4.876	Multiple Diffuser Systems	spr canal will be installed to replace dif sys.
2512	OIL	542.5													250(Inlet) 235(Outlet)	76.2 71.62	5.5(IN) 7.5(OUT)	1.676 2.28	Gravity Plume Outfall	
3115	OIL & GAS	644.7																		
3117	NUCLEAR	457													40(Inlet) 15(OUT)	12.19 4.57	5.5(IN) 7.5(OUT)	1.676 2.28	Gravity Type	Concrete Tunnel
2527	OIL	28													80	24.38	4.5	1.51		
0610	OIL & GAS	750							Spray Pond	28	113.54	171	211.35							
2119	COAL	2534	Natural Draft	437	133.2	311	94.8	27.7												3 such towers for 3 Units

Effluent Heat Reduction for Closed-Cycle Systems

The effluent heat reduction achievable by closed-cycle evaporative cooling systems, as a fuction of the cycles of concentration is given in Tables B-VII-7, 8, compared to a once-through system and a helper tower system, respectively.

Table B-VII-7

EFFECT OF CYCLES OF CONCENTRATION ON COOLING SYSTEM LOSSES, MAKEUP REQUIRED, REDUCTION IN EFFLUENT HEAT Reference 389 (1,000 megawatt unit)

Cycles of Concentration (a)	Evaporation Rate, m^3/hour (b,c)	Drift, Leakage and Blowdown, m^3/hour (c)	Makeup Required, m^3/hour	Percent Reduction in Effluent Heat Over Once-through System
1.5	1230	2460	3690	95.7
2.0	1230	1230	2460	97.1
3.0	1230	615	1845	97.9
4.0	1230	410	1640	98.1
6.0	1230	245	1475	98.3
8.0	1230	175	1405	98.4
10.0	1230	135	1365	98.4

Power plant thermal efficiency assumed to be 40 percent.

(a) Recirculation rate is 86,260 m^3/hr. Heat duty is 3.81 billion BTU/hr and temperature range is 11.1°C (20.0°F).

(b) Assumed heat transfer is 75 percent evaporative, 25 percent sensible

(c) m^3/hr x 4.4 equals gpm.

Table B-VII-8

Effect of Cycles of Concentration
on Heat Discharge Rate
From a 1,000 mw Power Station 389

Cycles of Concentration(a)	Blowdown Rate, m3/hr(b,c)	Heat Discharge for Temperature Differences Between Receiving and Blowdown, million BTU/hr			Percent Reduction Over Helper Tower Assisted Once-Through System(d)
		ΔT=1°C	ΔT=5°C	ΔT=10°C	
1.5	2460	9.37	48.66	97.33	96.2
2.0	1230	4.87	24.33	48.66	98.1
3.0	615	2.43	12.16	24.33	99.0
4.0	410	1.62	8.11	16.22	99.3
6.0	246	0.97	4.87	9.73	99.6
8.0	176	0.70	3.48	6.95	99.7
10.0	137	0.54	2.70	5.41	99.8

(a) Power plant thermal efficiency assumed to be 40 percent. Heat duty is 3.81 billion BTU/hr and cooling tower temperature range is 11.1°C (20°F)

(b) Assumed heat transfer is 75 percent evaporative

(c) m^3/hr x 4.4 = gpm

(d) Based on the operation of a 65,150 m^3/hr "helper tower" in which warm water from the condenser(s) passes through the cooling tower and then directly to a receiving body.

PART B

THERMAL DISCHARGES

SECTION VIII

COST, ENERGY AND NON-WATER QUALITY ASPECT

Cost and Energy

The evaluation of the additional costs to be assessed against the power generated in a unit to which a helper or closed cooling system has been added are of prime importance to a utility. This provides a basis for determining the required rate increases. In addition, the capacity of a unit is reduced by the amount of power used in the cooling system plus any penalties that may be incurred by required shifting of unit operating parameters, primarily, the increase in the turbine exhaust pressure. This lost capacity must be replaced, either by new capacity, or operation of other units more intensively.

The cost of installation of cooling towers can be significantly higher at sites with adverse local conditions. Land with insufficient bearing strength would require piling, or use of mechanical draft towers instead of natural draft, or both. Conversely, in hilly terrain, extensive, and expensive, excavation into hard rock might be required. Even if only piping has to be excavated into rock, the cost is increased significantly. Reference 250 contains a detailed study of tower installations at such a site. Proximity of stations to earthquake faults means additional structural strength will be required, particularly in natural-draft towers. Towers in Florida and the Southeast require hurricane-resistant design. Other factors of a specific local nature at other sites will increase the cost of installation of cooling towers.

Addition of a cooling system to an existing plant will require breaking into existing structures, piping or tunnels. Suitability of existing structures used in the new system will have to be evaluated. Will the structures withstand the new pressures? Will it be easier to modify the condensers for increased pressures, and connect directly to them, or should the cooling system be connected at the present intake and outfall? These are questions that must be answered during design of the cooling system. The current layout, pump size, and location of intake and outfall structures will influence the required decisions.

The plant or unit will be shut down during the final period of installation when the new system is connected to the unit. The unit's generating capacity is lost during this period. In some cases the connections can be made during the annual scheduled overhaul. In other cases extended downtime may be required, maybe as much as three or four months. Costs would vary accordingly. The dollar value of these costs will vary from plant to plant.

The economic analysis of adding a supplemental cooling system to an existing unit consists of evaluating the costs of the following:

1. Installing the cooling system

2. Operating and maintenance costs of cooling systems

3. Providing additional generation capacity to replace power used or capacity lost

4. Operating and maintenance costs for replacement capacity

5. Additional cost of generation of remaining power due to a decrease in plant heat rate

Once these individual costs are determined, the total cost for the addition of a cooling system to an existing plant can be developed.

There are a number of methods in which the costs can be evaluated. These methods include annual costs, present worth, and capitalized cost.

Probably the most popular method of comparing investment alternatives for return on capital is the present worth method. The result of this type of analysis, and the capitalized cost method, is a dollar value for each alternative.

In this study, the interest is primarily in incremental costs, i.e., how many mills/kwh will the addition of a cooling system add to the cost of generation of each kwh? Since generation costs are normally expressed in mills per kilowatt hour, this was chosen as the cost basis for the addition of cooling systems. This cost was developed using the method of annual costs. The additional costs for the year were totaled and divided by the power generated to give an additional generation cost.

The capital investment involved in the addition of a new cooling system to a once-through plant can be split into two parts. The first is the installed cost of the tower and its necessary auxiliaries. These include new pumps, controls, power system, motor starters, and modifications to the existing condenser and piping system. The second part is the capital cost of the replacement generation capability. It is normally assumed that gas turbine units will be installed to provide the power to replace that no longer available due to installation of the cooling system. Once these costs have been determined, the annual cost is determined by use of the fixed charge rate. The fixed charge rate is a percentage, which when multiplied by the capital investment, gives the annual expenses incurred for the capital invested. Included in the fixed charge rate are interest on this capital, depreciation or amortization, taxes, and insurance. The actual fixed charge rates vary for each utility, but generally they average around 15% for investor-owned utilities. The fixed charge rate for publicly-owned utilities is normally several percent lower, with a 11% rate corresponding to the 15% for the investor-owned utility.

Of the four items included in the fixed charge rate, interest on the capital and depreciation or amortization account for the largest portion of the total. Interest on the capital varies with the current cost of money. Depreciation or amortization rates depend primarily on the life of the equipment to be built. An installation with a life of 25 years would be depreciated at 4%, while an installation with a life of 5 years would be depreciated at 20%.

When the complete plant is built at the same time, one rate is normally used to cover the entire installation. When adding a cooling system onto an existing unit, the period over which the cooling system is depreciated is the remaining life of the unit, not the life of the cooling system. Whether the cooling system will have any salvage value when the unit is shut down depends on the location and type of system used. Obviously, if the cooling system can be switched to another unit, it will have salvage value. For evaporative type towers, switching to another unit is generally not possible, and the tower will therefore have no salvage value. It will usually be uneconomical to move the tower due to the high construction costs involved. Powered spray modules will have salvage value, as they could be moved to other sites. If the cooling system will have a salvage value when the unit is retired, the amount upon which the depreciation is figured is the difference between the installed cost and the salvage value.

The operating and maintenance costs for a cooling system include the incremental power required by the pumps and fans (if mechanical draft is used), maintenance and annual overhaul labor and parts and associated overhead. Both the pumps and fans are low maintenance items, so the major cost is the energy to operate the system. One cooling tower manufacturer gives a figure of about $200 per year per fan cell as a tower maintenance cost. The circulating pumps would normally be overhauled once a year, which is a two week job on the average.

The amount of replacement generation capacity required is determined by adding the capacity penalty on the unit due to increased turbine backpressures to the power required by the cooling system. The unit capacity rating is normally given for a stated steam inlet condition and flow, and corresponding turbine exhaust pressure. If the cooling system can be added without changing the turbine exhaust pressure, there is no backpressure penalty. However, if the turbine exhaust pressure is increased, which normally occurs with a closed cooling system, the output of the unit is decreased by up to several percent, depending on the increase in turbine backpressure. Turbine manufacturers supply the curves necessary to determine this decrease in capacity with the turbine. The backpressure cannot be increased without limit, without necessitating redesigns of the turbine. For current condensing turbines, the maximum turbine exhaust pressures are 17 to 18.5 kN/sq m(5.0 to 5.5 in. of Hg abs). The limiting factor is the design of the last stages in the turbine. Once the amount of replacement capacity is determined, its cost can be calculated. If new capacity is installed, it would be completely separate from the unit, and would be depreciated independently of the unit for which the capacity was required.

The operating cost of this replacement power must be charged against the cooling system. The total operating cost would depend upon how many hours a year the additional generation was required. Throughout most of the United States, peak loads come during the summer months. Thus the replacement power would probably only be required during the summer. The remainder of the year, the units with backfitted cooling systems should be capable of handling the demand, even at the reduced capacity. The annual operating hours for which replacement power would be required and the associated cost would depend on the particular utility involved.

Associated with any capacity penalty is an increase in unit heat rate. The Joules (Btu) heat input to the unit is changed by adding the cooling system, but less power is generated due to the higher turbine exhaust pressure. This means that more Joules (Btu) are being used per Kwhr generated. Again, by making use of the turbine curve, the corresponding magnitude of the change in generation cost can be determined. Here again, the penalty will apply only part of the year. Only when the climatic conditions are such that the design turbine exhaust pressure is exceeded will this increased generation cost exist. Furthermore, the operation of the fans in mechanical draft towers need not be continuous throughout the year. Figure B-VIII-1 is an example of how the net power output of a unit can be optimized by reducing fan power. This is again dependent on the specific unit in question.

Once the annual costs for the above items have been determined, they can be totaled to give an annual cost for the addition of the cooling system for the unit. The total generation expected to be delivered to the bus bar is then determined, and the additional generation cost due to addition of the cooling system can then be determined directly.

Cost Data - Plant Visits

Cost data were obtained from the U.S. steam electric generating plants which were visited during the course of this study. The utilities involved were very helpful, with seventeen providing the requested information.

Nuclear plants and all three types of fossil-fueled plants (coal, oil, and gas) were visited. The size of the plants visited ranged from 28 Mw to the largest in the country at approximately 2,500 Mw. One plant had a unit constructed in 1924. In the remaining plants, all units were constructed after 1952, with 12 plants being constructed after 1960. Of the total number of plants visited, 5 were nuclear. Seven of the plants had once-through cooling systems, the remaining were on, or in the process of installing, closed or helper cooling systems.

The types of closed systems involved were mechanical and natural draft cooling towers, spray canals, and man-made cooling ponds. One of the two helper systems inspected utilized natural draft cooling towers, the other spray modules in the discharge canal.

Two types of information were requested, the first involved the physical description of the plant and its operation. The second was concerned with the cost of the plant, and the cooling system in particular. In addition, by visiting

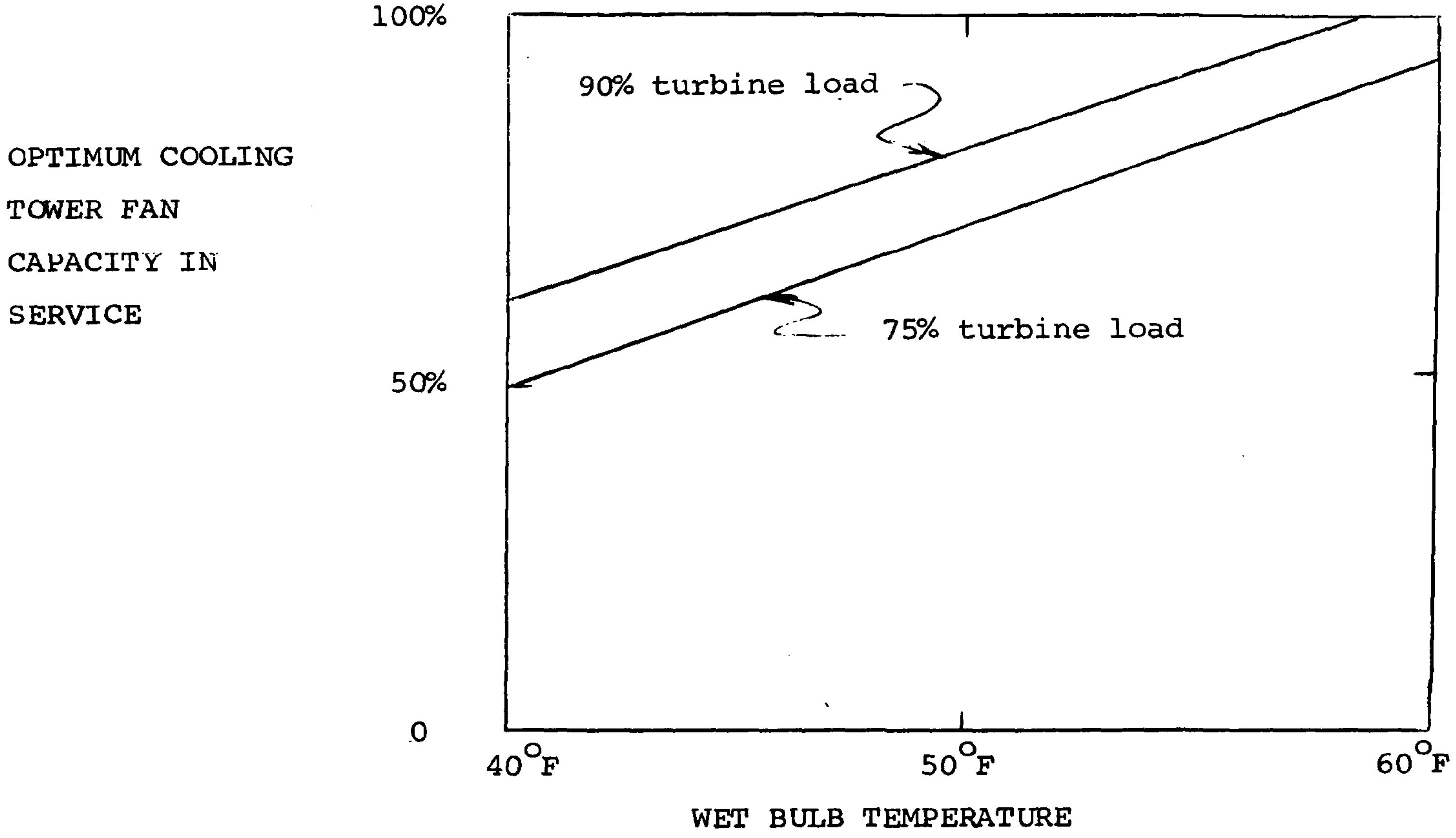

Figure B-VIII-1

EXAMPLE OF OPTIMIZATION OF NET UNIT POWER OUTPUT BY REDUCTION OF COOLING TOWER FANS[362] plants throughout the country, a great deal of information about regional problems and their solutions was collected.

A compilation of the cost data is shown in Table B-VIII-1. Probably the most important feature of this table is the great variation of costs involved. The land for plant No. 5105, a 1,157 Mw station, cost $172,000. The land at plant No. 0610, for a 750 Mw unit, cost $3,335,000, most of which was for a spray canal. In the table, the unit cost ($/kw) varies from a low of $68/kw to a high of $387/kw, with the higher values being those for the nuclear plants. The costs also vary with year of installation, with the older units having lower costs. The highest unit cost for a fossil-fueled plant is plant No. 2527 at $155/kw, for a 28 Mw plant. Larger plants tend to have lower unit costs. Plant No. 2525 at 1,165 Mw and a unit cost of $142/kw, seems to be an exception.

Operating and maintenance cost data for cooling systems are sketchy. In general, operating and maintenance costs appear to be a small part of the total operating cost for a station. In only one case was the reported operation and maintenance cost of the cooling system greater than 1% of the capital cost of the cooling system (Plant no. 3626). Energy required to operate the cooling systems, as reported, was 2% or less of the rated station capacity. Loss in capacity due to higher turbine exhaust pressures varied from 0.4% to 2.5%.

Of the five plants reporting increases in heat rate, three reported increases of 105 kJ/kwh (100 Btu/kwh) (roughly 1% of gross plant heat rate) or greater. When a specific plant is considered for a cooling system other than once-through, the plant cooling system design is normally optimized. This means some increase in turbine exhaust pressure, and consequently higher circulating water temperatures. This permits use of smaller cooling towers, and the savings realized on smaller towers more than offset the increase in costs due to the higher turbine exhaust pressure. Thus part of the heat rate increase is intentional, and results in lower overall costs.

The last two columns of the table describe the cooling system currently in use or being installed and the reason for its installation. Stations employing different types of closed cooling systems were included in the plants visited. In the table, a lake is differentiated from a cooling pond in that the lake in question was created by damming a stream in which the water rights did not belong to the power

TABLE B-VIII-1
COOLING WATER SYSTEMS - COST DATA
PLANTS VISITED

Plant ID	Type of Fuel	Capacity Mw	Plant Cost Data Date of Const.	Land $ (1000)	Structure $ (1000)	Equip. $ (1000)	Total Capital Cost $ (1000)	Unit Cost $/kw	Cooling System Cost Date of Const.	Land $ (1000)	Structure $ (1000)	Equip. $ (1000)	Total Capital Cost $(1000)	% of Plant Cost	Operating & Main. Cost $(1000)	Energy Cost Cooling System Energy Requirements	Increased Heat Rate Btu/kwh	Loss of Capacity Mw	Type of Cooling System	When Installed in Station
06[illegible]0	NUCLEAR	[illegible]16	1969-7[illegible]	-	-	-	355,000	387	1969-71	111	13,021	205	13,337	3.76	-	-	-		Natural Draft Wet Tower	Original Design
1201	OIL & GAS	139.8	1956-59	-	1960	12130	14,090	88.06	1956-59	-	316	825	1,141	8.1	11	-	-	-	Once Through Flow	Original Design 1 unit
1201	OIL & GAS	792	1969-72	1958	26000	85000	112,958	134.8	1969-72	1544	6,350	4,045	11,939	10.6	13	-	89	6-8	Cooling Pond	Original Design 2 units
5105	OIL	1157	1958-69	172	8638	116255	125,065	110.29	1970-71	109	1,082	1,349	2,540	-	-	-	-	-	Helper Spray Canal	Backfitted to meet stream stds 3 units
2525	OIL	1165	1961-69	605	20915	138127	159,648	142	1971-74				8,000			4MW	31	4	Helper Spray Canal Closed Spray Canal	Bckfttd to meet Str Stds (3units) Orig.Des. (1unit)
0801	COAL & GAS	300	1924-64	408	5858	29288	35,554	118.5	1924-64	(3)	1,820	261	2,081		7.04	-	-	-	Cooling Ponds (three)	Original Design
1209	COAL & GAS	820	1964-67	2213			59,175	68.5	1964-67	(3)	1, 62	2,146	3,908	4.5	10	-	-	-	Once Through Flow	Original Design (to be added to cooling canal)
1209	NUCLEAR	1486	1967-73				252,381	170.0	1971-74				37,858						Cooling Canal	Backfitted to close system
2612	NUCLEAR	700	1966-70	2393	37735	106856	146,984	210	1972-74				19,600			14MW	100	9	Mechanical Draft Wet Tower	Bckfttd to close cooling system
4217	COAL	1640	1965-68	3692	19502	158783	181,977	105	1965-68				15,750		36				Natural Draft Wet Tower	Original Design
3713	COAL	2137	1962-70	781	30163	174913	205,857	102.9		(2) 11524	(2) 25,[illegible]17	(2) 16,243	(2) 53,284						Cooling Lake	Original Design
3626	COAL	290	1952-55	69.58	4609	18511	23,190	153.12	1952-55		[illegible]58	585	844	3.67	48.5				Once Through Flow	Original Design
1723	NUCLEAR	1618	1966-72	1062	34833	110542	146,437	118					23,500	16.0		28.5	267	41.4	Spray Canal *(in process)*	Bckfttd to close *cooling system*
2512	OIL	542.5	1963-68	236	7994	55283	63,513	117	1963-68	20	[illegible]68	568	856	1.35					Once Through Flow (seawater)	Original Design
3115	*OIL & GAS*	644.7	1954	844	13806	71233	85,883	143					4818	8.03	4.632				Once Through Flow	Original Design
[illegible]117	NUCLEAR	457	1967-73	213	165480		165,693	344											Once Through Flow	Original Design
2527	OIL	28	1964-66	45	1072	3283	4,400	155											Once Through Flow	Original Design
0610	OIL & GAS	750	1968-72	3335	4036	97681	105,052	143	1971-72	2496		6975	9471	9					Spray Canal	Change from once through during constr.
2119	COAL	2534	1969	-	-	-	(1) 125,000	109	1969	-	-	-	8036	-	-	12	156	42	Nat.Drft.Wet Twr Hlpr&Closed Modes	Bckfttd on 2 units Orig.Des. 1 unit

(1) for Unit 3 only

(2) Only fraction of this cost allocatable to station 3713, breakdown not given in data

(3) Not given included in plant cost

company. In a cooling pond the water rights belong to the utility involved.

The last column designates whether the current cooling system is the original design or has been backfitted. Of the twenty stations visited, six are backfitted. Two of the stations visited were backfitting for the second time to meet increasingly stringent stream water quality standards. Several of the plants backfitting with closed systems are doing so as a result of legal action. In these cases the trend has been to go to a closed system. The necessity of getting additional generating capacity "on line" has been an important factor in determining the course of action taken.

It was evident from the visits that the spray canal with the powered spray modules is used primarily as a helper system to cool the circulating water to meet stream standards. This technology is relatively new, and some ancilliary problems remain to be solved before this technology becomes sufficiently reliable for extensive utility use.

Cost Studies for Specific Plants

Preliminary studies [464], [465] have been completed to indicate the feasibility, cost, and time required for construction of facilities to bring Pacific Gas and Electric Company's Moss Landing and Pittsburgh power plants into compliance with EPA's proposed effluent guidelines and standards for steam electric power plants (Federal Register March 4, 1974). All units at both plants would have been required to retrofit closed-cycle cooling systems by the proposed effluent limitations on heat.

Generating units at Moss Landing are as follows:

Unit No.	Capacity, Mw	Utilization	Initial Service Year
1	114	Peaking	1950
2	113	Peaking	1950
3	115	Peaking	1952
4	122	Cyclic	1952
5	122	Cyclic	1952
6	750	Baseload	1968
7	750	Baseload	1968

All units are fossil-fueled.

Conclusions of the study are as follows. It was shown that wet mechanical draft saltwater cooling towers could be retrofit to the Moss Landing Power Plant without the production of prohibitively high turbine backpressures for most of the anticipated operation. It should be noted that installation of these cooling towers would require the acquisition of additional property. The plant site property currently owned by PG&E is not adequate for the placement of the cooling towers required. The area selected for the installation of cooling towers is not well suited to the existing plant because of the length of the circulating water lines. This area is well suited, however, in terms of its effect on plant operation because the cooling tower plume would be carried away from the plant for most periods of operation. The increase in any operating cost of the units at the Moss Landing Power Plant would be consistent with the increase normally associated with the addition of cooling towers. The capital costs of these cooling towers and the associated equipment are higher than normal, which is usually the case with retrofit designs. Special considerations or design problems particular to this plant (i.e., the long circulating water lines required) induce even higher capital costs. The overall capital costs are estimated to be $28,186,000 at current prices (approximately $14/kilowatt). Allowance for engineering, taxes, and interest during construction, etc., and providing for reasonable contingency, increase these costs to $42,520,000 or $21/kilowatt. One of the largest cost items is the escalation, for serious inflation can be anticipated during the intervening years. The final escalated costs are $63,260,000 or $31/kilowatt.

Generating units at Pittsburg are as follows:

Unit No.	Capacity, Mw	Utilization	Initial Service Year
1	160	Cyclic	1956
2	170	Cyclic	1956
3	160	Cyclic	1956
4	170	Cyclic	1956
5	330	Baseload	1961
6	330	Baseload	1961
7	740	Baseload	1966

All units are fossil-fueled.

Conclusions of the study are as follows. It has been shown that wet mechanical draft cooling towers could be fitted to the Pittsburg Power Plant without the acquisition of additional land, and without the production of prohibitively high turbine backpressures for most of the anticipated operation. It should be noted, however, that the available land is nct well suited for towers because of its location with respect to the plant and that no other suitable lands are available because of other facilities and nearby residential patterns. The annual operating costs of the units at the Pittsburg Power Plant would be increased by a normal amount due to the addition of cooling towers, but the capital costs of these cooling towers and the associated equipment are abnormally high. Higher-than-normal capital costs are always associated with retrofit designs. Special considerations at this site, such as the length of the circulating water lines, result in capital cost of approximately $32 million at current prices (approximately $24/kw). Allowance for engineering, interest during construction, taxes, etc., and providing for a reasonable contingency increase this cost to approximately $49 million or $37/kw. One of the largest cost items, however, is escalation, for serious inflation can be anticipated during the intervening years. The final escalated cost is over $75 million or $57/kw.

A number of problems were encountered in the layout and preliminary design of the mechanical draft cooling system for the Pittsburg Power Plant. Basically, most of these problems can be attributed to the lack of space at an appropriate loaction for the layout of the cooling towers systems. These problems include:

- Distance and routing of the circulating water lines to the cooling towers.
- Access to the existing pumphouse.
- Placement of the towers with respect to downwind effects on the plant and switchyard.
- Placement of the towers with respect ot the subsurface conditions encountered in the foundation design.

There is adequate space on the property owned by PG&E for the cooling towers required for Units 1-6, as well as for towers for a proposed Unit 8 and for towers for replacement of the spray canal of Unit 7 should this replacement be desired. All of these towers would fit in the available area with sufficient spacing to minimize the mutual interference caused by placing such a large number of towers in one location. The major problem is that this space is a considerable distance from the plant itself, especially from Units 1-6. In addition, layout of the existing equipment and facilities in the area between the plant and the available space for locating the towers was made without any allowance for the later addition of closed-cycle cooling towers. Thus, the routing of circulating water lines would be extremely long, difficult to construct, and expensive.

When cooling towers are retrofitted to existing stations based on once-through cooling, certain difficulties are normally encountered. Problems associated with the interface between the existing circulating water system and the new equipment required for the cooling towers vary considerably from plant to plant. In the case of the Pittsburg Power Plant, access to the circulating water pumphouse has proven to be extremely difficult. Construction of offshore diking or sheet piling jetties might resolve this problem. However, this study has assumed that such construction would not be allowed. Therefore, construction of a new forebay behind the existing pumphouse would be required. This construction would prove to be extremely slow, inefficient, and costly because of the difficulty in avoiding damage to the surrounding structures. The only available space for the installation of cooling towers on PG&E property at the Pittsburg Power Plant is near the existing spray canal to the west of the plant. This location is not good with respect to the power plant operations because prevailing winds would carry the tower plume back over the plant and switchyard during much of the year. Although damage due to drift is expected to be considerably less than past experience because of the improved performance of cooling tower drift eliminators, the highly humid plume in the transmission corridor and switchyard area is still likely to cause some operating difficulties. The space available for the cooling towers is in an area of very poor soil condition and high groundwater. The porous nature of the peat soil causes the water table to be frequently at or near the surface. Special designs to prevent flotation and special designs for foundation in this type of peat material would be required, leading to extra costs.[465]

Sargent and Lundy [447] presented a summary of previous estimates they had made of the cost of backfitting some of their clients' units. The summary, shown in Table B-VIII-2, also describes the cost influencing items for each of the 13 plants covered.

A preliminary study [232] has been completed to assess the feasibility of backfitting closed-cycle cooling system with natural draft cooling towers at two TVA powerplants. Plant No. 4704 has four units with a total capacity of 823 Mw, has

Table B-VIII-2

Estimated Costs of Typical Installations of Backfitting Closed Cycle Cooling Systems to Once Thru Cycle Plants

(Estimated Costs Are Adjusted to Mid-1973 Levels)

STATION	NO. OF UNITS	TOTAL MW	TYPE FUEL	NO. & TYPE TOWERS	TOTAL NO. CELLS OR DIMENSIONS	STATION FLOW GPM	% OF FLOW TO TOWERS	BACKFIT COST $/KW	DESCRIPTION OF COST INFLUENCING ITEMS
1	4	1,161	Coal	3-M.D.	27	900,000	66%	$20.50	CRIB HOUSE ALTERATIONS AND EARTH WORK FOR CIRCULATING WATER AND BYPASS PIPING.
2	2	1,160	Coal	3-M.D.	27	916,000	66%	$14.37	COST OF CIRCULATING WATER PIPING FOR COOLING TOWERS AND EARTH FILL IN INTAKE CHANNEL.
3	4	905	Coal	3-M.D.	30	720,000	100%	$18.21	COFFERDAM, EARTH FILL, AND RIP RAP SLOPES REQUIRED IN COOLING TOWER AREA.
4	4	904	Coal	4-M.D.	40	946,000	100%	$34.68	EXTENSIVE COFFERDAM WORK AND EARTH FILL FOR COOLING TOWER AREA REQUIRED.
5	4	630	Oil	Hybrid	213'H x 475'Dia.	600,000	66%	$30.58	TUNNELING BELOW SANITARY DISTRICT SEWER, CITY SEWER, AND RAILROAD TRACKS.
6	2	432	Coal	2-M.D.	12	390,000	66%	$17.78	COST OF CIRCULATING WATER PIPING FOR COOLING TOWERS.
7	4	146	Coal	1-M.D.	5	95,600	66%	$31.90	COST OF COOLING TOWER INSTALLATION FOR LOW GENERATING OUTPUT.
8	1	107	Coal	1-M.P.	4	110,000	100%	$37.62	COST OF COOLING TOWER INSTALLATION FOR ONLY 1 UNIT OF GENERATING OUTPUT.
9	2	2,260	Nuclear	3 Hybrid	250'H x 390'Dia.	1,463,000	100%	$36.65	MODIFICATION OF CIRCULATING WATER AND SERVICE WATER SYSTEMS AROUND THE PLANT SITE.
10	4	905	Coal	1-N.D.	500'H x 500'Dia.	720,000	100%	$24.98	COFFERDAM, EARTH FILL, AND RIP RAP SLOPES REQUIRED IN COOLING TOWER AREA.
11	4	904	Coal	2-N.D.	450'H x 450'Dia.	946,000	100%	$49.69	EXTENSIVE COFFERDAM WORK AND EARTH FILL FOR COOLING TOWER AREA REQUIRED.
12	3	649	Coal	1-N.D.	370'H x 440'Dia.	570,000	66%	$18.09	TUNNELING BELOW CITY STREET INTO ROCK STRATA AND CONCRETE LINE THE ROCK SURFACE.
13	2	524	Coal	1-N.D.	350'H x 350'Dia.	376,000	66%	$27.95	COST OF CIRCULATING WATER TUNNELS AND VERTICAL SHAFTS.

a capacity factor between 0.2 and 0.6, and will have 12 years useful service life after 1983. Plant No. 0112 has eight units with a total capacity of 1978 Mw. Units 1-6 have a capacity factor between 0.2 and 0.6, and a useful life of 9 years after 1983. Units 7 and 8 have a capacity factor near 0.6 and a useful life of 29 years after 1977. The pertinent results of the study are as follows:

1) the conversions are feasible

2) cost for plant No. 4704 is $16.5 million;

cost for units 1-6 of plant No. 0112 is $18.6 million; and

cost for units 7, 8 of plant No. 0112 is $15.0 million

3) scheduled plant outage for any of the three is 2-3 months

In each case the cost of the tower including foundations is about 40% of the total cost, civil work (dikes, pump station, earthwork, etc.) about 40-50%, electrical work less than 3%, and mechanical work (pump, piping, etc.) about 10-15%.

Other Cost Estimates

Reference 385 collected estimates from other sources of the incremental costs of various alternative cooling systems compared to once-through fresh water systems for new plants. These cost estimates are summarized in Tables B-VIII-3 (fossil-fueled plants) and B-VIII-4 (nuclear plants). Also given in Reference 385 are estimates of the incremental costs of retrofit cooling systems for specific plants (See Table B-VIII-5) and new cooling systems for specific plants (See Table B-VIII-6).

Reference 385 estimated the effect of salinity on cooling tower costs. See Figure B-VIII-1a.

Reference 389 collected data on the capital costs of cooling ponds. See Table B-VIII-7. The cost of the cooling system as a percentage of total plant cost varied from 1.35% for a once-through system to 9% for a spray canal system. The costs depend a great deal on local conditions. In addition to varying land costs, foundation problems vary as well as length of intake and discharge channels, etc. Of the data collected, costs for cooling systems averaged less than 10% of the plant cost.

Table B-VIII-3

COMPARATIVE COST ESTIMATES OF NEW NUCLEAR-FUELED PLANT COOLING SYSTEMS 385

(Cost Estimates in Excess of Once-Through Fresh Water Systems)

	**WOODSON		**ORNL		**ROSSIE		JAMISON & **ADKINS		OLESON & BOYLE		**BATTELLE		FRANKLIN **INSTITUTE		**FWQA		**AEC	
	$ kW	mills kWh	$ kW	mills kWh	$ kW	mills kWh	$ kW	mills kWh	$ kW	mills kWh	$ kW	mills kWh	$ kW	mills kWh	$ kW	mills kWh	$ kW	mills kWh
Cooling Pond	3.4	0.07	5.6				3.4-4.5			0.11	5.9	0.17	6.3			0.02-0.07		
Spray Canal																		
Wet Towers																		
Mechanical Draft	4.7	0.10	11.9(a)	0.02			5.6-6.7			0.22(a)	7.0	0.37	6.9			0.10-0.17		
Natural Draft	10.6	0.22	14.3	0.27			6.7-9.0				12.8	0.43	9.5			0.17-0.26		
Dry Towers																		
Mechanical Draft	31.0	0.96	59.5(a)	1.37	25.8		25.8			0.90(a)	24.1	0.95	25.2				33.4- 34.3	0.87- 1.25
Natural Draft	61.4	1.57	71.4	1.57	30.2		28.0- 30.2				37.3	1.10					42.2	0.92- 1.32
Once-Through Salt											6.6	0.14						
Unit Capacity	800 MW_e		Not Available		800 MW_e		600 MW_e and larger		1132 MW_e		1000 MW_e		1000 MW_e		1000 MW_e		860-928 MW_e	

* Expressed in 1973 dollars. The dollar base year for each study was inflated or deflated, depending on the base year of the study, using a 6% per year inflation rate.

** Includes capability replacement costs.

(a) Costs for mechanical and natural draft towers.

Table B-VIII- 4

COMPARATIVE COST ESTIMATES OF NEW FOSSIL-FUELED PLANT COOLING SYSTEMS* 385

(Cost Estimates in Excess of Once-Through Fresh Water Systems)

	**WOODSON		**ORNL		**ROSSIE		JAMISON & **ADKINS		FRANKLIN **INSTITUTE		**FWQA	
	$/KW	mills/kWh	$/kW	mills/kWh	$/kW	mills/kWh	$/kW	mills/kWh	$/kW	mills/kWh	$/kW	mills/kWh
Cooling Pond	2.6	0.07	3.6- 6.0				2.2- 3.6		4.4		1.9- 3.0	0.01- 0.05
Spray Canal											3.8- 4.0	0.06- 0.08
Wet Towers												
Mechanical Draft	2.8	0.09	8.3[a]	0.05		1.12x	3.6- 6.0		3.8		4.2- 4.5	0.10- 0.14
Natural Draft	6.2	0.16	17.9	0.24			4.5- 6.7		5.7		8.1- 8.2	0.17- 0.26
Dry Towers												
Mechanical Draft	17.6	0.76	41.7-	1.13	19.0	1.12x+ 0.54	17.9- 19.0		20.2		22.6- 23.0	0.55- 0.83
Natural Draft	37.3	1.10	59.5	1.42	22.4		20.2- 23.5				24.8- 25.0	0.51- 0.76
Unit Capacity	800 MW_e		Not Available		600 MW_e		600 MW_e and larger		1000 MW_e		1000 MW_e	

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* Expressed in 1973 dollars. The dollar base year for each study was inflated or deflated, depending on the base year of the study, using a 6% per year inflation rate.

** Includes capability replacement costs.

(a) Costs for mechanical and natural draft towers.

Table B-VIII-5

COST ESTIMATES OF RETROFITTED PLANT COOLING SYSTEMS FOR SPECIFIC GENERATING STATIONS 385

(Cost Estimates in Excess of Once-Through Cooling System-1973 Dollar Value)

Nuclear

Plant	Size-MW	Cooling System Evaluated	Capacity Factor	Cost $/kW	Cost mills/kWh[5]
San Onofre 01	1-450	Diffuser	80%	15[1]	0.48
	1-450	Mechanical Draft Tower Saltwater-Open Cycle	80%	26[1]	1.14
	1-450	Mechanical Draft Tower Saltwater-Closed Cycle	80%	39[1]	1.17
	1-450	Mechanical Draft Tower Freshwater-Closed Cycle	80%	100[1]	2.22
	1-450	Spray Pond Cooling Saltwater-Open Cycle	80%	44[1]	1.34
Zion 1 & 2	2-1100	High Velocity Jet Dischg. Off-Shore Intake	72%	8[2]	0.20
	2-1100	Round Mechanical Draft Tower-Closed Cycle	72%	54[3]	1.53
	2-1100	Natural Draft Cooling Tower-Closed Cycle	72%	64[3]	1.73
	2-1100	Dry Mechanical Draft Cooling Tower-Closed Cycle	72%	208[3]	5.75
Quad-Cities 1 & 2	2-809	Diffuser	72%	6.3[4]	0.16
	2-809	Spray Canal Cooling Tower-Closed Cycle	72%	28[4]	0.78
	2-809	Mechanical Draft Tower Closed Cycle	72%	26[4]	0.72
	2-809	Natural Draft Cooling Tower-Closed Cycle	72%	36[4]	0.97
	2-809	Cooling Pond Closed Cycle	72%	30[4]	0.78
Dresden 2 & 3	2-809	Cooling Pond and Spray System-Closed Cycle	72%	21[4]	0.64

Fossil

Plant	Size-MW	Cooling System Evaluated	Capacity Factor	Cost $/kW	Cost mills/kWh[5]
Joliet (Old) Units 5 & 6	461	Natural Draft Cooling Towers-Closed Cycle	35%	30[4]	1.85
	461	Mechanical Draft Towers-Closed Cycle	35%	21[4]	1.36
	461	Cooling Pond Closed Cycle	35%	71[4]	4.67
	461	Spray Canal Closed Cycle	35%	60[4]	3.82
Joliet (New) Units 7 & 8	1,234	Natural Draft Cooling Towers-Closed Cycle	55%	23[4]	0.81
	1,234	Mechanical Draft Towers-Closed Cycle	55%	18[4]	0.64
	1,234	Spray Canal Closed Cycle	55%	23[4]	0.81

NOTES:

1. Base is considered as once-through single point ocean.
2. Base is considered as once-through on shore intake-discharge lake.
3. Base is considered as once-through with high velocity jet discharge off shore intake lake.
4. Base is considered as once-through river.
5. Includes investment, capability loss charges, and operating and maintenance costs.

Table B-VIII- 6

COST ESTIMATES OF NEW PLANT COOLING SYSTEMS FOR SPECIFIC GENERATING STATIONS[385]

(Cost Estimates in Excess of Once-Through Cooling Systems-1973 Dollar Value)

Plant	Size-MW	Cooling System Evaluated	Capacity Factor	Cost $/kW	Cost mills/kWh[3]
San Onofre 2&3	2-1140	Mechanical Draft Cooling Towers - Salt Water Closed Cycle	80%	23[1]	0.75
	2-1140	Mechanical Draft Cooling Towers - Salt Water Open Cycle	80%	32[1]	1.01
	2-1140	Multi-Point Diffuser	80%	6	0.17
Perry 1&2	2-1200	Natural Draft Cooling Towers - Fresh Water Closed Cycle	80%	11.3[2]	0.25
	2-1200	Mechanical Draft Cooling Towers - Fresh Water Closed Cycle	80%	15.1[2]	0.38
	2-1200	Spray Canal Cooling - Fresh Water Closed Cycle	80%	12.7[2]	0.58
Davis-Besse	1-872	Natural Draft Cooling Towers - Fresh Water Closed Cycle	80%	25.2[2]	0.62
	1-872	Mechanical Draft Cooling Towers - Fresh Water Open Cycle	80%	32.8[2]	0.81
		Spray Canal Cooling - Fresh Water Open Cycle	80%	15.6[2]	0.39

Notes: 1 - Base is considered as ocean-(deep intake - deep discharge)
2 - Base is considered as once-through lake
3 - Includes investment, capability losses, and operating and maintenance costs

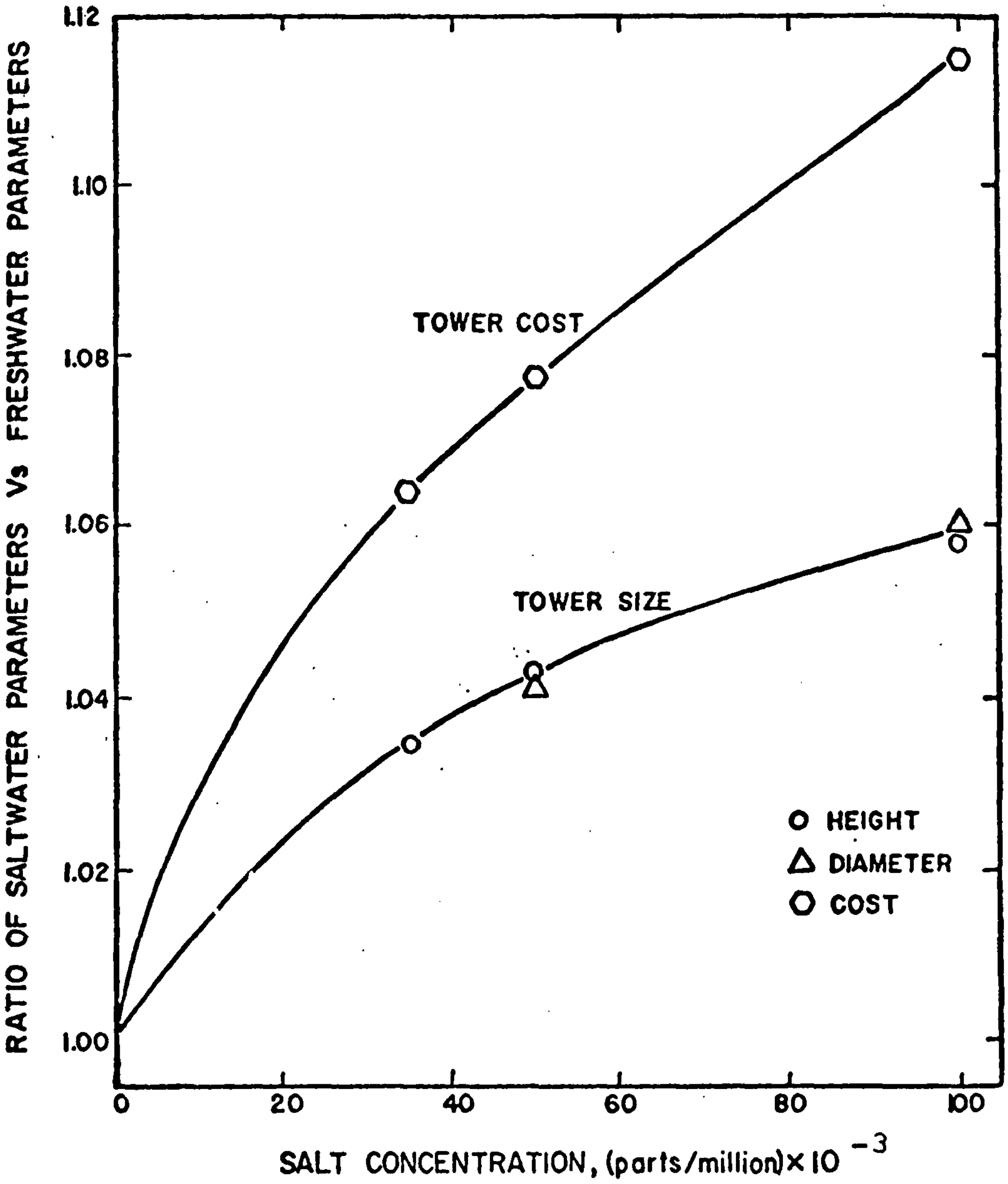


Figure B-VIII-1a Salinity Effects on Cooling Tower Size and Costs[385]

Table B-VIII-7

Capital Costs of Selected Cooling Ponds (c) 389

PLANT	1970 CAPACITY (Mw)	SURFACE AREA (ACRES)(b)	CAPITAL COST OF COOLING POND ($)	UNIT COST		COMMENTS
				$/Mw	$/ACRE	
H. B. ROBINSON	906	2145	4,800,000	5,298	2238	1971 Capacity
ROXBORO (a)	1067	3750	4,831,000	4,528	1288	
BRAUNIG	885	1250	4,717,000	5,330	3774	
KINCAID	1319	2400	3,819,000	2,895	1591	
MT. CREEK	990	2710	4,333,000	4,377	1599	
NORTH LAKE	709	800	3,555,000	5,014	4444	
BALDWIN (a)	584		3,000,000	5,137		
VALLEY	725	1000	918,209	1,266	918	
MT. STORM (a)	1140	1120	6,523,000	5,722	5824	

a Future expansion at site contemplated.

b One acre equals 4047 m^2.

c Covers land and land rights costs only.

Based on the FPC Form 67 data for the year 1970[233], the capital costs reported for once-through (fresh) cooling is $4.03 per kw, once-through (saline) is $4.63 per kw, cooling ponds is $5.43 per kw, and cooling towers is $6/25 per kw. The incremental cost shown of cooling towers over once-through systems is about $1.6 - $2.2 per kw.

Sargent and Lundy Engineers[448] estimated costs of mechanical and natural draft cooling towers compared to once-through cooling for new plants as shown in Table B-VIII-8. Incremental capital costs of mechanical draft cooling towers over the cost of once-through system capital costs are $3.09/kw for a 1150 Mw nuclear unit and $4.46/kw for a 550 Mw fossil-fired unit based on 1974 dollars.

Reference 368 presents nomographs which permit the estimation of cooling system performance and costs.

In general, it seems possible to distinguish three groups of economic factors that could affect the relative costs of open and closed cycle cooling systems. The first group consists of the cost elements of the plant cooling water system itself. These include the intake structure, screens, pumps, piping, condenser, discharge facilities, and water and wastewater treatment plant.

The second group of cost factors concerns itself with the limitations on the location of the plant imposed by the once-through cooling system. A once-through cooling system plant must be located at or near the level of the water supply. This frequently results in high costs for dewatering the site, and high foundation costs for piling or concrete mats to protect the plant against settlement, flotation during periods of high groundwater, or flooding. Even if a site has already been committed, there may be alternate locations on the site or alternate foundation arrangements and floor elevations which are less costly than those dictated by the limitations imposed by the once-trhough circulating water system.

The third group of cost factors apply only if the site has not been selected, and generally cnly to coal-fueled plants. These relate to the fact that it is generally more economical to transmit electricity than to ship coal and the location of the source of the fuel has a greater impact on economics of generating electricity than availability of sufficient quantity of water than once-trhough cooling. There are also cost savings which result from generally better foundation conditions and lower requirements for architectural and other aesthetic aspects. The magnitude of

Table B-VIII-8

Thermal Control Costs for New Plants [448]

Cooling System	Capital Cost, 1974 (exclusive of escalation, allowance for funds used during construction, or allowance for indirect costs	
	550 Mw Fossil-Fired	1150 Mw Nuclear
Once-through	$2,646,000	$10,052,000
Mechanical-draft cooling tower	5,096,000	13,599,000
Natural-draft cooling tower	8,047,000	17,458,000
Incremental (mechanical draft less once-through)	$2,450,000 ($4.46/kw)	$ 3,547,000 ($3.09/kw)

this factor may be approximated by the cost of shipping coal, which is of the order of $10 per ton for a haul of 250 miles. This is equivalent to 0.5¢ per lb. of coal or per kwh of electricity generated.

Costs Analyses

The initial part of this work consisted of preparing cost estimates for placing the various types of evaporative cooling in a number of hypothetical plants in various representative locations in the United States.

Four typical plants were chosen:

100 Mw fossil-fueled unit

300 Mw fossil-fueled unit

600 Mw fossil-fueled unit

1,000 Mw nuclear-fueled unit

Two condenser temperature rises were chosen, 6.7°C (12°F) and 11.1°C (20°F). These represent the lower and upper design averages in plants currently operating in the once-through mode, or plants that would be considered for backfitting with closed cooling systems. A turbine exhaust pressure of 8.45 kN/sq m (2.5 in. of Hg) abs. was chosen as being an average of the units in this group. This pressure, plus the climatic conditions, permitted design of a closed cooling system.

The four locations chosen for this analysis were Seattle, Washington (cool), Phoenix, Arizona (hot and dry), Richmond, Virginia (average), and Pensacola, Florida (hot and humid). The wet bulb temperatures used were those listed as being equaled or exceeded only 5% of the time, on the average during the four months of June through September.[52] This amounts to 110 hours for this period.

The necessary information was submitted to three cooling tower manufacturers and two powered spray module manufacturers for cost estimates. These conditions assumed 100% heat removal in the tower and no change to the generating unit, i.e., cooling water temperature was the same. Of the total of 32 separate plants resulting from the matrix of conditions, 20 were capable of being backfitted with mechanical draft cooling towers, and 16 with natural draft cooling towers. Use of natural draft towers in Phoenix were not practical due to low humidity.

One powered spray module manufacturer proposed systems for 28 of the 32 cases, while the other proposed for 16 of the 32 cases. The costs of the equipment only is shown in Table B-VIII-9. The mechanical draft tower (wood construction), and the natural draft tower (concrete construction), are the two types of cooling towers most widely used in this industry. These are considered available technology. Powered spray modules are being used for backfitting to reduce circulating water temperatures to meet stream standards. As such, they are available technology. At one major plant the powered spray modules are being installed in a closed system.

Table B-VIII-9 illustrates a number of points. The first is that under the conditions specified, natural draft cooling towers are considerably more expensive to buy than the other types. This is particularly true for smaller plant sizes in which the natural draft tower would not be expected to be competitive. However, operating costs are less, which makes their overall cost lower than the tower cost would seem to indicate. For mechanical draft towers, it appears that concrete construction is more expensive than wood by a factor of 1.4. The cost of all the systems, exclusive of the natural draft tower is about the same. Thus if mechanical towers are used as a technology to investigate the costs of their application, use of the other systems would result in similar costs. This leaves a number of options open to utilities for about the same cost. Each plant would have to be evaluated on an individual basis to determine the most economical system for that station. Cooling ponds were not covered in detail since their use is not dependent upon equipment supplied by a manufacturer. Their cost is almost entirely composed of land cost and the cost of the retrofit. This option is available for use and considered as a lower cost available technology for those plants where suitable land is available.

For the overall costs analysis, the additional cost (in mills/kwh) to install and operate a mechanical draft cooling tower as a function of the percent of heat removed from the circulating water is generally representative of the overall cost of the application of effluent heat reduction technology, due to general similarity of costs among available technologies. Due to the broad spectrum of unit sizes and conditions throughout the United States, the number of cases studied had to be strictly limited to provide a manageable number of analyses. The first restrictions were made on the basis of the categorization of the industry. Fossil-fueled plants only were considered, as these make up the bulk of existing facilities at present.

TABLE B-VIII- 9

COST OF COOLING SYSTEM EQUIPMENT

Unit Size (MW)	Unit Location	Circulating Water Rise (F)	Cost For System $(\$\ x\ 10^{-6})$					
			Mech. Draft Wood Constr.	Mech. Draft Concrete Contr.		Natural Draft	Powered Spray Module	
				Mfr. A	Mfr. B		Mfr. A	Mfr. B
100	Seattle	12	.400	.550		2.5	.380	.364
		20	.459	.648	.650	2.8	.532	.401
	Phoenix	12	.612	.857	.825		.684	.765
		20					1.596	
	Richmond	12	.567	.798	0.800	4.1	.684	.656
		20					1.293	
	Pensacola	12	.728	1.019	0.955	4.3	.836	
		20						
300	Seattle	12	1.050	1.442		3.9	1.064	.875
		20	1.195	1.665	1.490	4.7	1.293	1.130
	Phoenix	12	1.768	2.478	2.232		1.824	1.933
		20					4.180	
	Richmond	12	1.640	2.300	2.010	8.0	1.748	1.695
		20					3.345	
	Pensacola	12	2.025	2.835	2.530	8.3	2.05	
		20						
600	Seattle	12	1.815	2.491		5.5	1.748	1.531
		20	2.154	3.014	2.640	6.8	2.200	1.763
	Phoenix	12	3.102	4.332	3.825		3.118	3.390
		20					7.22	
	Richmond	12	2.648	3.705	3.525	14.6	2.965	2.984
		20					5.700	
	Pensacola	12	3.497	4.897	4.470	15.1	3.57	
		20						
1000	Seattle	12	4.275	5.867		10.1	4.180	3.255
		20	4.840	6.780	6.000	14.7	4.940	3.933
	Phoenix	12	7.281	10.191	9.050		7.380	8.070
		20					16.040	
	Richmond	12	6.765	9.465	8.250	30.8	6.920	6.984
		20					12.700	
	Pensacola	12	8.337	11.677	9.900	31.9	8.51	
		20						

The next break came on the basis of unit use. A statistical analysis of the plants reporting to FPC on Form 67 resulted in the statistics shown in Table B-VIII-10. Based on these figures, the figures shown in Table B-VIII-11 were used in the analysis. The only adjustment, other than rounding off, were made in the heat rate. These heat rates are based on total fuel burned and total kwh's generated during the year. Since by definition a base unit is operating at or near capacity most of the year, this heat rate is fairly representative of the actual heat rate while operating at near full capacity. The same is not true of the other two cases. The cyclic unit, operates for longer periods of time at lower loads, where efficiency is lower. This unit may act as spinning or standby reserve where the boiler is up to pressure, but little power is being generated. Thus the heat rate is higher than that actually existing when the plant is operating at near full capacity, the heat rate desired for this analysis. The cyclic unit heat rate was reduced to 12,000 kJ/kwh (11,500 Btu/kwh), considered to be more truly representative of the actual unit heat rate. The same factors influence the heat rate of the peaking unit, even to a greater degree. The heat rate of peaking units was reduced to 13,200 kJ/kwh (12,500 Btu/kwh) as being a more realistic figure. Note that when a unit is being held in a warm standby condition it is normally not connected to the circulating water system. Thus, most of the increased heat is discharged to the stack and not to the receiving water. Since the purpose of the analysis was to determine the range of costs involved in installing wet cooling towers on existing units, three wet bulb temperatures were chosen as the worst, near average and best wet bulb temperatures, for cooling tower design purposes, in the United States. The worst, or highest wet bulb temperature was 28°C (83°F). This was at the 1% level, exceeded only one percent of the time during June through September. An average chosen was 24°C (75°F), and the lowest summer wet bulb at the 1% level was 14°C (57°F).

The remaining factor was unit age, and this was taken into consideration as unit remaining life, assuming a unit life of 36 years. The median ages of the three age categories, 6, 18, and 30 years, were used. This gives a total of 27 cases, 3 types of units multiplied by 3 wet bulb temperatures multiplied by 3 ages.

Some additional information on the unit must be specified. The plant size chosen was 300 Mw. By using a 300 Mw unit, some idea of the magnitude of the various costs could be made. Since parameters and costs used varied linearly with unit size, the costs, in terms of mills/per kwh, will be

TABLE B-VIII-10
HYPOTHETICAL PLANT OPERATING PARAMETERS

Type of Unit	Hours Up per Year	Heat Rate		Capacity Factor	Bus Bar Cost mills/kwh
		kJ/kwh	Btu/kwh		
Base	7685	11,231	10,636	0.77	6.24
Cyclic	4475	13,192	12,493	0.44	8.35
Peaking	1155	16,677	15,793	0.09	12.50

TABLE B-VIII-11
REVISED PLANT OPERATION PARAMETERS

Type of Unit	Hours Up per Year	Heat Rate		Capacity Factor	Bus Bar Cost mills/kwh
		kJ/kwh	Btu/kwh		
Base	7690	11,088	10,500	0.77	6.34
Cyclic	4500	12,144	11,500	0.44	8.35
Peaking	1200	13,200	12,500	0.09	12.50

applicable to any unit for which the basic assumptions are valid and operating parameters fall within the range indicated. It was further assumed that operation of the unit at a turbine exhaust pressure of 8.45 kN/sq m (2.5 in. of Hg abs) would incur no operating penalty other than the power requirements of the tower and pumps. Any increase in pressure above this would result in both an additional capacity penalty and a fuel penalty.

A circulating water temperature rise of 16.7°C (30°F) was chosen as being the highest to be found in the units being considered for backfitting. Due to the restrictions on approach and cold water temperature to the condenser, this is the most restrictive set of temperature criteria for tower design. The other extreme of circulating water rise is about 6.7°C (12°F). For the same size plant, the cooling water flow would be increased by a factor of 2.5. This has a significant effect on tower cost, but the temperature criteria are much less restrictive. This permits, as will be explained later, modification of the cooling system to significantly reduce the cost for the case with a 6.7°C (12°F) temperature rise.

Two additional parameters were chosen, the first was a terminal temperature difference of 5.5°C (10°F) in the condenser. The second was to establish 6.7°C (12°F) as the minimum approach to be used in tower design. This value was determined through conferences with cooling tower manufacturers.

The above plant characteristics are summarized in Table B-VII-12.

A number of additional assumptions related to the economics of the utility industry were necessary to complete the analysis. Since the pumps required to circulate water through the cooling tower are not included in the cost of the tower, these were priced using a total dynamic head of 24 meters (80'), of this 24 meters (80'), 18 meters (60') was required in the tower, and the remaining 6 meters (20') was for pipe losses and additional lift required. Since most once-through condensers make use of the siphon effect to lower pumping requirements, the original pumps are low head, and would not be suitable for cooling tower service. There are a number of ways in which the cooling tower could be connected, but all include new pumps, either to handle the entire system or to be placed in series with current pumps. The cost of the pumps was estimated at $100/hp, and an overall pump-motor efficiency of 80% was assumed. The

TABLE B-VIII- 12
TYPICAL PLANT CHARACTERISTICS

Unit Size - 300 Mw
Unit Types - Base, Cyclic, and Peaking
Wet Bulb Temperatures - 83°F, 75°F, 57°F
Median Remaining Unit Life - 6, 18, and 30 years
Circulating Water Rise - 30°F (Upper Limit)
Condenser TTD - 10°F
Cooling Tower Approach - 12°F minimum

cost of connecting the cooling tower into the existing circulating water system is site dependent and is therefore extremely variable. Factors that influence the cost of the tower installation include the relative locations of tower and plant, the type of terrain and soil conditions, and the site, type and locations of connections that must be broken into. Indirect costs for engineering, legal, and contingencies must also be included.

Table B-VIII-1 shows the cost of installing the cooling systems at the plants visited during the study. The average value for retrofitted closed cooling systems was approximately $17/kw. For a 300 Mw unit, this amounts to approximately $5 million for the complete installation including tower, pumps, installation and indirect costs. The cost of the tower and pumps alone for this installation would be approximately $1.25 million. Therefore, the total installed cost is approximately 400% of the cost of the major equipment involved. The basis for this estimate of the costs of tower and pumps was a base-load unit installed at a location where the design wet bulb temperature was 75°F. The cost will vary for other wet bulb temperatures with a range of about $13/kw to $25/kw.

For the purposes of the economic analysis a markup of 300 percent above the the base cost of the major equipment items was allowed to cover the installation costs and indirect costs mentioned above. This allowance is considered to be conservative for most cases.

To determine the tower costs, the cost information on mechanical draft towers from Table B-VIII-9 was used to develop a linear relationship between the tower parameters (approach, range, flow, and wet bulb) and cost. The variation in cost was less than 5% at the 28°C (75°F) wet bulb temperatures, and averaged less than 15% for the 14°C (57°F) wet bulb temperature. Land cost was not included in the tower capital cost due to wide variation throughout the country.

Fan power requirements were also determined in a similar manner, with less than 10% variation. The operating cost of the towers was assumed to be primarily the cost of the electricity to run the fans and pumps, and was charged at the average rate for the particular type of unit, except in the case of the peaking unit. In this case the average power cost was 2.5 mills/kwh higher than the operating cost of replacement gas turbines, assumed to be 10 mills/kwh. Thus in this case, it was assumed that the power required to operate the tower cost 10 mills/kwh. Ten percent of the operating cost of the fans and pumps was added to cover maintenance and parts for this equipment.

Since there were three remaining life spans considered, and since the tower had essentially no salvage value, the cost of the tower had to be absorbed during the remaining plant life. To account for this, three fixed charge rates were used, one for each of the three remaining life spans as follows: 6 years - 30%, 18 years - 19%, and 30 years - 15%.

These are rates for investor-owned utilities; public utility rates would be lower.

It was assumed that the energy required by the cooling tower system was replaced with energy produced by a gas turbine. In addition, any capability loss due to operation at higher turbine exhaust pressures was replaced with gas turbine generating capacity. It was assumed that the installed cost of these gas turbines was $90/kw. 1970 costs are used throughout this analysis. Since the life of these units was independent of the unit whose power they were replacing, a 30 year life was assumed and the fixed charge rate was accordingly 15%. If base load capacity were used in place of turbines to replace the capability loss, the annual costs of replacement capacity would be less.

Any increase in turbine exhaust pressure results in a higher heat rate, and consequently a higher generation cost. The following changes in heat rate were assumed. They were taken from a typical curve for a turbine with initial steam conditions in the superheat region. Values used are shown in Table B-VIII-13.

This increase in generating cost was based on the average generating cost for the type of unit being considered. These factors and assumptions are summarized in Table B-VIII-14.

Several additional assumptions were made about each type of unit, base, cyclic, and peaking. These were mainly concerned with the number of hours the gas turbine would operate and the fuel penalty that would be assessed. Since the peak load normally comes in the summer months and this period is the critical one for tower operation, the penalties normally apply during this period. For the base units, it was assumed that they would operate under penalties equivalent to full penalty for one half of the average number of hours per year. Cyclic units were assumed to operate under full penalties for 2,000 hours per year. Since peaking units average 1,800 hours per the penalties

Table B-VIII- 13

ASSUMED INCREASE IN HEAT RATE COMPARED TO BASE HEAT RATE AS A FUNCTION OF THE TURBINE EXHAUST PRESSURE

Turbine Exhaust Pressure, in. Hg	Increase in Heat Rate, % of base
2.5	Base
3.0	0.4
3.5	0.8
4.0	1.4
4.5	2.0
5.0	2.8
5.5	3.6

Table B-VIII-14

COST ASSUMPTIONS

Pumps required for tower	$100/HP @ 80 ft of head, 80% overall efficiency
Tower cost	Interpolation from Table B-VIII-2
Fan power	Interpolation from Table B-VIII-2
Pump power	80 ft of head, 80% efficiency
Fan and pump operating cost	Electrical energy at average for type of unit, plus 20% for maintenance
Fixed charge rates	
6 yr remaining life	30%
18 yr remaining life	19%
30 yr remaining life	15%
Replacement power	Combustion gas turbines @ 90$/ kw and 10 mills/kwh
Replacement power fixed charge rate	15%
Fuel penalty	Assessed at cost of generation for type of unit considered except for peaking units, where cost is 10 mills/ kwh

would apply during the full 1,800 hours of operation. These values are considered near the maximum, and the actual values will vary from unit to unit. Shut down of the unit is required during the time required to connect the cooling tower into the existing circulating water system. The time required to make this connection will depend on the layout and accessibility of the existing cooling water system compments. It is estimated that the time required to perform this work will vary from 2 to 5 months, depending on these conditions, with an average time of 3 months. One month of this requirement can normally be scheduled to coincide with the annual maintenance period when the unit is down in any case. Therefore, additional cost will be incurred to supply the power normally generated by the unit for a period of two months. It is further assumed that shutdowns to allow these modifications to be made can be scheduled to coincide with periods of low system demand. Therefore, replacement power can be obtained by higher utilization of other equipment in the system rather than by wholesale import of power from other sources.

It may not be possible to have the tie-in coincide with scheduled maintenance outages in some cases. In some instances several units at a site may of necessity be taken out of service concurrently to accomplish the tie-ins.[463]

Replacement power for base-land units undergoing these modificiations will be supplied by operating cycling units more intensively. The utilities will incur additional operating costs because these units are typically less efficient than the base-loaded units. A differential energy cost of 3 mills/kwh was assumed to be representative of the increased operating costs of these types of units. The total costs associated with loss of the unit was obtained by multiplying the capacity of the unit by the number of hours affected, the units annual capacity factor and the differential operating cost. The decreased utilization of cycling and peaking units will generally allow them to be modified without incurring downtime costs as high as the base-load units. However for the purposes of consistancy of the analysis, similar penalties were assessed against these units as well.

In order to extend this cost to the remaining units of power production, the total cost was considered to be money borrowed at an annual interest rate of 8% compounded. This loan was then assumed to be repaid over the remaining life of the unit and the annual costs obtained were spread over the average annual generation.

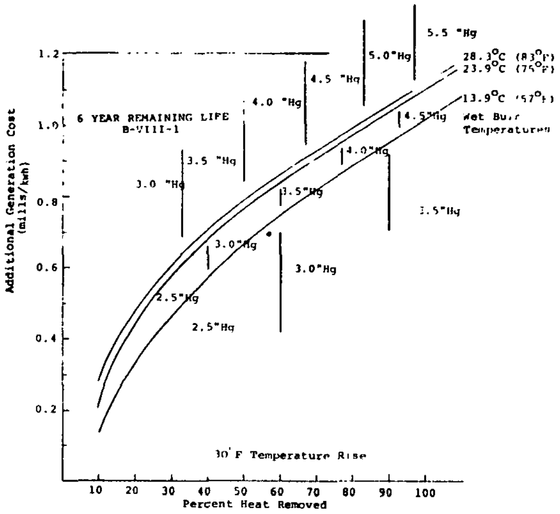
A sample calculation for a peaking unit with a 24°C (75°F) wet bulb design temperature, is shown in Table B-VIII-15. The procedure was to assume 8.45 kN/sq m (2.5 in. of Hg abs) turbine exhaust pressure with its corresponding 99°F hot water temperature. With a minimum approach of 6.7°C (12°F), the maximum range of the tower is 6.7°C (12°F) or the percentage of heat removed is 12/30 or 40%. Using a minimum range at 5.5°C (10°F) the % of water flow through a tower for heat removals below 40% were determined. The turbine exhaust pressure was then increased to 10.1 kN/sq m (3.0 in. of Hg abs), the maximum heat removal determined (60%) and conditions for removal of from 40% to 60% removal determined. The same procedure was used at 11.8, 13.5, and 15.2 kN/sq m (3.5, 4.0, and 4.5 in. of Hg abs) until 100% removal was obtained. The analysis then proceeded in an orderly fashion as shown in Table B-VIII-15. The other 26 cases were treated in a similar manner, and the result was a set of nine graphs showing the range of additional generation costs involved in backfitting the hypothetical 300 Mw unit with mechanical draft cooling towers. Since all factors were linear with size, these costs will be applicable to any size plant in which the basic assumptions are still applicable. Conversations with cooling tower manufacturers indicate that for mechanical draft towers only a small variation in cost would be expected in the range of units involved, including a 1 Mw plant. Pump costs may increase in the smaller size units.

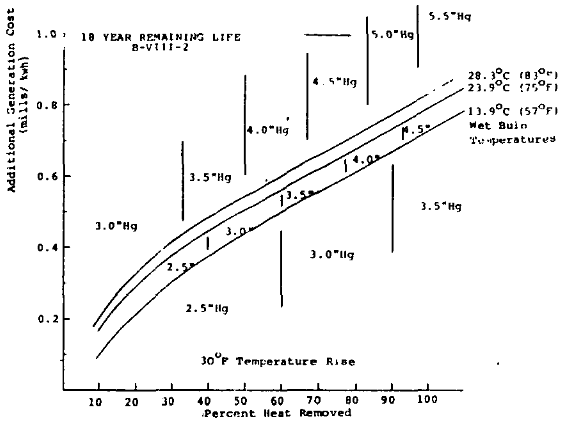
The first three graphs, Figures B-VIII-2, B-VIII-3, and B-VIII-4, cover base-load units. Additional generation costs ranged from a low of 0.60 mills/kwh at a 13.9°C (57°F) wet bulb temperature and 30 year remaining life to a high of 0.65 mills/kwh at a 28.3°C wet bulb temperature and 6 year remaining life. These are for 100% (actually about 98%) heat removal. As indicated on the graphs, it was necessary to increase turbine exhaust pressure in every case to achieve 100% heat removal within the limitations placed on the hypothetical unit. At an average generation cost of 6.24 mills/kwh, the maximum additional cost of 1.10 mills/kwh is an increase of about 17%, with the minimum for 100% heat removal of about 10%.

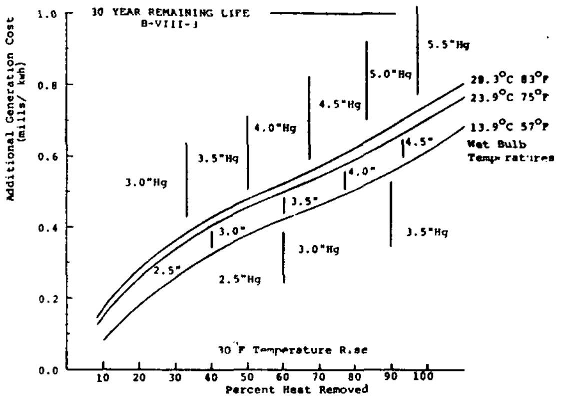
To evaluate the effect of circulating water rise on additional generation cost, additional calculations for a 6.7°C (12°F) circulating water rise were made for the 30 year and 18 year remaining life categories at a 23.9°C (75°F) wet bulb temperature. The 6.7°C (12°F) rise approximates the lowest value found in current plants. The results are shown in Figures B-VIII-5 and B-VIII-6. At heat removal fractions above 50%, costs are significantly higher.

TABLE B-VIII. 15
COOLING TOWER ECONOMIC ANALYSIS
(300 Mwe Unit, Peaking Service, Wet Bulb Temperature 75°F)

Turbine Exhaust Pressure in. Hg abs.	Percent of Heat Removal	Percent of Water thru Tower	Tower Range (°F)	Tower Approach (°F)	Tower Cost $	Pump Cost $	Total plus 25%	Annual Cost 6 Year Life	Annual Cost 18 Year Life	Annual Cost 30 Year Life	Annual Fan Operating Cost ($)	Annual Pump Operating Cost ($)	Total plus 10% for Main. ($)	Fan Power Mwe	Pump Power Mwe	Capacity Penalty Mwe	Total Penalty Mwe	Capital Cost of Gas Turbine $	Annual Cost 15% $	Operating Cost $	Fuel Penalty Cost $	Additional Generating Cost (mills/kwh) 6 Year Remaining Life	Additional Generating Cost (mills/kwh) 18 Year Remaining Life	Additional Generating Cost (mills/kwh) 30 Year Remaining Life
2.5	40	100	12	12	760,700	354,200	1,393,600	418,100	264,800	205,000	8,500	31,700	44,200	.7	2.6	0	3.3	301,500	45,200	40,200	0	2.98	2.14	1.84
	30	90	10	14	531,200	318,800	1,062,500	318,800	201,900	159,400	6,000	28,600	38,100	.5	2.4	0	2.9	259,200	38,900	34,600	0	2.34	1.70	1.47
	20	60	10	14	354,400	212,500	708,600	212,600	134,600	106,300	4,000	19,000	25,300	.3	1.6	0	1.9	171,900	25,800	22,900	0	1.56	1.13	.98
	10	30	10	14	176,800	106,300	353,800	106,100	67,200	53,100	2,000	9,500	12,600	.2	.8	0	1.0	85,500	12,800	11,400	0	.77	.56	.49
3.0	60	100	18	12	1,067,300	354,200	1,776,900	533,100	337,600	266,500	12,000	31,700	48,000	1.0	2.6	1.4	5.0	435,600	65,300	58,000	18,000	3.93	2.86	2.48
	50	100	15	15	749,400	354,200	1,379,500	413,800	262,100	207,000	8,400	31,700	44,100	.7	2.6	1.4	4.7	408,600	61,300	54,500	18,000	3.22	2.39	2.09
	40	95	13	17	561,200	336,500	1,122,100	336,600	213,200	168,300	6,200	31,700	41,700	.5	2.5	1.4	4.4	380,700	57,100	50,300	18,000	2.74	2.07	1.83
3.5	77	100	23	12	1,214,900	354,200	1,961,400	588,400	372,700	294,200	13,700	31,700	49,900	1.2	2.6	2.7	6.5	556,200	83,400	74,200	35,800	4.80	3.62	3.20
	70	100	21	14	965,100	354,200	1,649,100	494,700	313,300	247,400	10,800	31,700	46,800	.9	2.6	2.7	6.2	534,600	80,200	71,300	35,800	3.96	2.98	2.62
	60	100	18	17	760,700	354,200	1,393,600	418,100	264,800	209,000	8,500	31,700	44,200	.7	2.6	2.7	6.0	517,500	77,600	69,000	35,800	3.50	2.67	2.37
4.0	93	100	28	12	1,351,100	354,200	2,131,600	639,500	405,000	319,700	15,100	31,700	51,500	1.3	2.6	4.7	8.6	729,000	109,400	97,200	65,100	5.23	3.96	3.49
	90	100	27	13	1,203,500	354,200	1,947,100	584,100	369,900	292,100	13,600	31,700	49,800	1.1	2.6	4.7	8.4	717,300	107,600	95,600	65,100	4.90	3.74	3.32
	80	100	24	16	931,000	354,200	1,606,500	482,000	305,200	241,000	10,400	31,700	46,400	.9	2.6	4.7	8.2	693,900	104,100	92,500	65,100	4.29	3.33	2.98
	70	100	22	18	772,100	354,200	1,707,900	422,400	267,500	211,200	8,600	31,700	44,400	.7	2.6	4.7	8.0	680,400	102,100	90,700	65,100	3.94	3.10	2.79
	100	100	30	15	1,112,700	354,200	1,833,600	550,100	348,400	275,000	12,500	31,700	48,600	1.0	2.6	6.8	10.4	871,200	130,700	116,200	88,200	5.08	3.98	3.58
	90	100	27	18	874,300	354,200	1,535,600	460,700	291,800	230,300	9,800	31,700	45,700	.8	2.6	6.8	10.2	851,400	127,700	113,500	88,200	4.54	3.62	3.29

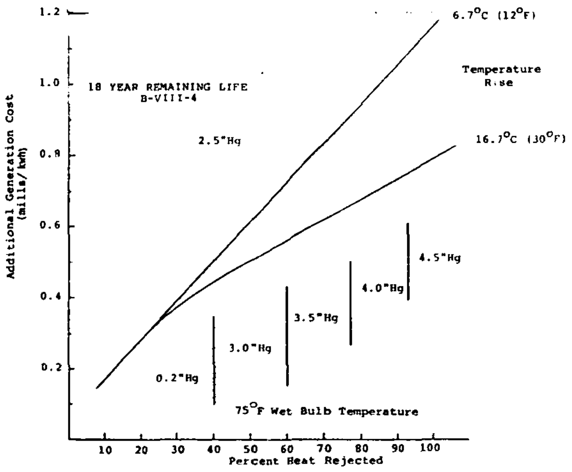


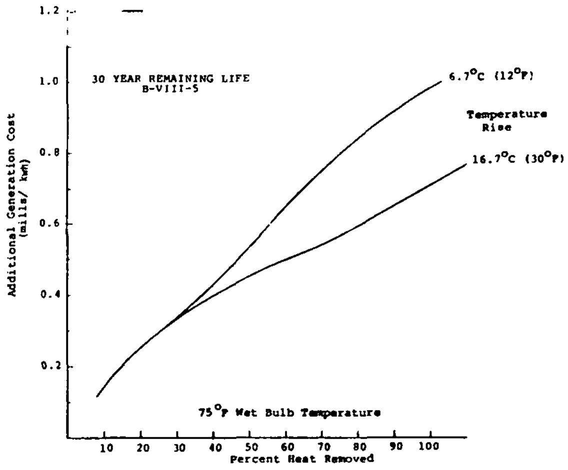




Figures B-VIII-2,3,4,5,6
ADDITIONAL GENERATING COSTS FOR
MECHANICAL DRAFT COOLING TOWERS

Base-Load Unit, 300Mw





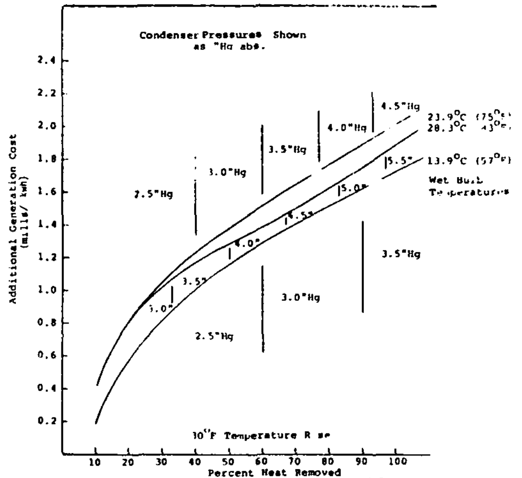
Condenser Pressures shown
as "Hg abs.

These higher costs are deceptive, because a simple change to the system can reduce the cost to approximately that at the 16.7°C (30°F) rise case. This change involves increasing the turbine exhaust pressure and then cooling only part of the circulating water to a level below that required. The required temperature is obtained when the two streams are remixed. This is possible due to the larger temperature difference between the wet bulb and cold water temperatures than in the 16.7°C (30°F) rise case. The tower cost is significantly lower due to the lower flow through it. For example, by increasing the turbine exhaust pressure to 11.8 kN/sq m (3.5 in. of Hg) and cooling 60% of the water 11.1°C (20°F), the additional generation cost is reduced from 1.0 mills/kwh to 0.7 mills/kwh. Thus the higher costs for the 6.7°C (12°F) rise case can be substantially reduced, an option not as readily available in the 16.7°C (30°F) rise case. The cost of this scheme is variable depending upon site conditions and plant layout.

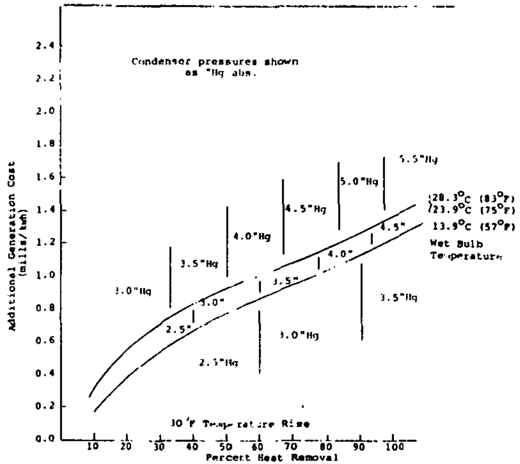
The results for the cyclic unit are shown in Figures B-VIII-7, B-VIII-8, and B-VIII-9. The curves have essentially the same shape as the base-load unit curves, however, the additional generation costs are doubled. The reason for this is that there is much less power generated in a cycling plant against which the cost of the cooling towers can be charged. With a six year remaining life, the 75°F wet bulb case results in a higher incremental cost than the 83°F wet bulb case. For the 18 and 30 year remaining lives, the costs for the 75°F and 83°F cases are the same. The capacity factor for the cycling plant is 44% versus 77% for the base-load unit. The penalties were assumed to be the same as in the base-load unit, as the cycling units would be heavily used during the summer peak load. If this were not true for specific units, the cost would be somewhat lower.

The costs for the peaking units are shown in Figures B-VIII-10, B-VIII-11, and B-VIII-12. The costs for these units are almost an order of magnitude greater than those for the base-load unit. The maximum was 11.0 mills/kwh for a unit with 6 years remaining life and the minimum was 4.5 mills/kwh for a unit with 30 years remaining life. Here again the major difference was the number of kwh's against which the cost of the cooling system could be charged. The capacity factor for peaking units used was 9% as opposed to 77% for base-load units. The change in additonal generation cost with change in capacity factor, all other factors remaining the same, can be determined from Figure B-VIII-13.

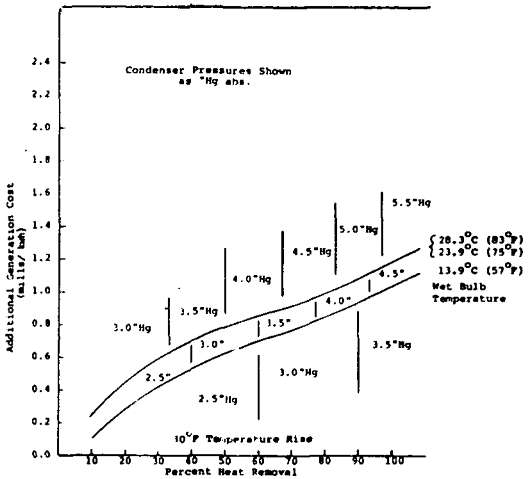
The cost of backfitting mechanical draft towers on nuclear units was also determined, using the same techniques em-



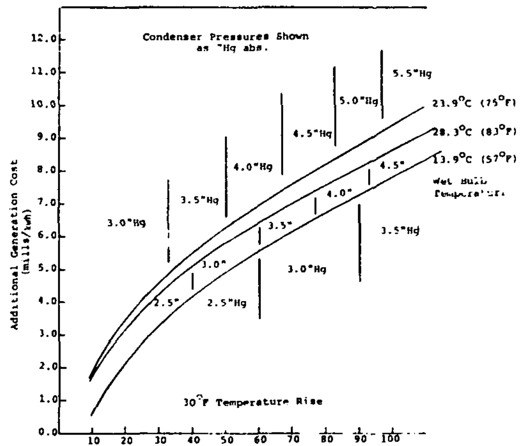
ADDITIONAL GENERATING COSTS FOR
300 Mw CYCLIC UNIT
MECHANICAL DRAFT TOWERS
6 YEAR REMAINING LIFE
Figure B-VIII-7



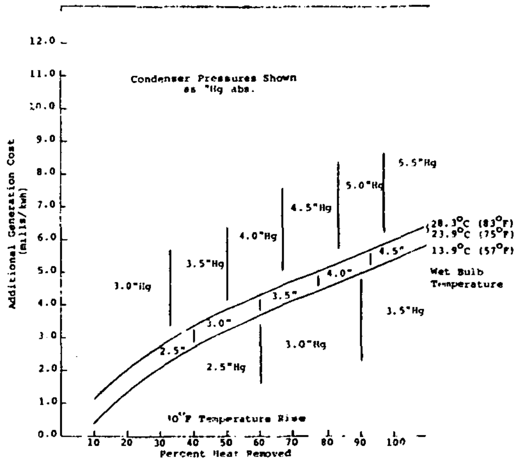
ADDITIONAL GENERATING COSTS FOR
300 Mw CYCLIC UNIT
MECHANICAL DRAFT TOWERS
18 YEAR REMAINING LIFE
Figure B-VIII- 8



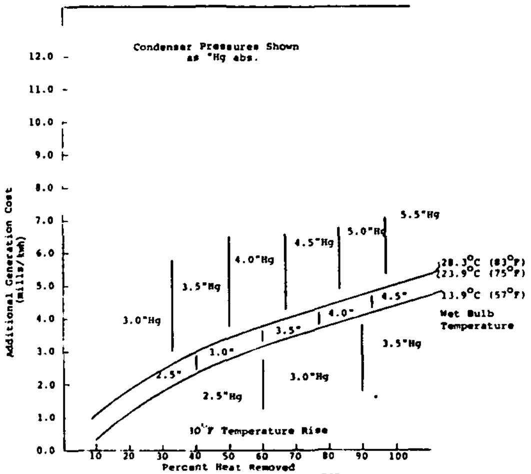
ADDITIONAL GENERATING COSTS FOR
300 Mw CYCLIC UNIT
MECHANICAL DRAFT TOWERS
30 YEAR REMAINING LIFE
Figure B-VIII- 9



ADDITIONAL GENERATING COSTS FOR
300 Mw PEAKING UNIT
MECHANICAL DRAFT TOWERS
6 YEAR REMAINING LIFE
Figure B-VIII-10



ADDITIONAL GENERATING COSTS FOR
300 Mw PEAKING UNIT
MECHANICAL DRAFT TOWERS
18 YEAR REMAINING LIFE
Figure B-VIII-11



ADDITIONAL GENERATING COSTS FOR
300 Mw PEAKING UNIT
MECHANICAL DRAFT TOWERS
30 YEAR REMAINING LIFE
Figure B-VIII-12

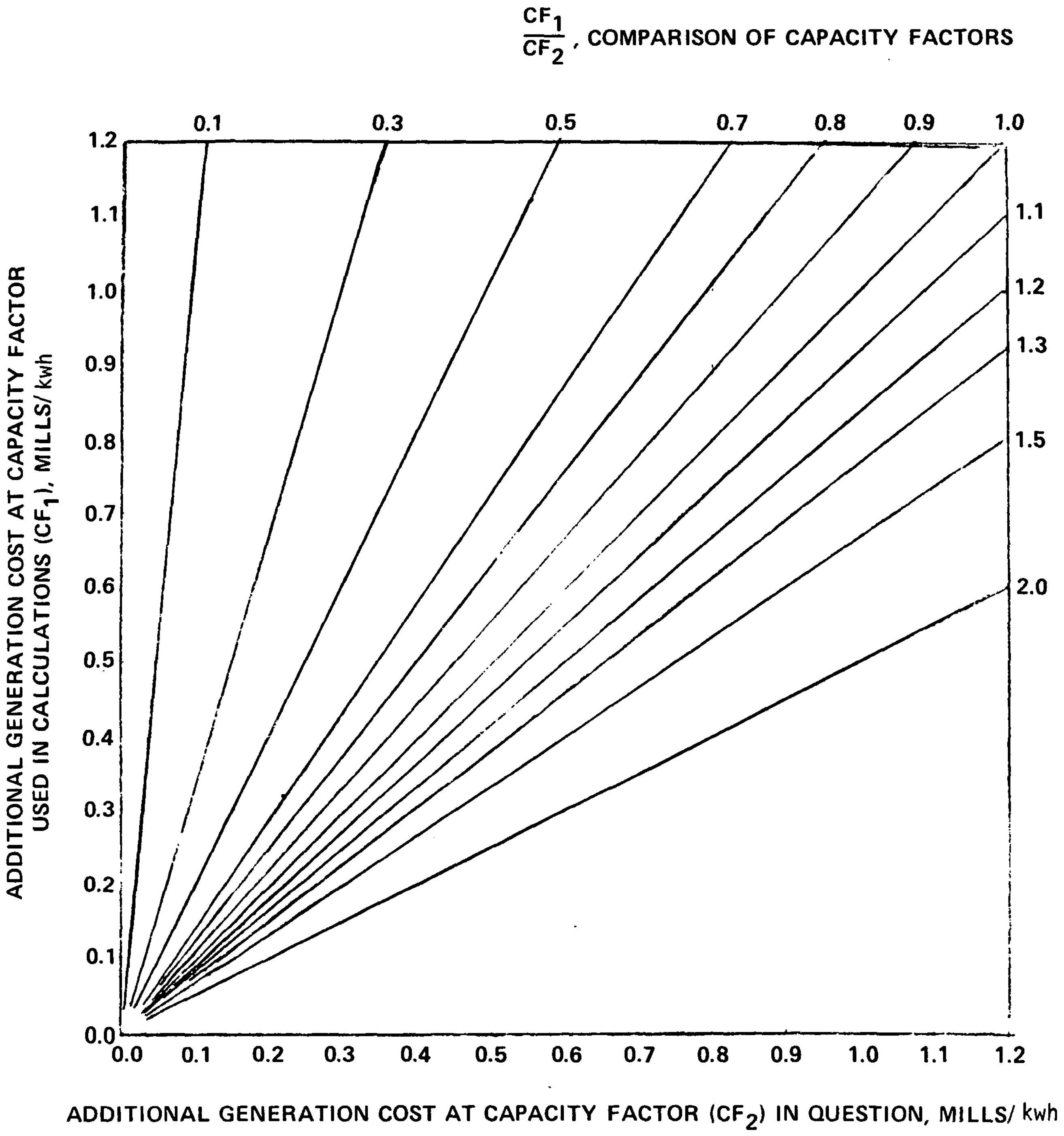
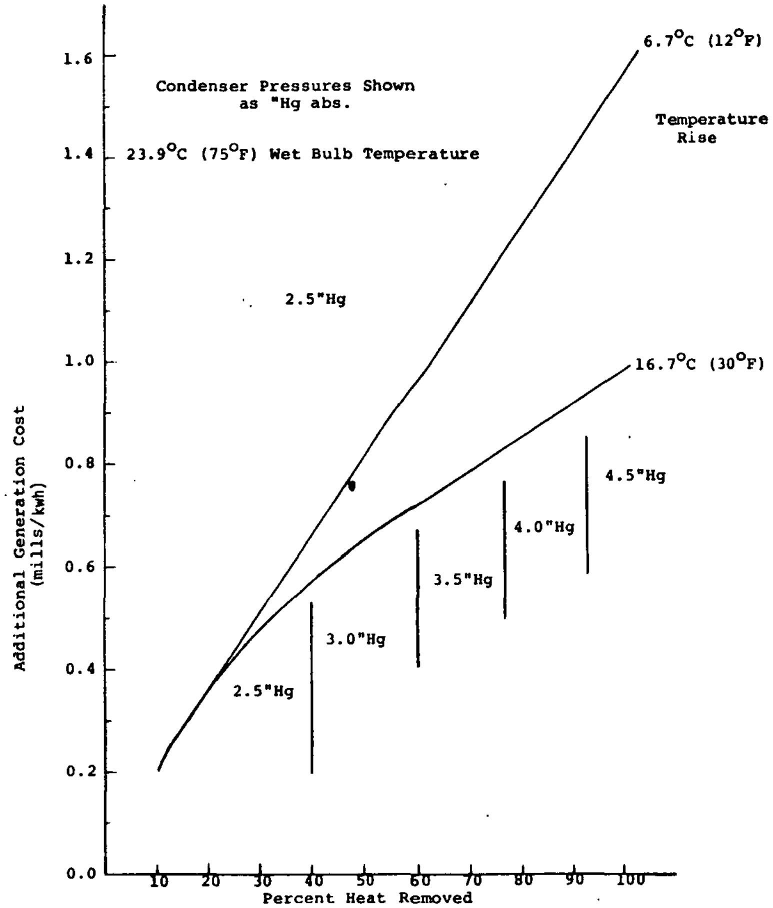


FIGURE B-VIII-13 VARIATION OF ADDITIONAL GENERATING COST WITH CAPACITY FACTOR ployed for the 300 Mw fossil-fueled plant. Except for a few small experimental units, most nuclear facilities fall in the 500 to 1000 Mw size range. An 800 Mw nuclear unit was assumed for the economic analysis. The heat rate assumed was 11,088 kJ/kwh (10,500 Btu/kwh), with 6,864 kJ/kwh (6,500 Btu/kwh) being rejected through the condenser. Two circulating water temperature rises were used, 16.7°C and 6.7°C (30°F and 12°F). The remaining assumptions were essentially the same as for the 300 Mw fossil-fueled unit. Since there are no large nuclear units over ten years old, only 18 and 30 years remaining lives were considered. All nuclear units presently are intended for base-load service, so only the base-load case was considered. Wet bulb temperature used for tower design was 23.9°C (75°F). Capacity factor used was 70%.

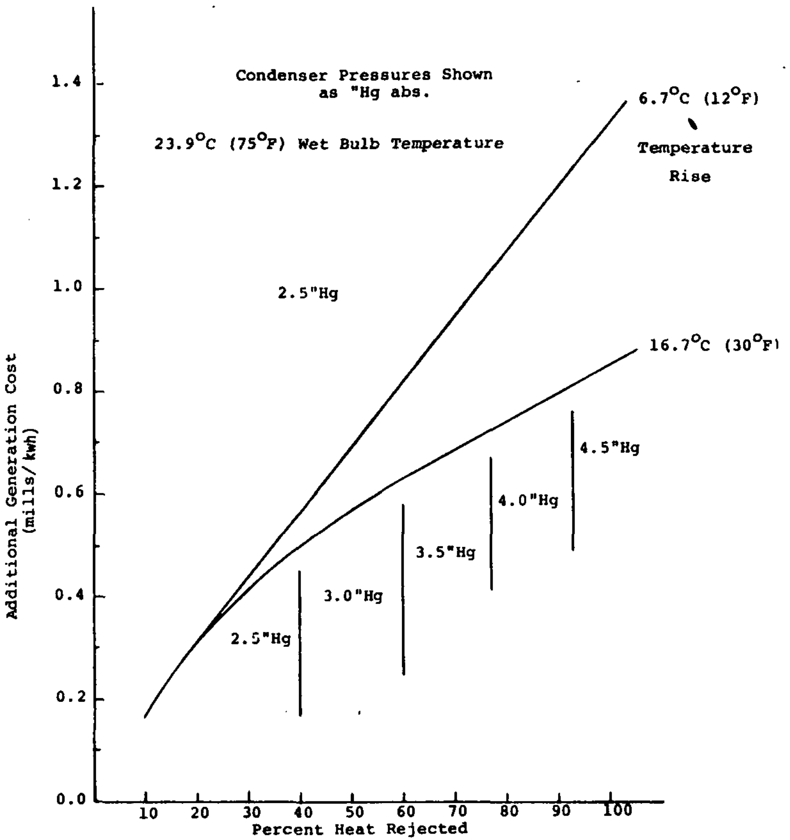
The costs resulting from this analysis are shown in Figures B-VIII-14 and B-VIII-15. For the 16.7°C (30°F) rise, the additional generation cost was higher than for the fossil-fueled unit due to the increased heat rejection to the water as expected. Here again the case where the circulating water rise was 6.7°C (12°F) was the most expensive. However, the comments concerning this in the fossil-fueled analysis are equally applicable to this case.

Two sets of estimated cost for retrofitting existing powerplants were submitted as comments by the Utility Water Act Group (UWAG).[388] The first of these analyses, prepared by Sargent and Lundy Engineers[447], addressed the retrofit of a hypothetical matrix of plants which was selected to represent variations in the basic design parameters that affect the cost of installing closed cooling systems at existing plants. The Sargent and Lundy analysis is similar to the cost analysis presented above and performed by Burns and Roe in its draft development document. The results of these two analyses are compared in Table B-VIII-16.

The second set of estimated costs submitted by UWAG is a tabulation of a survey of utilities, each of which estimated the cost of retrofitting plants in its system. This survey is contained in Volume I of the UWAG comments. These estimates are generally higher than those from the Sargent and Lundy analysis, since they include site related costs not fully accounted for in the hypothetical analysis. The results of the utility survey can be compared with the cost curves shown in this document. These cost curves, prepared by EPA, also reflect higher allowances for site related conditions. The utility estimates and those of EPA are compared in Table B-VIII-17.



ADDITIONAL GENERATING COSTS FOR
800 Mw NUCLEAR UNIT
MECHANICAL DRAFT TOWERS
18 YEAR REMAINING LIFE
Figure B-VIII-14



ADDITIONAL GENERATING COSTS FOR
800 Mw NUCLEAR UNIT
MECHANICAL DRAFT TOWERS
30 YEAR REMAINING LIFE
Figure B-VIII-15

Table B-VIII-16

COMPARISON OF B&R ECONOMIC ANALYSIS OF RETROFITTING COOLING TOWERS WITH SARGENT & LUNDY ANALYSIS

No. of Plants in Analysis	Burns and Roe Analysis[1]				Sargent and Lundy Analysis[2]			
	27				92			
		Increased Generating Cost (Mills/kwh)				Increased Generating Cost (Mills/kwh)		
Category	No.	Max.	Min.	Avg.	No.	Max.	Min.	Avg.
Peaking Units	9	5.70	2.90	4.30	3	5.71	2.60	3.90
Cycling Units	9	1.31	0.64	0.98	32	1.74	0.28	0.93
Base Loaded Units	9	0.62	0.31	0.46	54*	1.28	0.25	0.44
	27				89			

* Note that the S&L Analysis deletes 3 base loaded plants as "infeasible".

[1] From Development Document for Effluent Limitation Guidelines and Standards of Performance for Steam Electric Power Plants, Burns & Roe, Inc., June 1973, Figures B-VIII-1-3, B-VIII-9-14.

[2] UWAG comments on EPA proposed guidelines, Vol. 1, Attachment III - Appendix A, June 1974.

Table B-VIII-17

COMPARISON OF UTILITY SURVEY OF RETROFITTING COSTS WITH EPA COST CURVES

No. of Plants in Analysis	EPA Cost Curves 27				Utility Survey[1] 92			
		Increased Generating Cost (Mills/kwh)				Increased Generating Cost (Mills/kwh)		
Category	No.	Max.	Min.	Avg.	No.	Max.	Min.	Avg.
Peaking Units	9	9.30	4.30	6.22	2	2.26	2.26	2.26
Cycling Units	9	2.00	1.02	1.44	97 (94)	5.81 (3.40)	0.72 (0.72)	1.70 (1.58)
Base Loaded Units	9	1.12	0.60	0.84	25 (23)	2.08 (1.89)	0.46 (0.46)	0.94 (0.84)
	27				124*			

* Note: In addition to the 124 units reported here the utility survey included 13 units for which the costs could not be broken out and 2 units scheduled for retirement.

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[1] UWAG comments on EPA proposed guidelines, Vol. 1, Attachment III, Appendix D, June 1974.

The variables considered in the Sargent and Lundy (S&L) matrix included weather conditions, stream temperatures, capacity factor, unit age, extent of turbine back-end loading, type of cooling and circulating water flow rate. The Burns and Roe (B&R) analysis also used these same variables, except for cooling type back-end loading, and stream temperatures. The inclusion of these two additional variables in the S&L analysis required a larger matrix (92 units) than used in the B&R analysis (27 units). Estimated capital costs in the two analysis were approximately the same. For instance, the average construction cost for the 6 schemes for S&L's 411 Mw fossil plant ($7.97/kw) compares to the average construction cost of B&R's schemes for it's 300 Mw fossil plant ($7.30/kw). Both analyses allowed for both capacity losses and energy losses as supplied by combustion turbines. S&L allowed $106/kw for replacement capacity and B&R used $90/kw. S&L estimated the cost of make-up energy to be $.98/10^6 Btu which is equivalent to the B&R estimate of 10 mills/Kwh for new gas turbines with heat rates of 10,000 Btu/Kwh. The major difference between the two analysis was that the S&L analysis optimized the tower design with respect to the individual condenser-turbine sets whereas the B&R analysis did not. One would expect the increased generating costs estimated by the S&L analysis to be slightly lower than those estimated by the B&R analysis.

The comparison of the results of the two analyses is shown in Table B-VIII-16. As can be seen from the table, the average increase in generating cost resulting from the S&L analysis is close to that estimated in the B&R analysis in all three categories. For instance, the S&L analysis shows an average increase of 0.44 mills/Kwh for 54 base loaded units. The comparible number from the B&R analysis is 0.46 mills/Kwh. The comparisons for the other two categories are also close. In all three cases the S&L estimate is slightly lower, which reflects their tower optimization process.

Based on this comparison, it is concluded that the two independent analysis are complementary and that the costs for retrofitting power plants, exclusive of site related factors, are satisfactorily established. The EPA cost curves are shown in this document. The curves are based on the original B&R analysis but contain a substantial allowance (300% of tower base cost) for site related factors which can increase the fixed cost of cooling tower installations at some locations.

The utility survey represents the separate estimates of eight utilities of the costs of retrofitting the units in their individual systems. The factors considered and the format used for reporting the results is identical to that used in the S&L analysis. However, these estimates do include the costs associated with the various site related factors that would be experienced at the separate plant locations. The total number of units in the utility survey was 139. Of these, 124 are included in the comparisons. Thirteen additional units were not included since the costs were reported on combinations of units which did not permit breaking out of costs for peaking, cycling and base load units. Two additional units in the utility survey were scheduled for retirement and no costs were provided.

The comparison of the results of the EPA estimates and that of the utility survey is shown on Table B-VIII-17. The cost for retrofitting peaking units cannot be estimated from the utility survey data since only 2 units were separately estimated. Six other peaking units were reported, however, the costs of retrofitting for these units were combined with cycling and base loaded units. While there is some difference between the maximum and minimum costs for individual units, the average costs of retrofitting are fairly close for both base-loaded and cycling categories. For instance, the average cost for retrofitting 25 base loaded units, as estimated in the utility survey is 0.94 mills/Kwh. This compares to an average cost for retrofitting the 9 base loaded units in the EPA analysis of 0.84 mill/Kwh. Similarly, the estimated cost for the cycling category is 1.70 mills/Kwh from the utility survey and 1.44 mills/Kwh from the EPA curves. In addition, the utility survey is strongly influenced by extremely high costs for relatively few units. For instance, if the two most costly units were removed from the utility analysis, the remaining 23 units could be retrofitted at an average cost of 0.84 mills/Kwh, which is identical to the EPA estimate. If the three most costly cycling units were removed from the utility analysis the remaining 94 units could be retrofitted at an average cost of 1.58 mill/Kwh a figure which is roughly 10% higher than the EPA estimate.

In summary, it appears that there is reasonable agreement between EPA and the industry on the cost estimates upon which the thermal effluent guidelines are based. First, the theoretical basis used by B&R for establishing retrofitting costs, exclusive of site related factors, is in close agreement withe the results of the Sargent and Lundy analysis. Moreover, the results of the EPA cost analysis, which includes a large allowance for site related costs, are also in close agreement with the results of the utility survey at least for the cycling and base loaded categories.

Energy (Fuel) Requirements

Energy significantly in excess of that normally required by the circulating water system is required to operate all cooling systems except the cooling pond. With spray canals, the water is pumped into the spray nozzle. The natural draft tower requires the water to be pumped to the top of the packing. In the mechanical draft tower, in addition to pumping the water to packing, power is required to run the fans which move the air through the tower. The amount of energy required varies by a factor of three for mechanical draft towers due to its dependency on condenser design and climatic conditions. A condenser with a high flow rate and low temperature rise requires more pumping energy than a condenser with a lower flow rate and higher rise, for the same size plant. With adverse climatic conditions, more air is required, resulting in bigger fans requiring more energy.

Fan motors for mechanical draft cooling towers are about 0.2 percent of the unit generating capacity; pump motors are about 0.5 percent. However, fans and pumps need not be operated continuously year round. Both fan power and pump power can be reduced along with the generating demand. Furthermore, fan power can be reduced when climatic conditions permit to optimize the net unit power output. Only incremental pumping power should be considered as chargeable to closed cooling systems. Incremental energy (fuel) consumption due to fans and pumps with mechanical draft cooling towers is estimated to be approximately 0.7 percent of base energy (fuel) consumption. With natural draft towers and spray systems there is no fan power but incremental pumping power is estimated to be approximately 0.7 percent or less of base fuel consumption. With cooling ponds there is no fan power and pumping power would be approximately the same as with once-through systems.

A further source of incremental energy (fuel) consumption due to closed-cycle cooling systems is the incremental steam cycle inefficiency due to changes in the turbine backpressure. In many cases higher turbine backpressures will result after backfitting closed-cycle cooling systems. In these cases the higher backpressures will result in incremental steam cycle inefficiencies during part of the year. The incremental fuel consumption over any span of time due to this factor is a product of the average incremental inefficiency over that span and the power generated over the span. For example, the fuel consumption penalties due to increased turbine backpressure from a closed-cycle cooling system (See Figure B-VIII-16) is shown in Table B-VIII-18. The maximum penalty during any month is

Figure B-VIII-16

TURBINE EXHAUST PRESSURE CORRECTION FACTORS (EXAMPLE, PLANT NO. 3713)

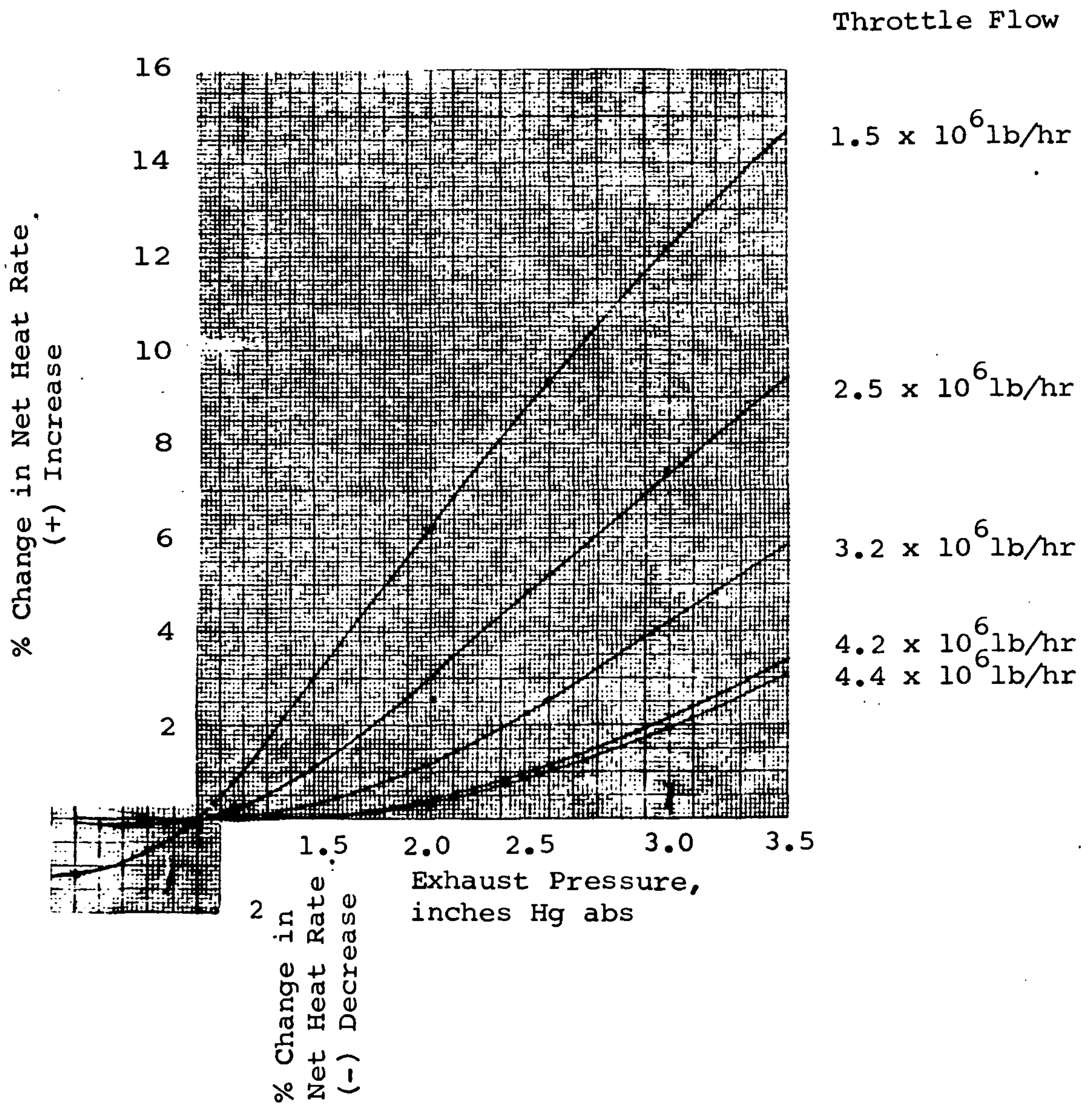


Table B-VIII-18

ENERGY (FUEL) CONSUMPTION PENALTY DUE TO INCREASED TURBINE BACKPRESSURE
FROM CLOSED-CYCLE COOLING SYSTEM ***
Example calculated for plant no. 3713

Month	Dew Point Temp., °F	Air Temp., °F	Wet Bulb Temp., °F	Condenser Outlet Temp., °F	Condensing Temp., °F	Backpressure, in. of Hg	Fuel Penalty*, % of base
J	32	42	38	68	73	0.82	0.1**
F	32	43	39	69	74	0.85	0.1**
M	36	50	43	73	78	0.97	0.0
A	46	59	52	82	87	1.29	0.0
M	56	68	60	90	95	1.66	0.1
J	64	75	68	98	103	2.11	0.5
J	67	78	70	100	105	2.24	0.7
A	67	77	70	100	105	2.24	0.7
S	61	71	64	94	99	1.88	0.3
O	50	61	55	85	90	1.42	0.2
N	39	50	45	75	80	1.03	0.0
D	32	42	38	68	73	0.82	0.1**
						Annual Average	0.2

** Note: This plant normally reduces the flowrate of cooling water in the winter to minimize this type of penalty, therefore flowrate reduction with the closed-cooling system is also assumed to eliminate the penalty during the winter months.

* Note: Assumes no penalty for once-through system, which is probably the case for plant no. 3713. Some penalty for once-through systems could occur for other plants during the summer months.

*** Note: The values given in the table are computed from mean values for each month. The maximum backpressure penalty for which the cooling ststem would be designed to operate would be base on the wet bulb temperature which would be exceeded no more than 5% of the time during the three months of summer. For plant no. 3713, this wet bulb temperature is 80°F and the maximum backpressure penalty is 2.1%.

0.7 percent of base fuel consumption during that month. Assuming uniform power generating from month to month, the annual penalty is 0.2 percent of base fuel consumption. The greatest fuel penalty expected would occur when the wet bulb temperature reaches the maximum level for which the evaporative cooling system is designed, i.e. the wet bulb temperature which is exceeded no more than 5% of the time during June, July, August and September. For the plant shown the maximum penalty is 2.1%. In the case of a new source the penalties would not be as great due to the opportunities to optimize the design of both the steam system (turbine, etc.) and the cooling system.

The total annual fuel penalty for the example above is 0.9 percent of base fuel consumption, assuming that the power generated from month to month is about the same. If the plant shown generates twice as much power during the months of June through September compared to other months, the annual backpressure penalty would approximately double to 0.4 percent, increasing the overall annual penalty to 1.1 percent of base fuel consumption. Based on the analysis above, an annual fuel penalty of 2 percent of base fuel consumption would be conservative.

Loss of Generating Capacity

In the case of Plant no. 3713 described in the above discussion of fuel requirements, the loss of generating capacity imposed by a closed-cycle cooling system would be the sum of the fan power and pump power requirements (0.7%) and the maximum backpressure penalty (2.1%), or a total of 2.8% of nameplate generating capacity. While the direct effects of these penalties would be felt as lost generating capacity only when the demand for generation and climatic conditions coincide to actually limit generation to below nameplate capacity, the probability of such an occurrence must be considered in system planning leading to the construction of replacement generating capacity.

Site-Dependent Factors

The analysis of the cost involved in installing cooling devices on the circulating water systems assumed average site conditions. At any particular station, costs will be affected by specific conditions existing at the site. Some of the more important factors are addressed in detail below.

Reference 447 examined, by computer simulation, the effects of wet-bulb temperature, circulating water flowrate, stream temperature, extent of turbine back-end loading, dry bulb temperature, and other factors on equipment costs, capability losses, energy losses, and generating costs. The results are summarized in Tables B-VIII-19 through B-VIII-22.

Age

The cost, expressed in relation to power generated, is inversely related to the number of years of service life remaining for a particular generating unit. That is, the shorter the remaining useful life over which the cost of the cooling system may be amortized, the greater will be the percentage of the capital cost charged against each unit of power generated. Moreover, the shorter the remaining useful life, the less heat will be rejected to the environment particularly since many older units traditionally operate only during periods of higher demand. Accordingly, the capital cost expressed as a function of units of heat removed will be greater for older plants. In addition the absolute cost of retrofitting existing once-through units with closed-cycle cooling is substantially greater than is the cost of installing cooling equipment at new units.

Assuming the capital cost of retrofitting closed-cycle cooling systems to steam-electric generating units to be a function of generating capacity only, the costs versus effluent reduction benefits function for units of a given capacity would be determined by the remaining life of the units and the capacity factor for the unit over its remaining life. If it is assumed that the useful life of all generating units is 35 years (with the following capacity factors: year 1 through 20, 0.7 capacity factor; year 21 through 30, 0.4 capacity factor; year 31 through 35, 0.1 capacity factor) then a cost versus effluent reduction benefit function can be established for thermal controls, as a function of the age of the unit when controls are implemented, as shown in Figure B-VIII-17. As can be seen from the figure, the costs/effluent reduction benefits increases gradually as the age of the unit increases with the costs/benefits of a unit 5 years old being about 20% greater than for retrofitting a unit of zero age, and about 60% greater for a unit 10 years old, which is half-way through its assumed base-load service life. After this age, the costs/benefits increases rapidly to about 120% greater than the zero age unit at age 15 and 300% greater at age 20 which is the end of its assumed base-load service life. During cyclic service, at age 25, the costs/benefits are over 800% greater than for the zero age unit.

Table B-VIII-19

Computer Simulation of Costs[447] of Retrofitting Cooling Towers

MECHANICAL DRAFT – 411 MW UNITS*
72% CAPACITY FACTOR

Equipment Cost ($/KW)

1% Wet Bulb	(°F)	65			78			82
gpm/MW		300	600	1100	300	600	1100	600
		7.97	9.10	9.80	8.57	9.71	10.41	11.37

Capability Losses (%)

1% Wet Bulb	(°F)	65			78			82
gpm/MW		300	600	1100	300	600	1100	600
1% Stream Temp.	(°F)							
	58	1.7	1.4	1.8	2.4	2.4	2.7	--
	78	1.4	1.5	1.8	2.1	2.5	2.7	1.43
	93	−0.4	1.1	1.8	0.3	2.1	2.7	--

Energy Losses (%)

1% Wet Bulb	(°F)	65			78			82
gpm/MW		300	600	1100	300	600	1100	600
1% Stream Temp.	(°F)							
	58	0.7	0.8	0.7	0.7	0.7	0.7	--
	78	0.7	0.8	0.7	0.7	0.7	0.7	1.16
	93	0.6	0.7	0.8	0.7	0.7	0.7	--

Total Cost (mills/KWH)

1% Wet Bulb	(°F)	65			78			82
gpm/MW		300	600	1100	300	600	1100	600
1% Stream Temp.	(°F)							
	58	0.32	0.34	0.35	0.35	0.36	0.40	--
	78	0.31	0.34	0.35	0.34	0.36	0.40	.45
	93	0.25	0.33	0.37	0.29	0.37	0.40	--

* Note: High back-end loaded

Table B-VIII-20

Computer Simulation of Costs[447] of Retrofitting Cooling Towers

MECHANICAL DRAFT – 535 MW UNITS *
44% CAPACITY FACTOR

Equipment Cost($/MW)

1% Wet Bulb	(°F)	65			78			82		
gpm/MW		300	600	1100	300	600	1100	300	600	1100
		11.40	12.23	11.93	11.40	12.23	13.42	11.86	13.70	13.42

Capability Losses ($)

1% Wet Bulb	(°F)	65			78			82		
gpm/MW		300	600	1100	300	600	1100	300	600	1100
1% Stream Temp.	(°F)									
	58	3.63	2.86	2.80	5.75	4.32	3.88	6.48	4.47	4.43
	78	.31	1.44	2.11	2.49	2.90	3.18	3.15	3.06	3.74
	93	-3.74	-1.20	.23	-1.62	.25	1.30	-.90	.40	1.85

Energy Losses ($)

1% Wet Bulb	(°F)	65			78			82		
gpm/MW		300	600	1100	300	600	1100	300	600	1100
1% Stream Temp.	(°F)									
	58	2.38	2.33	2.53	2.77	2.56	2.52	4.78	3.79	4.32
	78	1.26	1.84	2.23	1.65	2.07	2.28	3.67	3.29	4.00
	93	-.06	1.08	1.66	.33	1.18	1.71	2.35	2.54	3.43

Total Cost (Mills/KWH)

1% Wet Bulb	(°F)	65			78			82		
gpm/MW		300	600	1100	300	600	1100	300	600	1100
1% Stream Temp.	(°F)									
	58	.88	.88	.88	1.02	.96	.99	1.31	1.18	1.23
	78	.61	.76	.82	.74	.85	.93	1.04	1.06	1.16
	93	.28	.55	.67	.41	.63	.78	.78	.85	1.02

* Note: Medium back-end loaded

Table B-VIII-21

Computer Simulation of Costs of Retrofitting Cooling Towers

NATURAL DRAFT – 411 MW UNITS *
72% CAPACITY FACTOR

Equipment Cost($/MW)

1% Wet Bulb	(°F)	65						78					
1% Dry Bulb	(°F)	82			96			92			111		
gpm/MW		300	600	1100	300	600	1100	300	600	1100	300	600	1100
		12.47	12.91	13.30	13.29	13.72	13.91	13.74	14.18	15.11		14.18	15.18

Capability Losses (%)

1% Wet Bulb	(°F)	65						78					
1% Dry Bulb	(°F)	82			96			92			111		
gpm/MW		300	600	1100	300	600	1100	300	600	1100	300	600	1100
1% Stream Temperature	58	2.00	1.95	2.34	2.15	2.12	2.55	2.52	2.85	3.51		2.95	3.41
	78	1.67	2.00	2.40	1.81	2.17	2.61	2.18	2.91	3.57		3.01	3.46
	93	-.123	1.66	2.33	.037	1.84	2.54	.393	2.55	3.52		2.65	3.4

Energy Losses (%)

1% Wet Bulb	(°F)	65						78					
1% Dry Bulb	(°F)	82			96			92			111		
gpm/MW		300	600	1100	300	600	1100	300	600	1100	300	600	1100
1% Stream Temperature	58	0.43	0.44	0.45	0.55	0.54	0.63	0.52	0.51	0.51		0.72	0.82
	78	0.43	0.44	0.45	0.55	0.55	0.63	0.52	0.52	0.51		0.73	0.81
	93	0.36	0.45	0.45	0.47	0.55	0.64	0.44	0.53	0.52		0.73	0.82

Total Cost (mills/KWH)

1% Wet Bulb	(°F)	65						78					
1% Dry Bulb	(°F)	82			96			92			111		
gpm/MW		300	600	1100	300	600	1100	300	600	1100	300	600	1100
1% Stream Temperature	58	.4	.41	.43	.44	.45	.47	.45	.47	.51		.50	.54
	78	.39	.41	.43	.43	.45	.47	.44	.47	.51		.50	.55
	93	.34	.41	.43	.37	.45	.47	.39	.47	.51		.49	.55

* Note: High back-end loaded

Table B-VIII-22

Computer Simulation of Costs[447] of Retrofitting Cooling Towers

MECHANICAL DRAFT - 82°F WET BULB
78° F STREAM TEMPERATURE
600 GPM/MW

Equipment Cost ($/Kw)

MWe	411 *	275 **	535 ***
Capacity Factor			
72	11.37	17.785	13.695
44	11.37	17.785	13.695
9	11.37	17.785	11.258

Capability Losses (%)

MWe	411	275	535
Capacity Factor			
72	1.43	6.23	3.067
44	1.43	6.23	3.067
9	1.43	6.23	3.875

Energy Losses (%)

MWe	411	275	535
Capacity Factor			
72	1.157	5.740	2.672
44	1.727	6.669	3.298
9	1.156	8.760	3.700

Total Cost (Mills/KWH)

MWe	411	275	535
Capacity Factor			
72	.448	1.284	.986
44	.713	1.764	1.063
9	2.597	5.715	3.391

* Note: High back-end loaded
** Note: Low back-end loaded
*** Note: Medium back-end loaded

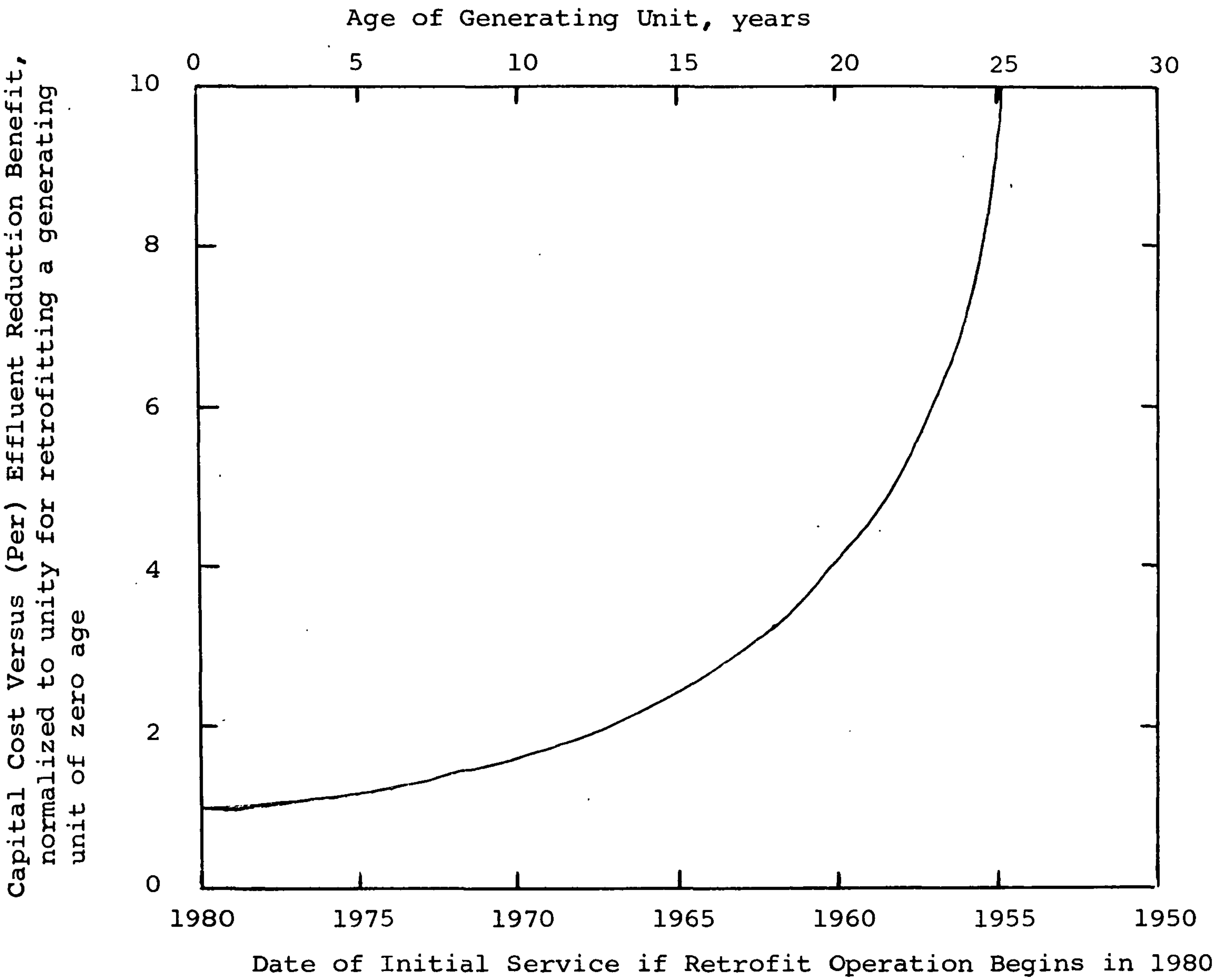


Figure B-VIII-17 Costs/Benefits of Retrofitting Versus Age of Unit

National Economic Research Associates (NERA) projected[383] the percentage distribution of the 1983 U.S. generation by the cost of closed-cycle cooling in mills/Kwh (See Figure B-VIII-18), which includes the effect of the age of units.

Size

Assuming that, based on costs versus effluent reduction benefits, retrofitting of thermal controls would affect only those units placed into service in 1970 and thereafter, an analysis was performed to ascertain the relation of the capital cost of retrofitting mechanical draft cooling towers to the generating capacity of the unit in question. As a basis for the costs, the data submitted to EPA by the Utility Water Act Group were used, which resulted from a survey of utilities and which include the effects of site-dependent factors. The data used are displayed in graphical form on Figure B-VIII-19. In all, data representing 44 generating units were used, ranging in size from 70 megawatts to 1300 megawatts generating capacity. Capital costs ranged from $13.98/kw to $33.08/kw of generating capacity. A statistical representation of the data using the method of least squares indicates that, in general, the capital cost of retrofitting ($/kw) decreases with increasing unit size (generating capacity). The average capital cost of the sample was $25.63/kw, and the statistical representation of the data indicates that this is the most likely cost for a unit with a capacity of about 500 megawatts. Based on the statistical representation, the capital costs for retrofitting a 100 Mw unit could most likely be about $30/kw, and for a 1000 Mw unit the most likely cost could be about $21/kw.

There are a very large number of small units (defined by the Federal Power Commission as units in plants of 25 megawatts or less and in systems of 150 megawatts total capacity or less). Yet these systems and units represent only a very small percentage of the total installed generating capacity in the United States. Moreover, the potential for higher costs due to site specific pecularities at any given unit could be expected to be balanced by more favorably located units in a larger utility system. In very small systems, this expectation of counterbalancing unit costs is less justifiable and the costs of meeting the thermal limits may not be economically achievable.

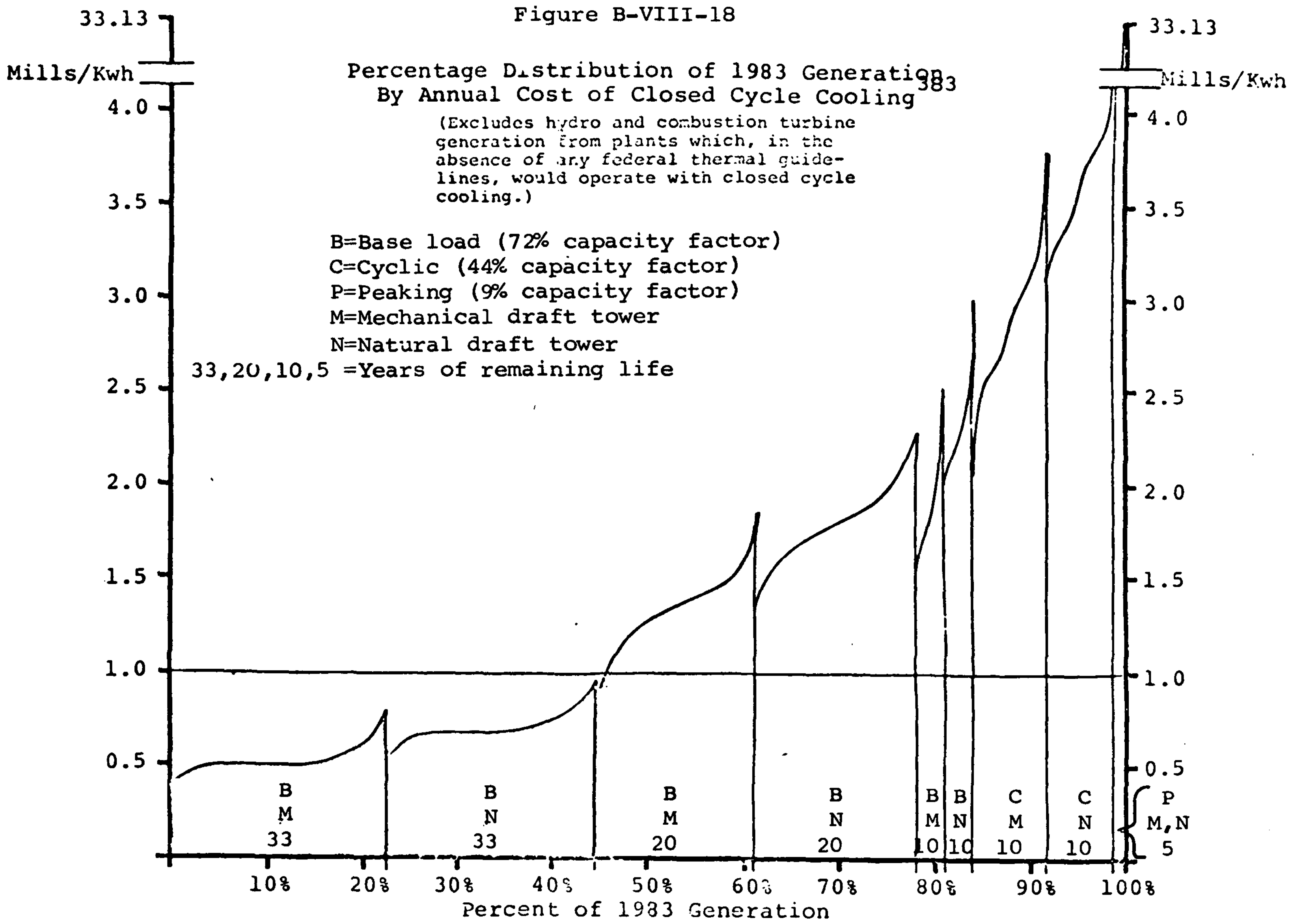
Site-Dependent Factors in General

During the comment period, industry representatives supplied two sets of data on the cost of installation of mechanical

Figure B-VIII-18

Percentage Distribution of 1983 Generation
By Annual Cost of Closed Cycle Cooling

(Excludes hydro and combustion turbine generation from plants which, in the absence of any federal thermal guidelines, would operate with closed cycle cooling.)



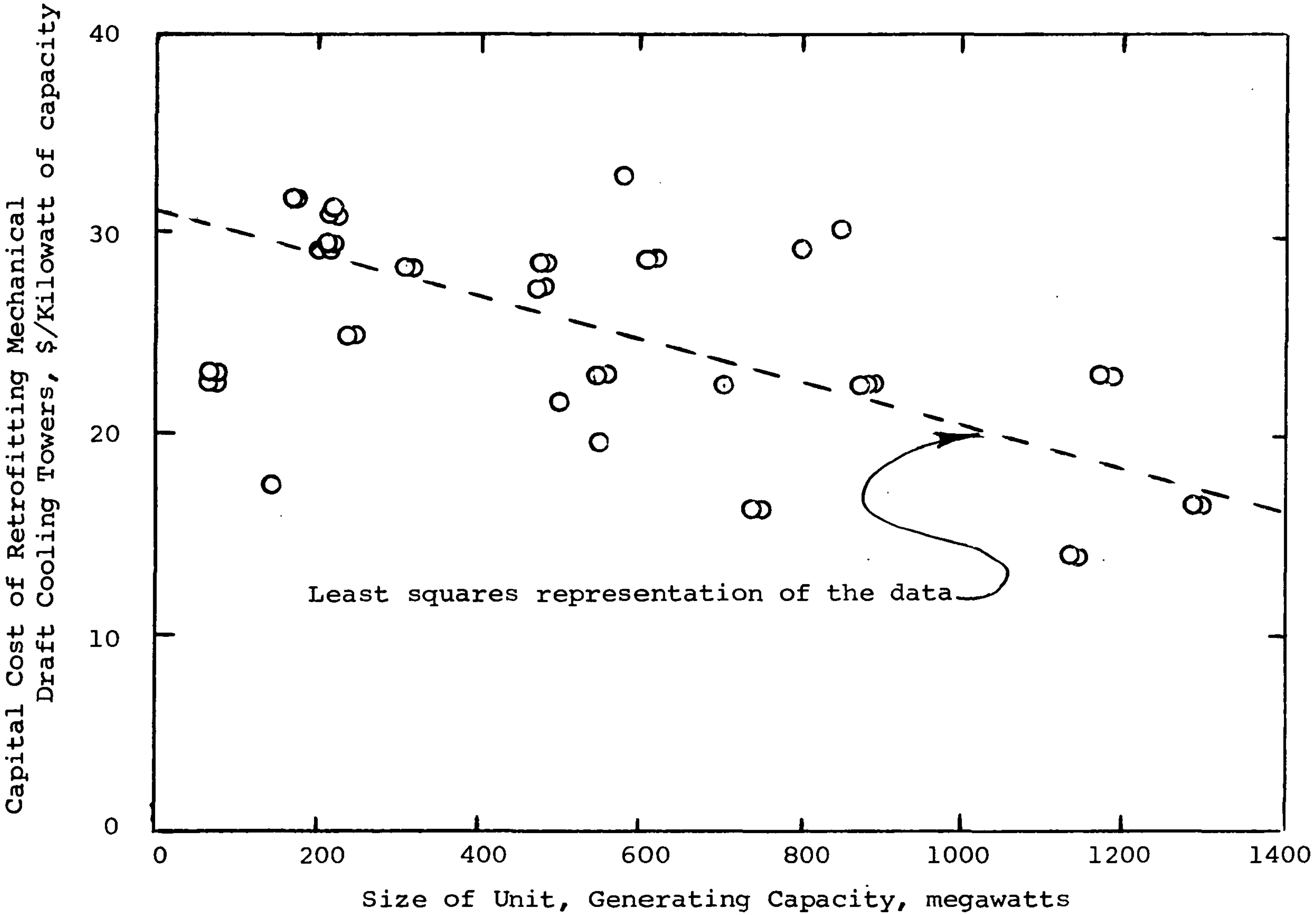


Figure B-VIII-19 Capital Cost of Retrofitting Mechanical Draft Cooling Towers to Units Placed into Service after 1970 Versus Size of Unit draft cooling towers.[383] The first was a report of an engineering firm experienced with the construction of cooling towers. Its estimate of the capital cost of retrofitting, on a per kilowatt basis, was only slightly higher than that used in the Agency's original cost estimates of the proposed regulation.

The second was based on a survey of 60 plants, in several utility systems, which represent approximately 12 percent of the total steam electric generating capacity in the United States. The results of the survey are summarized in Table B-VIII-23 The average capital cost of this survey was significantly higher than the previous industry estimate; the disparity being accounted for by the commenter on the ground that the higher estimates reflected additional costs attributable to site-specific factors. The variability of the plant by plant costs reported in the latter survey approximates a normal distribution and ranges from about $9 per kilowatt to about $81 per kilowatt. The median of the sample and the capacity weighted average cost is $21.9 per kilowatt. Only three (5%) of the plants reported per kilowatt costs significantly above the average value (in excess by 100 percent or more.) The few exceptions with extraordinarily high cost per kilowatt represent about 3 percent of the generating capacity covered by the sample. Since the extensive sample of cost estimates from individual plants addresses all site dependent factors in most instances, and includes to some extent costs corresponding to the factors addressed specifically below, EPA has determined that the sample adequately depicts the effects of the total of the site dependent factors that materially influence the costs of achieving the effluent limitations on heat. While the estimated costs of implementing thermal controls at three of the plants were reported to reflect costs in excess of twice the median cost, these incremental cost factors would not significantly affect the economic achievability of the effluent limitations. Favorable and unfavorable site-dependent factors may be ,expected to counterbalance one another, when applied across the several units at individual plants and the numerous plants in an electrical generating system. Hence, the average of the cost estimates reported in the 60 plant sample represents a realistic estimate of the retrofitting costs likely to be encountered by any utility system except the very smallest. Even in the extraordinary case of the one plant in the 60 plant sample reporting a cost estimate of $81 per kilowatt, the incremental cost (above that within which 95 percent of plants estimated costs reflecting site specific factors) would not affect the economic achievability of the thermal limitations. For example, the abnormal incremental costs at

Table B-VIII-23

SUMMARY OF SELECTED UTILITIES CAPITAL COSTS, CAPABILITY LOSSES AND ENERGY LOSSES FOR MECHANICAL DRAFT AND NATURAL DRAFT COOLING TOWERS 383
(1973 Dollars)

Site Capacity (Mw) (1)	Tower, Pump, Other Equipment Costs and Site Preparation Costs ($/Kw) (2)	Capability Losses[1] (Percent) (3)	Energy Losses[1] (Percent) (4)
	Mechanical Draft Cooling Towers		
2,600	$14.83	1.42%	1.26%
1,100	21.57	1.30	1.43
1,575	19.75	1.98	2.55
175	19.75	1.90	2.17
1,312	19.09	1.67	2.32
892	21.21	1.05	1.53
550	18.26	1.21	1.29
564	22.61	2.36	3.52
282	22.61	2.68	3.83
700	21.39	2.54	3.40
1,000	22.24	1.96	2.45
692	24.24	1.55	2.27
990	20.74	1.33	1.88
892	28.05	2.21	2.97
882	19.42	2.74	3.70
2,286	11.11	1.84	1.36
1,300	11.73	3.38	2.08
350	11.73	3.38	1.93
350	11.73	3.38	1.95
275	11.04	3.36	2.15
550	11.04	3.36	2.28
330	11.04	3.36	2.32
266	12.12	4.03	2.46
200	12.12	4.03	2.89
2,659	17.81	2.98	2.42
2,360	17.84	3.20	2.42
142	13.17	2.92	1.59
256	15.01[2]	3.75	2.07
1,214	13.17[2]	6.00	3.00
146	32.48[2]	2.04	1.53
960	27.71[2]	3.85	4.86
640	27.51[2]	3.48	4.38
350	30.86[2]	3.32	4.56
143	62.24[2]	4.46	2.60
1,500	19.87[2]	3.40	4.10
430	30.70[2]	3.50	4.82
960	$27.50[2]	3.74%	3.18%
350	29.14[2]	3.03	3.35
292	40.41[2]	3.55	4.06
670	27.46[2]	4.70	5.60
350	29.14[2]	3.48	6.12
430	81.00[2]	4.00	4.49
430	29.76[2]	3.26	4.56
215	28.84[2]	3.07	3.76
215	31.63[2]	3.41	4.30
700	18.35	1.91	1.70
500	21.34	1.52	2.34
500	17.58	1.47	1.35
88	17.43[2]	3.35	4.30
402	8.76[2]	2.08	2.08
156	9.45[2]	2.30	2.30
848	37.20	2.35	3.03
570	26.56[2]	2.22	3.00
845	26.20[2]	2.71	2.98
239	33.68	1.56	1.87
185	33.12	0.09	0.09
62	27.72	4.08	4.48
806	49.99	2.78	3.00
1,448	26.93	2.37	4.40
800	29.41	2.50	4.30
Total 42,974			

Site Capacity (Mw) (1)	Tower, Pump, Other Equipment Costs and Site Preparation Costs ($/Kw) (2)	Capability Losses[1] (Percent) (3)	Energy Losses[1] (Percent) (4)
	Natural Draft Cooling Towers		
2,240	$17.47	5.89%	3.70%
2,200	48.88	7.24	6.90
389	47.45	7.98	6.85
225	47.45	7.98	6.89
660	16.41	3.14	3.68
660	16.41	3.14	3.46
358	31.34	2.80	3.45
239	31.34	2.80	2.42
355	22.54	4.60	5.35
326	22.54	4.60	3.49
326	22.54	4.60	11.62
598	21.93	3.47	3.82
188	21.93	3.47	5.55
184	21.93	3.47	4.64
299	21.93	3.47	3.50
172	30.65	1.67	1.91
172	30.65	1.67	1.64
172	30.65	1.67	3.07
172	30.65	1.67	2.47
107	23.48	4.42	10.42
360	23.48	4.42	3.45
347	33.82	3.52	3.36
159	33.82	3.52	8.43
1,130	64.08	2.72	2.80
873	58.09	2.87	2.90
1,778	28.48	2.72	4.40
Total 14,689			

[1] Sum of losses from pumps, fans and back pressure.
[2] Excludes site preparation costs.

Weighted Average Mechanical Towers	$21.89
Weighted Average Natural Draft Towers	$33.33
Weighted Average for All Towers	$24.81

that site ($37 per kilowatt) would add about 1 mill per kilowatt-hour to the cost of electricity generated by that unit. Unusual compliance costs could impact the numerous small units or small systems more severely.

Flow Rate

The cost of closed-cycle cooling equipment and the total cost of generation are higher for units with higher flow rates, all other factors being equal. Flow rates for a particular unit can be reduced to some degree without significant incremental cost to achieve the reduced flow. In the cost analysis submitted to the Agency in support of the proposed subcategorization criteria, the cooling equipment costs for the cases of highest flow rate, all other factors being equal, were less than 10 percent higher than the average cost of all cases with various flow rates. Total generation cost were less than approximately 10 percent higher for the cases with the highest flow rates. In the cost analysis for the worst combination of intake temperature, wet-bulb temperature, and flow rate, the equipment cost exceeded the average equipment cost by 52 percent. These variations in equipment cost are within the range of variations in cost that are anticipated considering the numerous factors that combine, some favorably and some unfavorably, at each site to determine the final cost of thermal control implementation. A 10 percent cost differential is within the range of costs reflecting the normal variability among site-dependent factors in general as discussed above.

Intake Temperature

It is recognized that units with high intake water temperature will incur higher costs, all other factors being equal. This factor, however, is significant mainly during the months when the high intake water temperatures occur and also for those units for which high levels of blowdown flow are necessary, thus requiring relatively large quantities of makeup water. It is not as significant a factor for most units which require normal quantities of makeup water flow. In the cost analysis submitted to the Agency in support of the proposed subcategorization criteria, this factor all other factors being equal, added a maximum of 20 percent in the most extreme case to the average total thermal control equipment cost. This 20 percent cost differential is within the range of costs reflecting the normal variability among site-dependent factors in general as discussed above.

Wet-Bulb Temperature

The general cost analysis presented at the beginning of this section tested the significance of wet-bulb temperature costing various types of evaporative cooling systems considering four geographic locations representative of the range of wet-bulb temperatures in the United States. The cost of cooling equipment at the most unfavorable location based on wet-bulb temperature was 25 percent higher than the average cost of all locations tested for conditions otherwise identical. In the cost analysis submitted to the Agency in support of the proposed subcategorization criteria, this factor, all other factors being equal, added a maximum of 24 percent to the total thermal control equipment cost for the average of subcases covered for the most costly case analyzed. This 24 percent cost differential is within the range of costs reflecting the normal variability among site-dependent factors in general as discussed above.

Back-End Loading

The back-end loading of a unit is the maximum steam flow which the unit can pass through the last stage blades of the low pressure turbine expressed as a percentage of the maximum steam flow through the last stage blades which the turbine is capable of accepting.

In the cost analysis submitted to the Agency in support of the proposed subcategorization criteria, this factor, all other factors being equal, added a maximum of 22 percent to the total thermal control equipment costs compared to the average of the cases covered. The maximum cost reflected the cost for a unit with a back-end loading of approximately 15 percent. Generation costs in mills per kilowatt-hour for the worst case of a 15 percent back-end loading were estimated to be about 1 mill per kilowatt-hour. This 22 percent differential in equipment costs is within the range of costs reflecting the normal variability among site-dependent factors in general, as discussed above.

Aircraft Safety

An examination of this potential hazard indicated that it is unlikely that an existing powerplant which will be required to install a recirculated cooling water system would pose a hazard to commercial aircraft during periods of takeoff and landing. However, the vulnerability of aircraft during this portion of the flight pattern requires special consideration of cases where a substantial hazard may be shown to exist.

Miscellaneous Factors

Certain additional site-dependent factors have been suggested by commenters which should be considered in subcategorization for effluent limitations on heat because they can materially affect cost; existing system layout, soil conditions, site geology, and topography. While it is acknowledged that these factors may affect case-by-case costs, the costs attributable to these and other site-dependent factors have been assumed in the computation of the economic costs of thermal control.

Relative Humidity

Natural draft towers are limited for practical purposes to localities where the relative humidity exceeds approximately 50%. The lower humidities result in prohibitively tall towers to provide sufficient natural air flow through the tower.

Land Requirements

The land area for installation of cooling systems varies widely, as indicated on Table B-VIII-24. Obviously, cooling ponds will need large areas, and can only be considered where such land is economically available. The tower systems also require significant amounts of land.

The mechanical draft tower cell for medium size plants is on the order of 21 x 12 meters (70 x 40 ft). These cells are placed side by side to make up the tower, which can be as much as 183 m (600 ft) long, depending on capacity required. For a single tower installation, anywhere from 30 to 60 meters (100 to 200 feet) of clear area is required around the tower to avoid interference of surrounding structures on tower performance. This means that from 3 to 6 times the tower plan area is required. When two or more towers are necessary, the separation between towers must be 120 to 180 meters (400 to 600 feet) to avoid interference between towers. Total area required for two towers would be 4 to 7 times the tower plan area.

Reference 52 presents the following discussion of recirculation and interference as related to tower placement.

The problems most usually encountered on large mechanical draft industrial towers affecting the entering wet-bulb temperature are recirculation and interference. The former is a pollution of the inlet air by a tower's discharge vapors, and the latter is pollution of the inlet air by an

TABLE B-VIII-24

EFFLUENT HEAT

APPLICABILITY OF CONTROL AND TREATMENT TECHNOLOGY

Factor	Mechanical Draft Wet Cooling Tower	Natural Draft Wet Cooling Tower	Surface Cooling (Ponds, Canals, etc.)	Mechanical Draft Dry Cooling Tower
Size of Plant	No limitation	Greater than 500 Mw	No limitation	No limitation
Relative Humidity	No limitation	Generally limited to areas of the country having an average relative humidity of greater than 47%.	No limitation	No limitation
Land Area	70 ft. wide x 150 - 600 ft. long (depending on plant size); separation for multiple towers 400-600 ft.; clear area of 100 to 200 ft. required around perimeter of tower area.	350 - 550 ft. diameter plus 100 ft. open area around tower; nuclear plant-tower must be distance equivalent to height away from reactor; 1/3 reduction of land area possible with fan-assisted type tower.	1-3 acres per kwh of capacity depending on climatic conditions; use of spray modules reduces land requirement by approximately a factor of 10.	Higher than land requirements of mechanical draft wet cooling tower.
Drift	Current performance - less than .03% of circulating flow; anticipated improvement to less than .005%; potential problem in brackish or salt water areas.	Current performance - .005% of circulating flow; one tower under construction guaranteed to be less than .002%; potential problem in brackish or salt water areas.	Applicable only with use of spray modules; drift only in immediate area of pond, canal, etc.	None
Fogging	Potential local problem depending on location & climatic conditions; reduction of fogging possible with parallel-path wet/dry type tower.	Little anticipated at ground level.	Potential local problem depending on location & climatic conditions.	None
Noise	Potential problem only if adjacent to sensitive area; can be reduced by attenuation devices.	Less serious than mechanical draft towers, but still potential problem if very close to sensitive area; noise can be attenuated.	None	Potential problem only if adjacent to sensitive area; can be reduced by attenuation devices.
Height	No limitation	350-600 ft.; potential aviation problem in specific locations; comply with FAA restrictions.	No limitation	No limitation
Water Consumption	Up to 0.7 gallons per kwh produced.	Up to 0.7 gallons per kwh produced.	Up to 1.1 gallons per kwh produced; includes natural evaporation from surface.	None
Energy Requirements	Fan power - 5-13 Mw per million GPM of circulating water; pumping power - 7-12 Mw per million GPM of circulating water.	Pumping power - 10-15 Mw per million GPM of circulating water; no fan power required.	Pumping requirements vary with plant conditions; spray modules generally 75 HP per unit.	Total power requirement - .02-.08Mw per installed Mw capacity.
Max. Wind Velocity	No limitation	Current design -120mph @ 30ft. elev.	No limitation	No limitation
Foundation Requirements	Greater than 3000 psf soil bearing value or equivalent with piles.	Greater than 6000 psf bearing value or equivalent with piles.	No limitation	Greater than 3000 psf soil bearing value or equivalent with piles.
Turbine Back Pressure(Present units limited to 5 in. Hg)	Applicable to all plants;penalty for operation at back pressure above original design.	Generally applicable only to plants above 500 Mw ; penalty for operation at back pressure above original design.	Applicable to all plants; penalty for operation at back pressure above original design.	Not applicable to existing plants; results in back pressure of 8-15 in. Hg during summer months; new plants will require turbine re-design.
Aesthetic Considerations	Visual plume.	Visual plume; size and height.	No limitation	No limitation

adjacent tower or other heat source. These problems are nonexistent on hyperbolic towers because of the height of vapor discharge.

The magnitude of recirculation is dependent primarily upon wind direction and velocity, tower length, and atmospheric conditions. Other factors are fan cylinder height and spacing, exit air velocity, tower height and the density difference between exit air and ambient air.

A longitudinal wind tends to carry discharge vapors along the tower and the first few cells will not be seriously affected. However, from the initial downwind point of entry into the louver face or faces, the effect of recirculation becomes increasingly severe along the length of the tower. Therefore, as tower length increases, the more damaging a longitudinal wind can become.

A broadside wind causes no recirculation on the windward side of the tower. Recirculation is greatest towards the midpoint on the leeward side. It diminishes towards the ends because of fresh air flow around the ends of the tower. High stacks and maximum space between stacks serve to reduce the broadside recirculation effect in proportion to the ratio of this free space area to the lee side louver area of the tower.

It is apparent that recirculation is primarily a function of tower length. Normally, placement of single towers with ambient winds in a longitudinal direction is recommended for tower lengths up to 200 to 250 feet. For tower lengths greater than this, more rigorous study of the aforementioned factors affecting the circulation is required to determine the most suitable orientation. When tower length exceeds 300 to 350 feet, strong consideration should be given to splitting into multiple units. The problem then becomes more a matter of locating the units to minimize interference.

The principal objective in arranging a multiple tower installation is to orient the units for minimum recirculation within themselves and minimum interference between each other, particularly during the high capability requirement periods. No set rules can be given for orientation of multiple units, but generally, it can be stated that as the number of units increases, the broadside arrangement tends to be more favorable than longitudinal. Each installation should be analyzed for orientation within the prescribed real estate limitations with respect to the following factors: (1) number of towers in system, (2) number of cells per tower, (3) cell length and height, (4) height and spacing of stacks, (5) discharge air velocity and density, (6) ambient atmospheric conditions, and (7) prevailing wind rose for high wet-bulb hours. See Figures B-VIII-20, and B-VIII-21 for possible broadside and longitudinal multiple tower orientations.

The natural draft tower, which varies in diameter from 108 to 168 meters (350 to 550 feet) normally requires a clear area 30 m (100 feet) wide around it perimeter to allow for construction. This amounts to a land area twice the plan area of the tower. For nuclear units, the tower must be separated from the reactor buildings by a distance equal to its height.

If land space is restricted, any number of solutions may be used. Rearrangement of mechanical draft towers to fit space, or use of a mechanical draft tower of a different configuration, such as round, might be used. Natural draft towers might require less land. A single large tower might take the place of two smaller, more economical ones. The fan-assisted natural draft tower appears to be a system with minimum land requirements. One existing plant, located in an urban area, is installing one of these towers in a former parking lot. An analysis of land estimated to be required for evaporative cooling towers at eight nuclear plants indicates that 20 acres/1000 megawatt generating capacity would be the maximum amount required.

The Federal Power Commission, National Power Survey (1964) puts the land requirement for mechanical draft evaporative towers at 1,000 to 1,200 square feet per megawatt including area required for spacing. Furthermore, natural draft evaporative towers would require 350 to 400 square feet per megawatt. For a 1,000 megawatt capacity tower requiring 1,200 square feet per megawatt, approximatley 28 acres of land would be required.

Land requirements reported by other sources for various cooling methods are summarized by Reference 385 as follows:

Cooling Ponds	1000-3000 acres/1000Mw
Jet Spray Ponds	50- 300 acres/1000Mw
Natural Draft Wet Towers	4- 5 acres/1000Mw

Due to the variations in heat rate, climatic factors, etc. from site-to-site, 28 acres per 1,000 megawatts generating capacity should be sufficient land for any plant to apply closed-cycle evaporative cooling towers. In many cases where less than this amount of land is available, it would

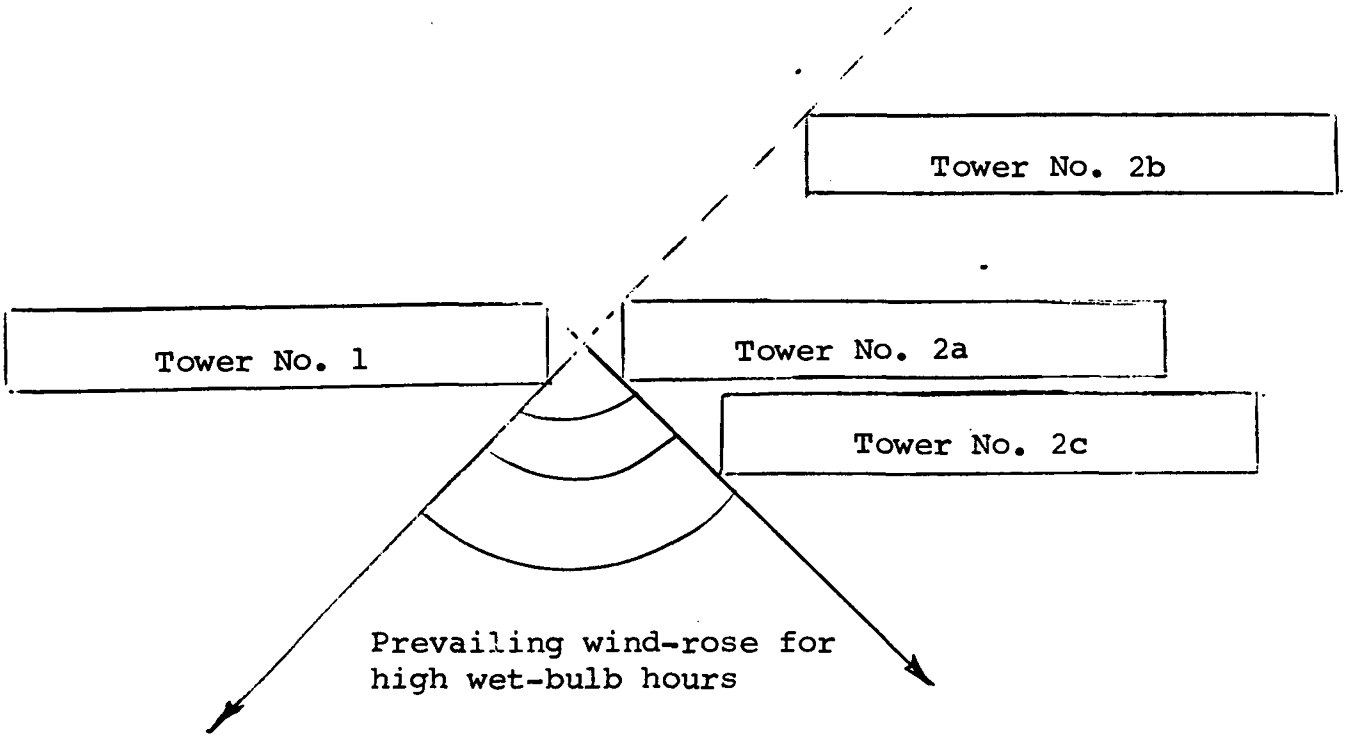


Figure B-VIII-20
BROADSIDE MULTIPLE TOWER ORIENTATION

Tower No. 2 placed typically in location a,b, or c
relative to Tower No. 1 and the wind-rose

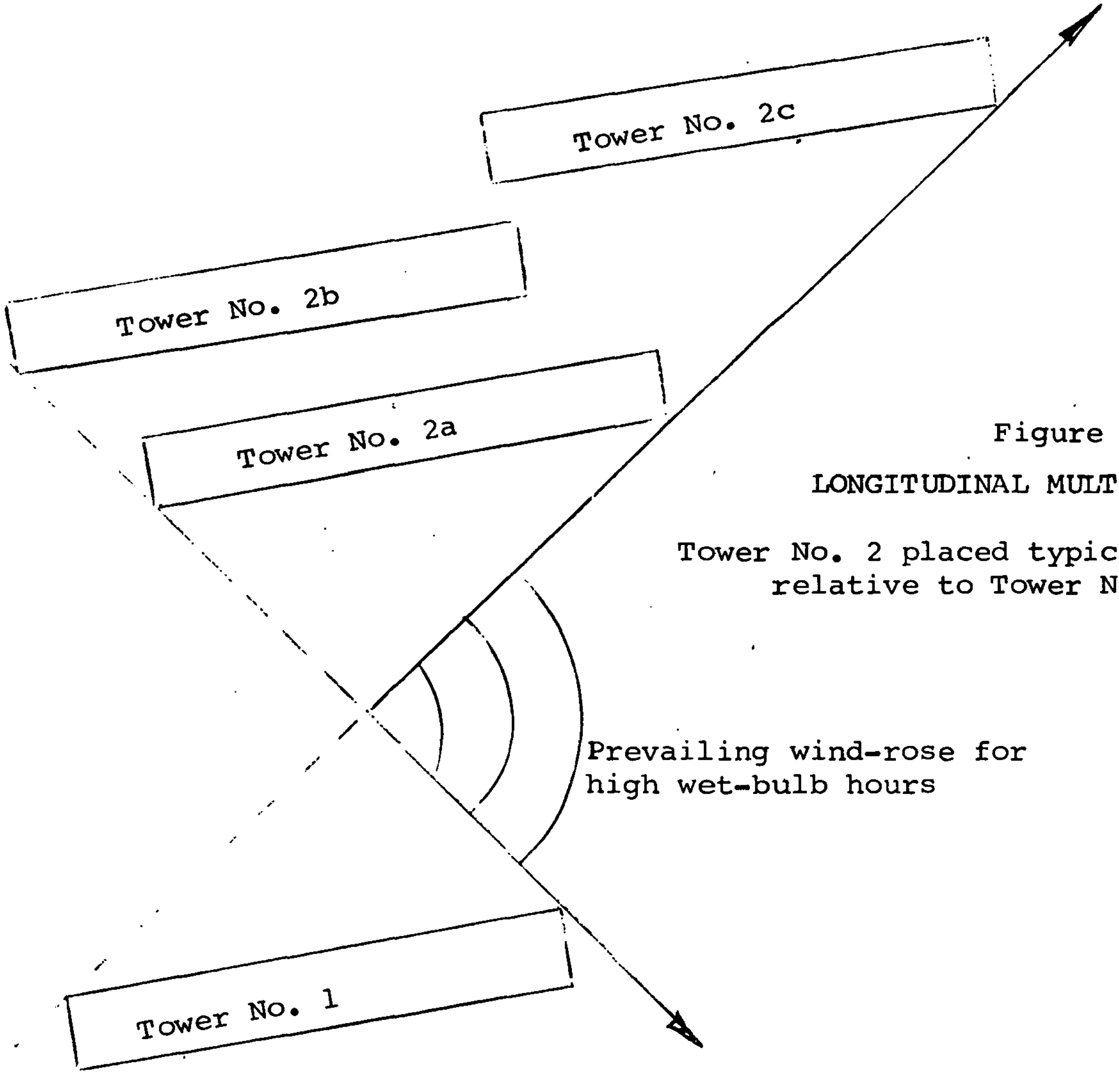


Figure B-VIII-21

LONGITUDINAL MULTIPLE TOWER ORIENTATION

Tower No. 2 placed typically in location a,b, or c relative to Tower No. 1 and the wind-rose still be practicable to apply evaporative cooling towers due to the conservatism of the 28 acres per 1000 megawatt assessment and, further, due to the possible practicability of natural draft or other systems at the site. Many plants which do not have land immediately available for evaporative cooling systems could make sufficient land available by shifting, to some degree, present uses of land at the site and by acquiring the use of neighboring land. Land requirements for other uses would depend on the types and relative amounts of fuel, method of ash disposal, and other factors in addition to plant generating capacity.

Reference 370 addresses the land requirments for projected 3,000-megawatt plants as compared to 1,500-megawatt plants. The land required for a powerhouse containing three 500-megawatt units is in the range of 3 to 4 acres; for three 1,000-megawatt units the range is 6 to 7 acres. These figures include the service bay, but not space for equipment and facilities outside the powerhouse. Electrostatic precipitators, stacks, walkways, drives, and parking areas immediately adjacent to the powerhouse would be about 2-3 acres for three 500-megawatt units and 6-7 acres for three 1000-megawatt units. Sulfur dioxide removal equipment would add as much on 2-4 acres. Coal-fired plants require inactive coal storage in an amount to supply 45 - 120 day's burn at the total plant capacity. A typical coal-storage yard to provide 90 days supply at a 3,000-megawatt plant would require 40 acres and the coal pile would be 40 feet high. The switchyard area requirements for a typical 3,000-megawatt plant with 500-kv transmission voltage would be in the range of 10-15 acres. The transmission lines connecting a typical 3,000-megawatt plant with the existing transmission system at 500 kilovolts would occupy rights-of-way of from 100 to 150 acres per mile. On-site ash disposal for a 3,000-megawatt coal-fired plant (assuming 35 year useful life and 50% capacity factor) would require 300 to 400 acres with ash piled to a depth of 25 feet to store all the ash developed during the life of the plant. Limestone-injection systems for controlling sulfur dioxide emissions would double or triple the volume of ash produced while the system is in operation. In some cases off-site disposal of ash would be an available alternative to on-site disposal.

Other facilities that would require significant amounts of land include rail, barge and truck terminals for coal-fired and oil-fired plants, oil storage for oil-fired plants, and an exclusion area for nuclear plants. In summary, a 3,000-megawatt plant would require, if coal-fired, 200 to 1200 acres, nuclear 200-400 acres, oil-fired 150-350 acres, and gas-fired 100 to 200 acres, assuming on-site storage of coal and oil, pipeline delivery of gas with some on-site storage, and on-site coal-ash disposal.

In spite of the ingenuity of the cooling tower engineer, there may be a significant number of units or plants where addition of a cooling tower would not be practicable. In the case of a plant in a location where the surrounding land is already highly developed, the cost of available land may be high, and it might be necessary to remove any existing structures from the land, once it was purchased. Secondary effects, such as fogging or drift could result in complaints from surrounding neighbors, as well as a requirement to repair resulting damage. Noise levels from the tower might be unacceptable to the neighbors. The number of plants located in the 50 largest metropolitan areas amounts to some 15% of the total (see Table IV-3). An equal number are probably located within the city limits of small towns, particularly in the Great Plains states. The practicality of installing cooling towers will depend on the local conditions at each plant. One may be surrounded by high rise buildings, while the next may be adjacent to a vacant city block. Another plant may be in a heavy industrialized area, whereas another would be in a semi-residential area where the tower noise aspect may be more sensitive. Land values will vary greatly, from possibly $25,000 per ha ($10,000 per acre) in small towns to $2,500,000 per ha ($1,000,000 per acre) in the center of a large metropolitan area.

In a case where 28 acres would need to be acquired for cooling towers at a 1000 Mw plant, at $36,000 per acre, the added land cost of $1,000,000 would be less than 5% of the other capital costs of the towers at $22/kw ($22,000,000).

Reference 446, reporting results of a survey of utilities concerning land availability for cooling towers and other factors, found that sufficient land was considered to be available in 75% of the plants sampled.

Nuclear plants would not normally be seriously affected by land area limitations for two reason. They are not located in metropolitan areas, and the required exclusion area normally provides sufficient area for cooling system installation unless topographic conditions are unfavorable. However, when a nuclear plant goes from open to closed system cooling, the low-level radwaste system normally needs to be upgraded. With the open system, low-level radwastes are added to the circulating water for dilution to meet standards for the discharge of radioactive materials. The blowdown stream may not be sufficient for dilution, forcing installation of a new low-level radwaste system. Cost of this has been estimated to be several million dollars at one nuclear plant.

Non-Water Quality Environmental Impact of Control and Treatment Technology

The potential non-water quality environmental impacts which could influence the type of system selected or which must be minimized in certain cases include these listed below.

1. Drift, resulting in salt deposition on surrounding areas.

2. Fogging, visual impact and safety hazards.

3. Noise levels unacceptable to neighbors.

4. Height, creating aviation hazards.

5. Water consumption by evaporative systems.

6. Aesthetic considerations, visual impact of cooling device.

The influence of the majority of these factors on the selection and cost of the installation of these cooling systems is summarized in Table B-VIII-24, with a detailed discussion below of some of the factors not discussed elsewhere in this document.

Drift

Water vapor and heated air are not the only effluents from a cooling tower. Small droplets of the cooling water become entrained in the air flow, and are carried out of the tower. These drops have the same composition as the cooling water, i.e., they contain the same concentration of dissolved solids and water treatment chemicals. The water may evaporate from the drops, leaving the solids behind, or the drops may impinge upon the surrounding structures or terrain. The chemicals and dissolved solids add a chemical load to the air and surrounding terrain that must be taken into account.

Some data on estimated solids in drift from cooling towers are shown in Table B-VIII-25. This was taken from the final environmental statements for a number of nuclear stations. There is obviously a large variation in the assumed drift rates. All these values are mentioned in the literature, with the lower values the more recent. Another factor is the concentration of solids in the drift. It is obvious that the proposed towers at Plant no. 1209, operating on sea water, will have a higher solids loss through drift, as indicated in Table B-VIII-25.

The amount of drift from any tower is primarily a function of the tower design, and the drift eliminators in particular. The total losses to drift are normally expressed as a percentage of the flow through the tower. Until recently, drift losses of less than 0.2% were guaranteed.[140] Now cooling tower manufacturers are guaranteeing much lower drift losses. Losses of 0.02% are considered high. Several new towers have been awarded based on drift guarantees in the range of 0.002 - 0.005 percent of cooling water flow. A number of tests, summarized in a report for EPA by the Argonne National Laboratory,[286] showed that drift from mechanical-draft towers averaged 0.005%, while that from natural-draft towers might average half of that, or 0.0025%. With a 0.01% drift eliminater, an estimated 1 ton of salt per day would be deposited downwind of a 1,000 megawatt nuclear unit.

While better design is partially responsible for the lower drift rates, better measurement techniques are equally, if not more important in establishing drift rates. With the older, less sophisticated methods, manufacturers were less sure of the actual drift rates, resulting in high rates for guarantees.

With the greater emphasis on environmental protection, it became necessary to measure drift more accurately to determine the amount of solids leaving the tower to end up as fallout on the surrounding terrain or suspended in the atmosphere. Currently at least two systems are available. The first, the Pills System, is for continuous monitoring of drift. The second is a system for sampling the drift intermittently.

The Pills (Particle Instrumentation by Laser Light Scattering) system is an electro-optical system for monitoring the drift.

The intermittent sampling system is an isokinetic device. The discharge air is sampled at its natural flow velocity as

TABLE B-VIII-25
SOLIDS IN DRIFT FROM COOLING TOWERS

Plant No.	Size Mw	Cooling System (Type)	Drift (% Flow)	Solids in Drift	
				lbs./yr.	lbs/kwh (installed) $\times 10^3$
1209	1320	Mech. Draft (salt water)	0.1	3.8×10^7	3.3
1311	1644	Mech. Draft	0.2	6×10^5	.042
3608	873	Nat. Draft	0.0025	1.1×10^6	.14
6506	850	Nat. Draft	.01	4.0×10^5	.054
3940	872	Nat. Draft	.01	9.0×10^4	.012
0109	1722	Mech. Draft	.01	10.5×10^5	.070
3635	821	Mech. Draft	.005	4.7×10^4	.0065

implied by the term "isokinetic". One device uses a sampling tube filled with warmed glass beads. A vacuum system pulls the sample into the tube where the drift impinges on the glass beads. The moisture evaporates, leaving the solids behind. Weighing of the sample tube determines the solids collected. This, plus a knowledge of the solids contents of the water, permits calculation of the amount of drift. This device supersedes a number of isokinetic devices considerably more cumbersome, and of doubtful accuracy.

Drop size is another problem. Sensitive paper, and more recently, the Pills system[140] are used to measure drop sizes of 100 micron or larger. Several tests by one manufacturer indicate that the drops accounting for 85% of the mass of the drift have diameters greater than 100 microns, with less than 1% over 500 microns.

The drift from cooling towers, mechanical draft in particular, potentially can create serious problems, depending on the salts and chemicals in the cooling water. Drift coating insulators on the transformers and switchyards can possibly lead to leakage and insulator failure. Corrosion of metallic surfaces, deterioration or discoloration of paint and killing of vegetables have been noted. Thus, the minimization of drift is an important design feature of the cooling tower.

The use of brackish or seawater in cooling towers aggravates the drift problem due to the high concentration of salt in the water. Fifteen saltwater cooling towers are in use or planned for steam electric powerplants. Numerous factors affect the dispersion and deposition of drift from these towers (See Table B-VIII-26).[385] Proper location of the towers with respect to the plant buildings and switchyards can avoid most of the problems encountered with highly saline drift. The rate of drift fallout is related to the distance from the tower. (See Figure B-VIII-22). This is particularly true for mechanical draft towers which discharge at relatively low levels.

Although the environmental effects of saltwater cooling towers vary from case to case depending on the sensitivity of local environment and diverse local meteorological conditions, experience with existing salt water cooling towers indicates that environmental problems would be confined to areas in close proximity to the cooling tower. One study (Reference 451) showed that about 70 percent of all drift mass fell within 400 feet downwind of a typical saltwater mechanical draft tower, well within the boundaries

Table B-VIII-26

FACTORS AFFECTING DISPERSION AND DEPOSITION OF DRIFT FROM NATURAL-DRAFT AND MECHANICAL-DRAFT TOWERS[385]

Factors associated with the design and operation of the cooling tower	Factors related to atmospheric conditions	Other factors
Volume of water circulating in the tower per unit time Salt concentration in the water Drift rate Mass size distribution of drift droplets Moist plume rise influenced by tower diameter, height and mass flux	Atmospheric conditions including humidity, wind speed and direction, temperature, Pasquill's stability classes, which affect plume rise, dispersion and deposition. Tower wake effect which is especially important with mechanical draft towers Evaporation and growth of drift droplets as a function of atmospheric conditions and the ambient conditions Plume depletion effects	Adjustments for non-point source geometry Collection efficiency of ground for droplets

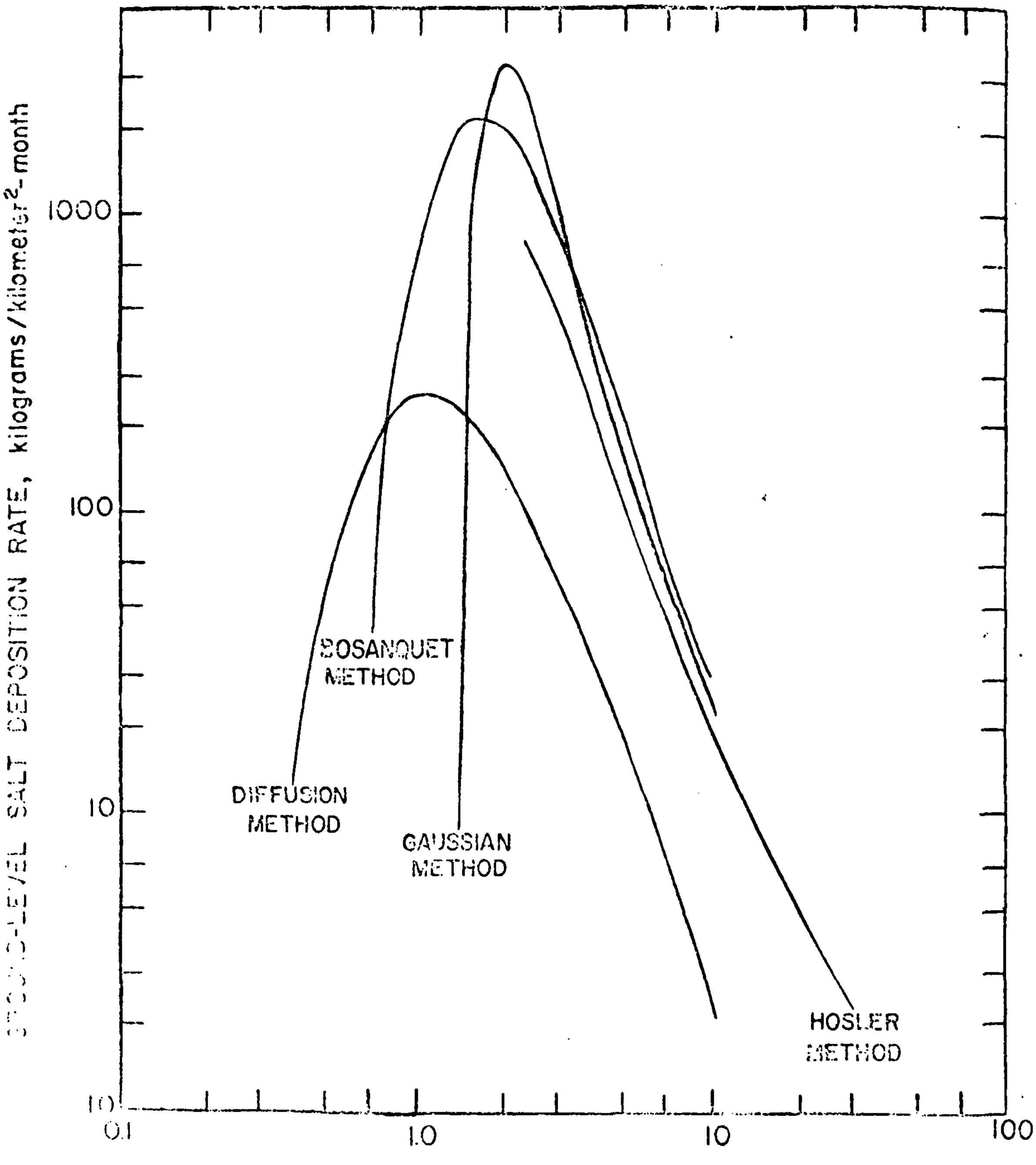


Figure B-VIII- 22

Ground-Level Salt Deposition Rate From A Natural-Draft Tower As A Function Of The Distance Downwind. A Comparison Between Various Prediction Methods[385] of most powerplants. The same study showed that even under the most adverse conditions, all drift droplets that would reach the ground would do so within 1,000 feet downwind. The subject of this study was a hypothetical eight-cell crossflow mechanical draft tower designed to cool 134,000 gallons per minute of water with the same chemical composition and salinity as seawater. The plant was assumed to be located on an estuary or bay, two miles from the ocean. The drift rate was 0.004 percent of the circulating water.

Airborne drift from this tower plus natural background salt nuclei from the sea exceeded conservative damage thresholds for foliar injury for distances up to 2,200 feet downwind of the tower. The background salt nuclei contributed over 75 percent of the salt mass causing damage at this distance from the tower. Moreover, the fractional increase in airborne salt concentrations due to drift at 2,200 feet was insignificant as compared with normal variations in the background level caused by changes in atmospheric wind conditions.

Obviously, local plant life in areas potentially affected by salt drift from towers must be capable of withstanding these natural airborne salt levels if they are to survive. Other possible recipients of . incremental salt drift would likewise be affected by the natural ambient levels.

The additional cost of drift eliminators does not represent a significant increment to total cooling system cost and should be reflected in the cost estimates supplied by the industry for plants representing over 12 percent of the Nation's total generating capacity.

Wistrom and Ovand[363] concluded, from their study of field experience during the last 20 years where salt or brackish water has been used in cooling towers, that "cooling tower drift effects in the environment are localized and that beyond same reasonable distance that is usually within the plant site boundary, drift does not significantly affect the environment".

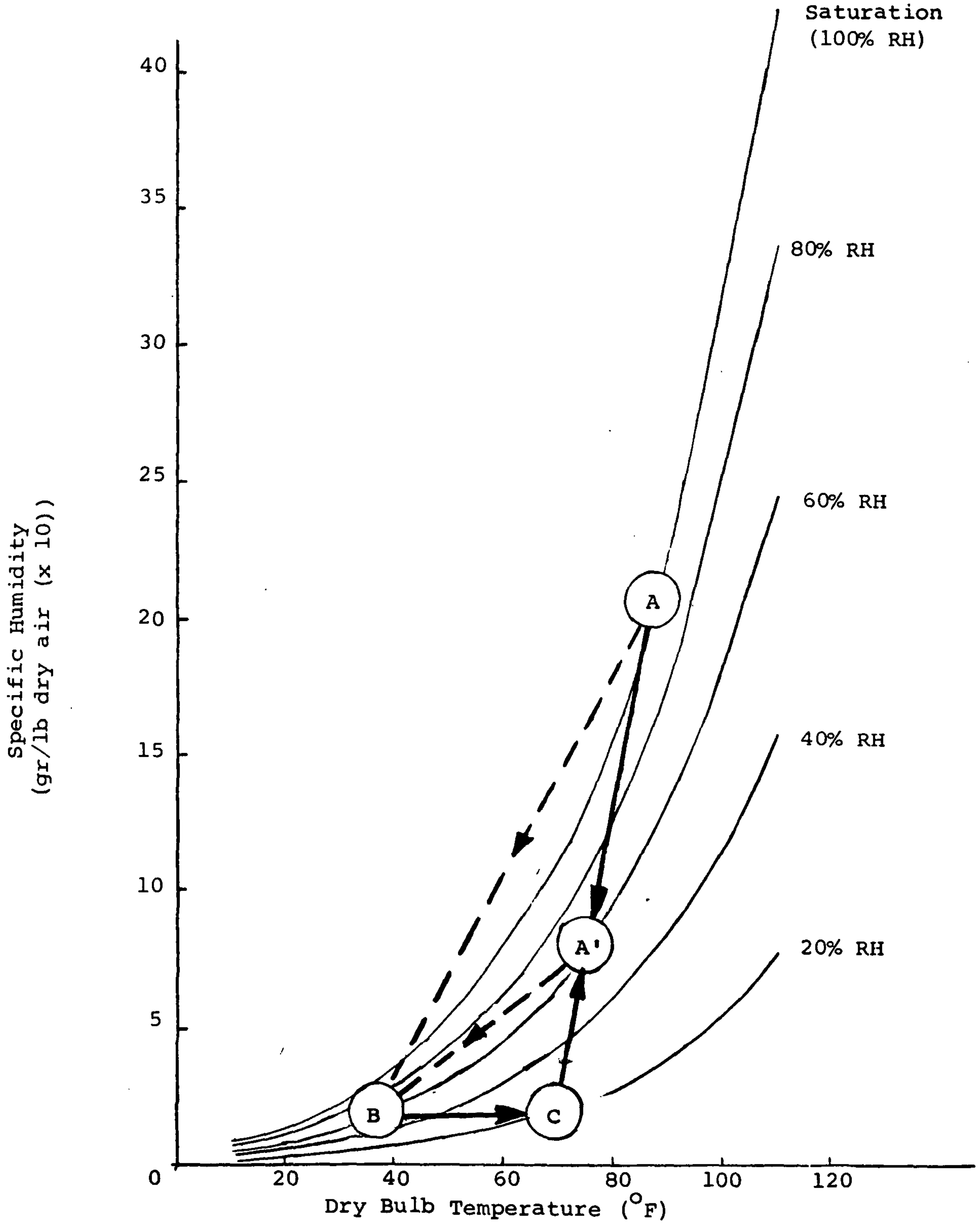
The fact remains that this salt will be deposited on the surrounding terrain. Whether or not this influences the environment, i.e., vegetation and ground water salinity, will depend on the increase over the natural deposition of salt on the surrounding terrain. The natural salt load, particularly along ocean coasts exposed to continual wave action, can be fairly high. If the tower drift results in a salt load of only a few percent of this natural salt deposition rate, the effect would probably be minimal.

A summary of the state-of-the-art of saltwater cooling towers (Reference No. 385) concluded that "although the environmental effects of saltwater cooling towers vary from case to case depending upon the sensitivity and diversity of local conditions, experience with existing salt water cooling towers indicates that the environmental problems would be confined up to several hundreds meters from the cooling tower." Environmental impact on the biota, bodies of fresh water, soil salinity and structures is difficult to detect at the levels of the long-term average in coastal areas. The direct experimental data available about the environmental effects are sparse. Most of the environmental impact predictions are based upon research studies pertinent to the coastal environment, which may or may not be applicable for salt water cooling towers in other locations. Most of this available information is descriptive in nature and does not permit a correlation between the airborne salt concentration or deposition rate and environmental effects."

Adverse environmental impacts due to drift are not a national-scale problem. Technology is available to integrate a low drift requirement into the overall tower design at moderate cost. In addition, alternate cooling systems selection and proper location of the tower with respect to prevailing winds and surrounding land uses can also be used to meet stringent drift requirements. New plants have the additional flexibility of site selection to help minimize this problem.

Fogging

Fogging is one of the most noticeable of the possible side effects of the use of evaporative cooling devices. Fog is produced when the warm, nearly saturated air from the cooling facility mixes with the cooler ambient air. As the warm air becomes cooler, it reaches first saturation, then supersaturation with respect to water vapor content. When this occurs, the vapor condenses into visible droplets, or fog. The psychrometric chart in Figure B-VIII-23 shows representative conditions through which the air-water mixture can pass to create fog. The condition at point B is that of the ambient air. As this air leaves the tower, (point A) it mixes with the colder, less humid ambient air following the dotted line which lies largely in the portion of the chart which represents a condition where the air contains more moisture than it can contain at 100% saturation. In this condition condensation can occur,



MODIFIED PSYCHROMETRIC CHART
(From Reference 128)
FIGURE B-VIII- 23

producing fog although normally some supersaturation is necessary. As more mixing occurs, the air condition eventually returns to point B.

The development of fog by cooling devices is primarily dependent on the local climatic conditions. The areas normally susceptible to cooling tower fog are those in which natural fogs frequently occur. EG & G, Inc. in a report for EPA, [219], defines three levels of potential for fogging, as listed below.

a. High Potential: Regions where heavy fog is observed over 45 days per year, where during October through March the maximum mixing depths are low (400-600 m), and the frequency of low-level inversions is at least 20-30%.

b. Moderate Potential: Regions where heavy fog is observed over 20 days per year, where during October through March the maximum mixing depths are less than 600 m, and the frequency of low-level inversions is at least 20-30%.

c. Low Potential: Regions where heavy fog is observed less than 20 days per year, and where October through March the maximum depths are moderate to high (generally greater than 600m).

Using this criteria and several meteorological references, EG&G has developed the map shown in Figure B-VIII-24, indicating the fogging potential of locations within the United States.

The length of the expected fog plume can be estimated from the following equation: [95]

$$Xp = 5.7(Vg)^{0.5} (320Vw)^{-0.5} (Tge-Tgi)^{0.5} (Tp-Tgi)^{-0.5}$$

Where Xp = visible plume length, ft

Tg = air or plume temperature, °C

Tp = temperature at end of visible plume, °C

Vw = wind speed, ft/sec

Vg = total rate from tower cu m/hr (gas evaluated at 20°C)

i = tower inlet

e = tower exit

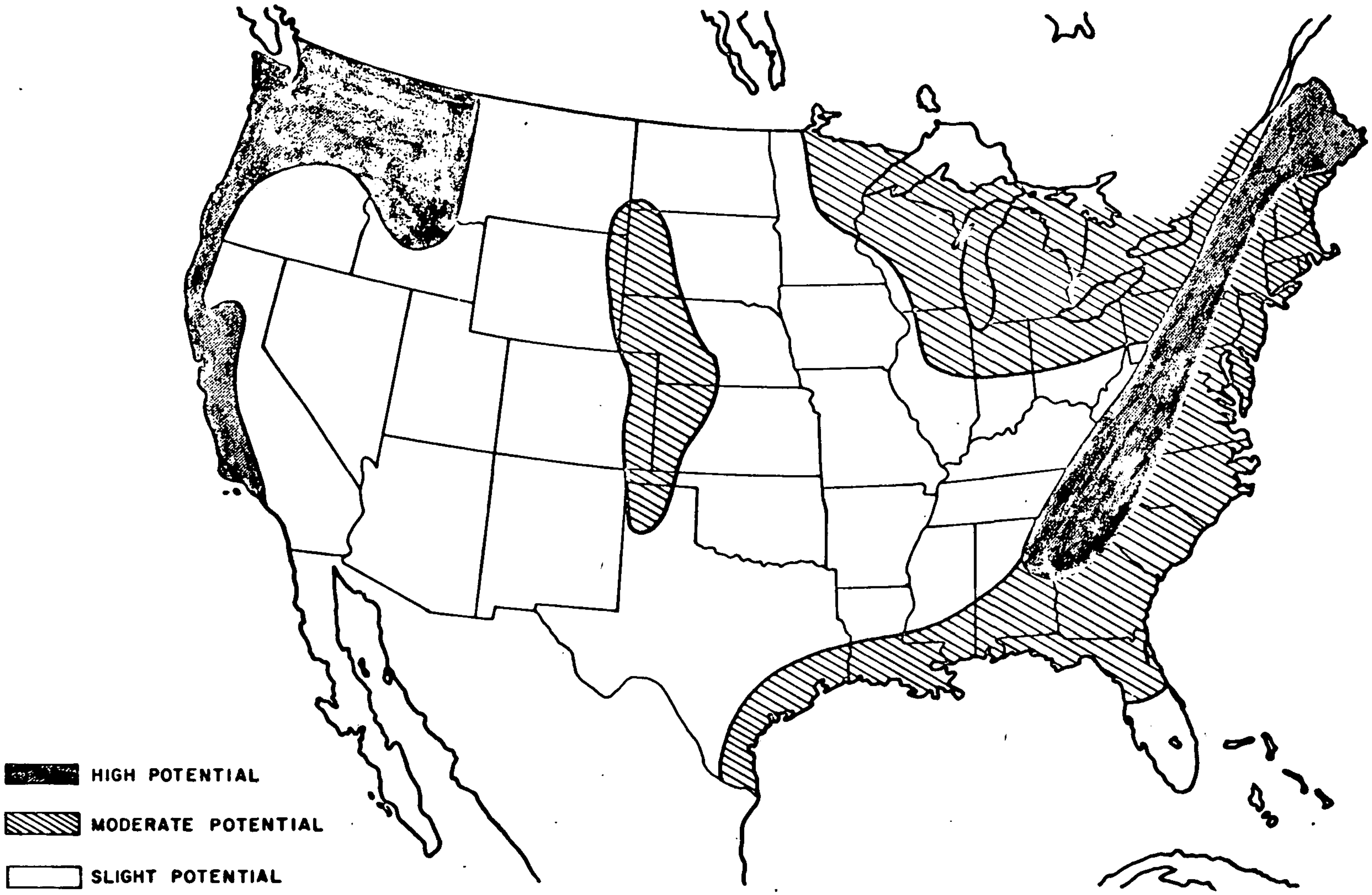


Figure B-VIII-24

GEOGRAPHICAL DISTRIBUTION OF POTENTIAL ADVERSE EFFECTS FROM COOLING TOWERS, BASED ON FOG, LOW-LEVEL INVERSION AND LOW MIXING DEPTH FREQUENCY.

(From Reference 219)

In order for fogging to create an impact it most exist in close proximity to a land use with which it interfers such as a major residential, commercial or industrial activity. As can be seen from Figure B-VIII-24, most of the major U.S. residential, commercial and industrial centers do not lie in the areas of high fogging potential.

Furthermore, local meteorology and the configuration of the source and its surroundings must permit a downwash condition to obtain fogging. These will not usually exist if the cooling tower if properly designed and located.

In view of these factors a conservatively high estimate of the plants that would be concerned with fogging problems resulting from the installation of closed cooling systems is less than 5 percent of the total plants. Moreover, fogging would only be of concern at the plants for small fractions of the total operating time,

The fog plume from a mechanical draft tower is emitted close to the ground, and under appropriate conditions, can drop to the ground. Under these conditions the fog can create a serious hazard on nearby highways. If the fog passes through the switchyard, insulator leakage problems can be encountered. Thus, in addition to being highly visible, the fog plumes create safety hazards and accelerate equipment deterioration. Careful placement of the towers will eliminate most of the problems. If placement is unsatisfactory, or creation of hazards is still expected, the use of a wet-dry tower can significantly reduce the plumes. In the wet-dry tower (typically) ambient air is heated from point B (See Figure B-VIII-23) to point C in the dry section. Air from the wet section (point A) and dry sections are mixed and exhausted at a condition represented by point A¹. In mixing with ambient air (dotted line) subsaturated conditions exist and fogging cannot occur. Two towers of this type are currently on order or under construction for large generating plants in the U.S. It should be noted ,however, that this type of tower is more costly than the conventional wet-type tower (approximately 1.3 to 1.5 times the cost of a conventional tower). This would add an increment of approximately 0.15 mills/kwh for plume abatement for a large, modern base-load unit. While wet-dry towers are more costly than conventional wet towers, the cost of employing plume abatement in specific cases has been accounted for in the general analysis of the cost of cooling tower construction. The general analysis is based on cost data supplied by industry, which were, in turn, developed from a sample of 60 plants and units and the costs for 18 of the units in the sample reflected the use of wet-dry towers.[447] Other possible techniques of plume abatement include increasing the mechanical draft stack height, heating tower exhaust air with natural gas burners, installing electrostatic precipitators or mesh at the tower exit, and spraying chemicals at the tower exhaust.

Another possible solution is to use a natural-draft tower. The plumes from these towers are emitted at altitudes at 90 to 150 meters (300 to 500') above the tower ground level, and there is little possibility of local fog hazards, as the plume is normally dispersed before it can reach the ground. One hazard that might arise would be to aircraft operation, although plumes are normally localized. The use of natural draft cooling towers in high potential fog areas seems to be an accepted practice, as indicated in Figure B-VIII-25 [283], which shows the location of 75% of the natural draft towers expected to be constructed through 1977. Note that the majority of them are in the eastern area of high fog potential. Under freezing conditions the fog may turn to ice upon contacting a freezing surface. The ice thus formed is commonly called rime ice. This is a fragile ice, and breaks off the structure before damage occurs from the additional weight, except on horizontal surfaces. Here again, although it is mentioned in the literature, the problem is considered to be insignificant.

The potential for modification of regional climate exists, but has not been verified to date. The Illinois Institute of Technology Research Institute in its report [283] for EPA on the field tests at Plant no. 4217 in Pennsylvania determined that the effects were minimal. This plant evaporates approximately 0.63 cu m/s (10,000 gpm) of water and releases approximately 0.5 x 10^6 kg cal/s (120 x 10^6 Btu/min) of heat to the atmosphere when operating at 1440 Mw, 80% of its design capacity. Two natural draft towers are installed at Plant no. 4217. A review of weather station records at stations located 13 to 51 kilometers from the plant resulted in "a suggestion of precipitation enhancement". Initiation of cloud cover occurred rarely, and only preceded natural development of cloud cover. The cooling tower plume would merge with low stratus clouds when they were at an appropriate elevation.

The current "state-of-the-art" in meteorology has not progressed to the point where the effects of large thermal releases to the atmosphere can be quantitatively evaluated.

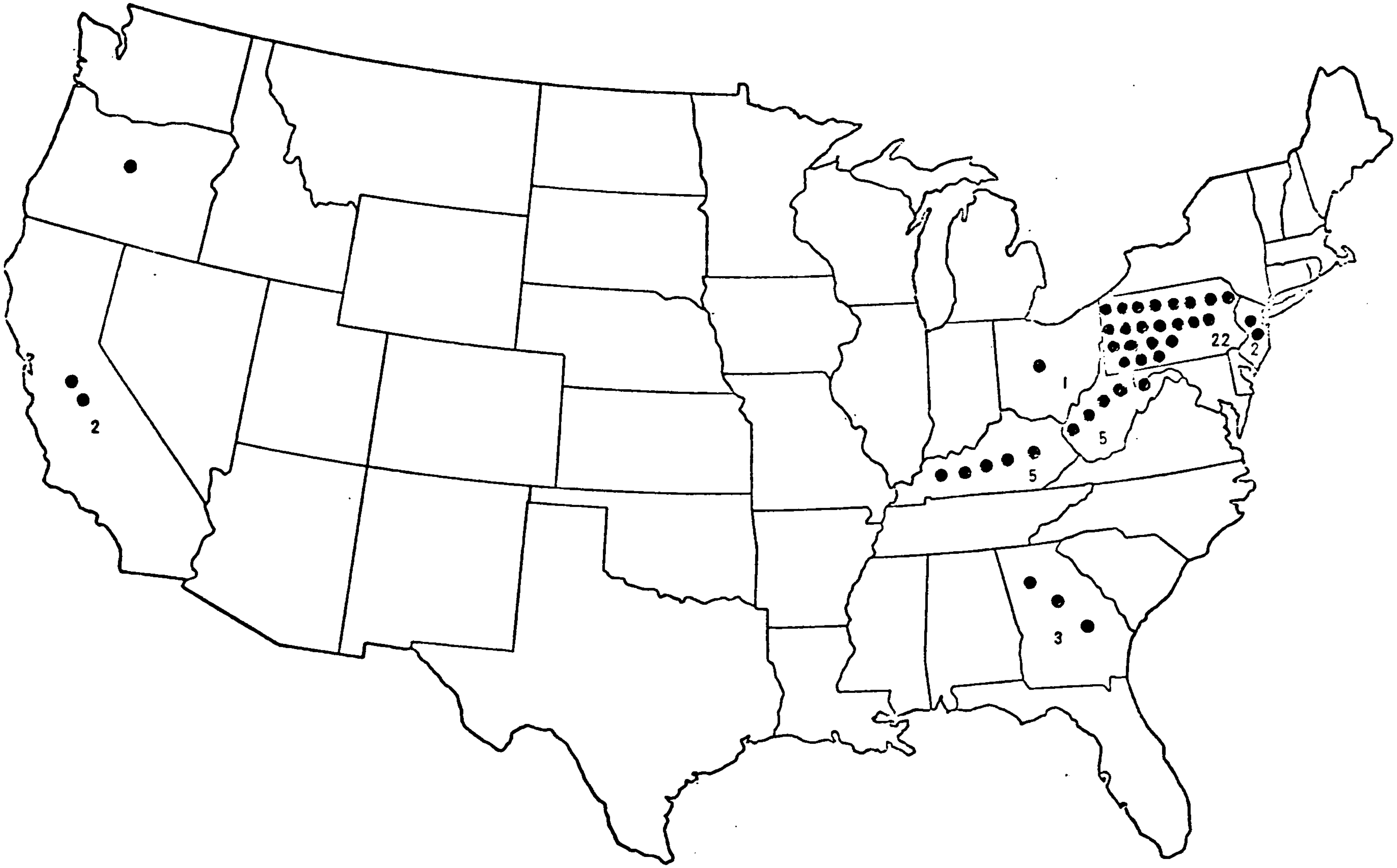


Figure B-VIII-25
LOCATION OF NATURAL DRAFT COOLING TOWERS THROUGH 1977
(From Reference 283)

Improvements in meteorological techniques currently in progress will undoubtedly result in quantification of these effects. A number of meteorologists indicate that thermal emissions to the atmosphere could have significant effects on mesoscale phenomena, where mesoscale refers to a scale of from 1 to 50 kilometers. A comparison of some natural and artificial energy production rates is shown in Table B-VIII-27.[367] It is obvious that some of our artificially produced energy rates are equal in magnitude to those of concentrated natural production rates.

It is possible that these thermal discharges may have a "triggering" effect on a much larger phenomena, such as thunderstorms, tornados, or general cloud development and precipitation. This could prove beneficial if the triggering could be adequately controlled, and possibly disastrous if control was not possible.

Although no regional climatic changes have been noted to date, this does not mean the possibility does not exist. With larger and larger stations being built which reject their heat to the atmosphere through wet cooling towers, it becomes evident that this water must be added to the rainfall at some location, wherever it may be, and that the additional heat will influence the climatic conditions to some extent. This probably falls into the category of weather modification, even though it be unintentional, and is currently being investigated by meteorologists.

With coal-fired or oil-fired plants, there is an additional factor in relation to plumes. The stack gases of these plants contain varying amounts of SO_2, depending on the sulfur content of the fuel used and the degree of flue gas desulfurization achieved. To the extent that the stack gases and the cooling tower fog plume became intimately intermixed, the fog will interact chemically with the SO_2, forming sulfuric acid. This is a corrosive acid, and settlement on surrounding buildings will accelerate deterioration. Vegetation will also be affected by this "acid fog". The relationship between the two discharges should be such as to minimize their intermixing.

In addition to the basic meterological considerations, two other factors should be considered where stack and cooling tower plume intermixing must be minimized, as follows: (1) location of the cooling towers in relation to the stacks, and (2) the buoyancy of the plumes as related to the stack and tower heights. A further consideration is that in cases when the plumes would intermingle, they would not necessarily become intimately mixed. In the case of the

TABLE B-VIII-27
ENERGY PRODUCTION OF SOME NATURAL AND ARTIFICIAL PROCESSES AT VARIOUS SCALES (367)

Area (m^2)	Natural Production		Artificial Production	
	Event	Rate (W/m^2)	Type of Use	Rate (W/m^2)
5×10^{14}	Solar energy absorption by atmosphere	25	Man's ultimate energy production	0.8
10^{12}	Cyclone latent heat release (1 cm rain per day)	200	Northeast U.S. ultimate production (10^8 people, 20 kw each)	2.0
10^8	Thunderstorm latent heat release (1 cm rain per 30 min)	5000	Super energy center or city	1000
10^4	Tornado kinetic energy production	10^4	Dry cooling tower for 1000-Mw (e) powerplant	10^5

study of plant no. 4217, cited previously, measurements suggested that the plumes were not uniformly mixed and may have been merely co-mingled.

In any case, since hundreds of evaporative cooling towers have been operated over many years at coal-fired and oil-fired stations scattered across the United States without significant numbers of reports of adverse impacts due to "acid fog", the engineering and other design practices employed should be adequate to assure that this problem does not arise in subsequent applications of evaporative cooling towers.

In summary, potential adverse impacts due to fogging are not a national-scale problem. In the relatively few instances where it could be a problem, technology is available, at a moderate incremental cost, to control or eliminate fogging to the degree required by the related considerations.

Noise

Noise created by the operation of cooling towers, results from the large high-speed fans. The enormous quantities of air moving through restricted spaces, and large volumes of falling water contacting the tower fill and cold water basin also create noise. Mechanical draft towers will generate higher noise levels than natural draft towers. At sites where the incremental noise due to cooling towers might be a problem, it should be considered in the design of cooling tower installations. A three step procedure usually results in adequate coverage of this problem.

1. Establish a noise criteria that will be acceptable to the neighbors within hearing range of the proposed tower.

2. Estimate the tower noise levels, taking into account distance to neighbors, location of the installation, and orientation of the towers.

3. Compare the tower noise level with the acceptable noise level.

Only if the tower noise level exceeds the acceptable noise level need corrective action be taken.

All cooling towers and powered spray modules produce some noise. The noise from powered spray modules and natural draft cooling towers is primarily from the falling water. In the mechanical draft dry tower there is the fan noise and possible noise from high velocity flow of the water through the cooling surface.

Since the powered spray modules are normally located in a canal, the banks tend to direct the sound upward, and the bank surface can absorb part of the sound. Their use to date has not created serious noise problems.

The noise level from cooling towers is of the same order of magnitude as that in the rest of the station, and thus noise from both sources can be a problem in noise sensitive areas. Every effort should be made to place these structures away from potential sources of complaints. Sound levels decrease with the square of distance from the source. Large flat wall surfaces can direct sound into sensitive areas. At the same time, walls and buildings can act as a sound barrier. Fan speeds can be reduced at night when load is lowest and when ambient noise levels may also be lowest. Proper attention to noise problems in tower design, selection, and placement can avoid costly corrective measures.

It is possible to decrease fan noise about 10dB by reducing tip speed from 12,000fpm to 8,000fpm. This reduction, however, would be possible only if the fan being considered had the capability of handling 125% more pressure and 50% more flow without stalling. A rough estimate of fan cost versus decibel reduction is shown in Figure B-VIII-26. A 14-ft fan was used in the analysis but the costs would be proportional for any fan.[455]

If the above procedures are unable to reduce noise levels in the affected areas to acceptable levels, sound attenuation can be done by modification or addition to the tower. Discharge baffles, and acoustically lined plenums can be used. Barrier walls, or baffles can be erected. Adequate noise suppression is normally possible, but the cost can be high. Good practices can minimize the expense involved in noise suppression.

It is recognized that incremental costs would be incurred where mechanical draft cooling towers may require noise control. Little information is available on the cost of implementing noise control procedures on powerplant cooling towers principally because it has rarely been necessary to employ these measures, even though powerplants with cooling towers exist in areas of high population density. It is doubtful that there will be a significant need for this technology as a result of technology-based effluent limitations on heat, since many plants in areas of high population density would be exempted because of the lack of

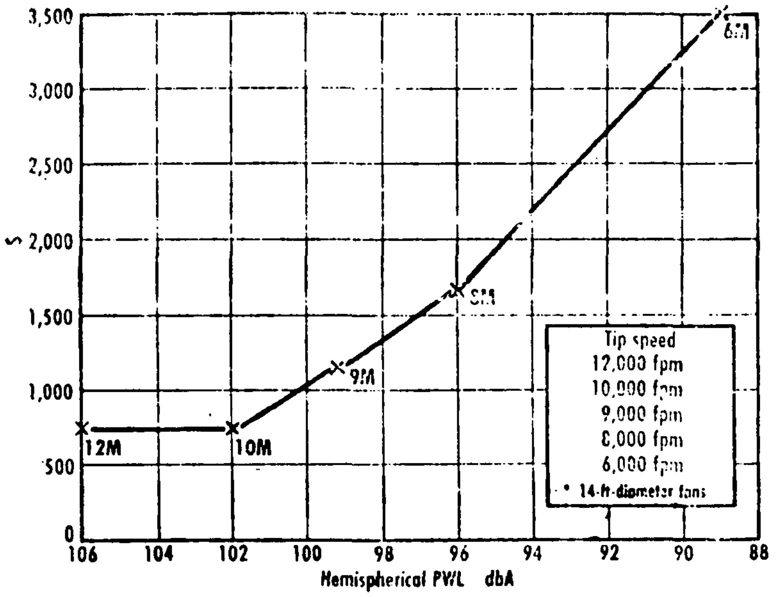


Figure B-VIII-26 Fan Cost Versus Noise Reduction
Reference 455

sufficient land for closed-cycle cooling systems, because of the salt drift exemption, or because of the exemptions based on age or size. Furthermore, alternative thermal control technologies may be employed that are generally quieter than mechanical draft cooling towers. In the only case cited by comments on the proposed effluent limitations, guidelines and standards, a plant in West Germany was reputed to have incurred twice the normal capital cost for cooling towers due to the installation of noise control equipment. This is a most unusual case indeed. The plant cited is in West Berlin, a politically land locked community isolated from outside power sources. Increased demand and a paucity of available sites required that a new plant be constructed in close proximity to residences in an area of high population density, hence, the need for noise abatement technology. Furthermore, it is significant that cooling towers were employed with noise suppressors in order to take advantage of the site while accomodating the need to reduce noise to locally required levels.

It is concluded that adverse impacts of noise is not a national-scale problem. Technology is available at a moderate cost to reduce the noise impact of cooling towers. In addition, alternate cooling system selection and proper locations of the towers can be used at highly sensitive sites. New plants have the further flexibility of site selection to help minimize this problem.

Height

The height of natural draft cooling towers, up to 183 meters (600 ft), results in a localized potential hazard to aircraft. Location of such a tower would generally not be permitted in the approaches to an airport. Other pertinent FAA restrictions and regulations would have to be complied with. Aircraft warning lights would have to be installed on the tower along with provision for servicing them. The height of alternative technologies would not present hazards to aircraft.

Consumptive Water Use

All evaporative heat rejection systems result in the consumptive use of water. The primary consumption occurs as evaporation and drift. Even the once-through system is responsible for consumptive use of water by evaporation during the transfer of heat from the river, lake or ocean to the atmosphere, the ultimate receiver.

Heat is transferred from the river or lake to the atmosphere by three major means, radiation, evaporation, and conduction, with that by conduction being small compared to the other two. The Edison Electric Institute report entitled, "Heat Exchange in the Environment" [84], gives a detailed analysis of these processes.

The closed systems, cooling towers and spray ponds, utilize the same mechanisms, although their respective contributions may be much different. Figure B-VIII-27, taken from a paper by Woodson, [318] gives a graphic representation of the percentages of heat transferred by each process. In a report prepared for EPA, [104] some representative consumptive use rates for a 1000 Mw unit are shown (see Table B-VIII-28). Consumptive use varies from 1.3 to 2.1 times that of a river or lake, depending on the type of closed system used.

Woodson, in his article, [318] gives a more detailed analysis, including costs to make up for penalties inherent in the use of closed systems as shown in Table B-VIII-29. Consumptive use, according to his figures, can be as much as 2.5 times that of a once-through system.

The amount of water consumed depends to some extent on the climatic conditions existing at the site. Some of these factors and their effect are shown in Figure B-VIII-28. [133] The use of cooling ponds results in the highest consumptive use, since the total consumptive loss is equal to the sum of the natural evaporation plus that due to heat rejection to the cooling pond. The increment of consumption due to natural evaporation is approximately the difference between the consumption of a cooling pond and that of a natural lake or river. The consumptive use of water in a natural lake or river is low, since the natural losses are not charged against the power station, and in addition, a significant part of the heat is transferred by radiation.

The dry-type cooling tower, as opposed to the wet-type cooling tower, has essentially no consumptive use of water. The only consumptive use would be losses from this closed system due to leaks.

In general, the replacement of a once-through cooling system with a closed system will result in somewhat higher water consumption from a broad environmental standpoint. This increase averages about 25% as shown in the referenced tables and graphs, and only represents the absolute difference in water consumed.

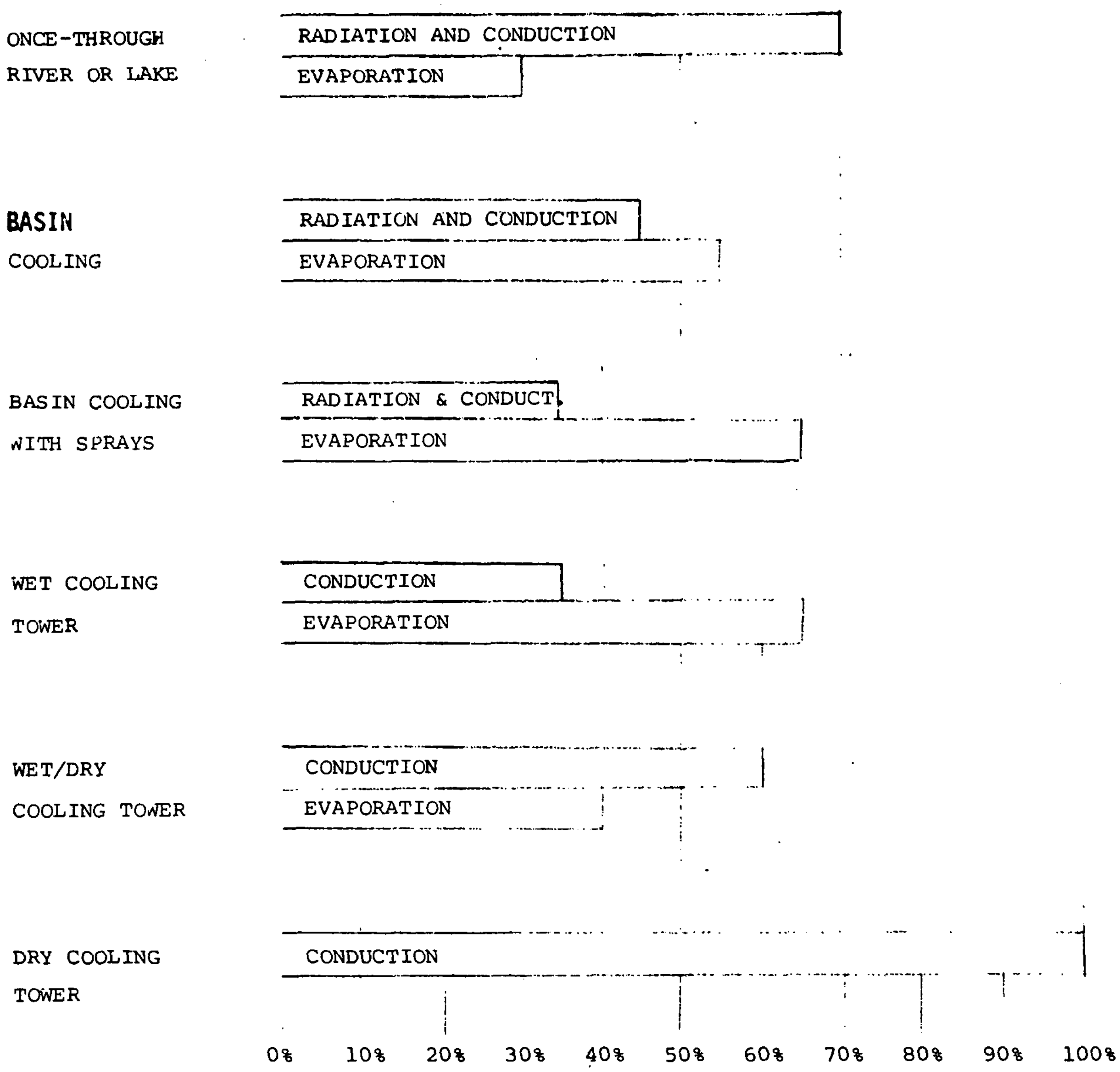


Figure B-VIII-27

HEAT TRANSFER MECHANISMS

WITH ALTERNATIVE COOLING SYSTEMS

(From Reference 318)

TABLE B-VIII- 28

EVAPORATION RATES FOR VARIOUS COOLING SYSTEMS (Reference 104)

Cooling System	Evaporation[1]	
	m^3/sec	cfs
Cooling Pond (2 acres/Mw)	.566	20.0
Cooling Pond (1 acre/ Mw)	.453	16.0
Mechanical Draft Tower	.368	13.0
Spray Pond	.360	12.7
Natural Draft Tower	.340	12.0
Natural Lake or River	.266	9.4

[1] For a 1000 Mwe fossil-fueled plant at 82 percent capacity factor average annual evaporation (assume constant meteorological conditions).

TABLE B-VIII- 29

COMPARATIVE UTILIZATION OF NATURAL RESOURCES

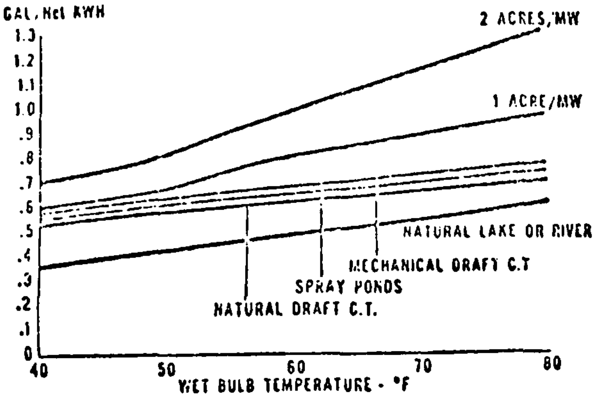
WITH ALTERNATIVE COOLING SYSTEMS
FOR
FOSSIL FUEL PLANT WITH

680 Mw NET PLANT OUTPUT
(70 per cent annual load factor)

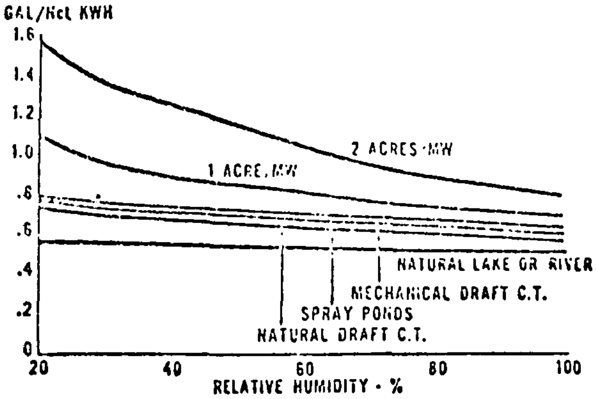
	Gross Generating Capacity kw	Net Plant Heat Rate Btu/kwh	Fuel Input Billions of Btu/yr	Coal Consumption 10,000 Btu/lb tons/yr	Water Consumption (Evaporation) Acre ft/yr	Land Area acres
	BASE REQUIREMENTS					
Once-through river or lake cooling system	715,580	9,489	39,567	1,978,343	2,800	
	ADDITIONS TO BASE REQUIREMENTS					
Alternative cooling systems						
Basin cooling facility	-	19	79	3,950	5,400	1,000
Basin cooling with auxiliary sprays	6,360	103	429	21,450	6,300	500
Mechanical draft wet tower	4,420	77	321	16,050	6,300	15
Mechanical draft wet/dry tower	5,070	86	358	17,900	2,800	15
Mechanical draft dry tower	17,770	1,123	4,682	234,100	*(2,800)	6
Natural draft wet tower	3,060	59	246	12,300	6,300	15

*Denotes Decreased Requirements

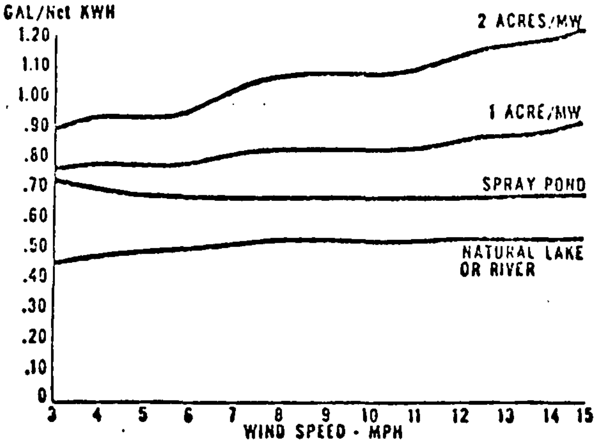
(From Reference 318)



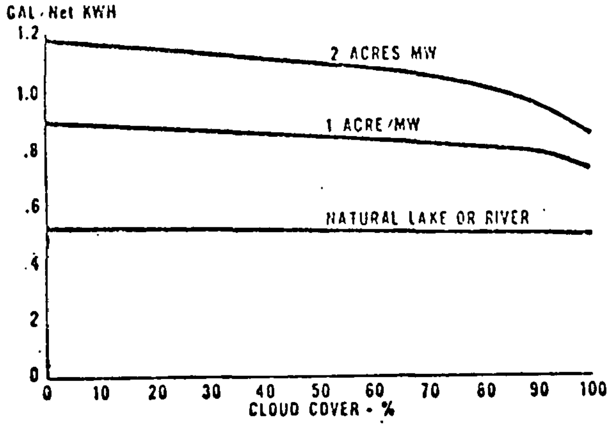
WATER CONSUMPTION VERSUS
WET BULB TEMPERATURE



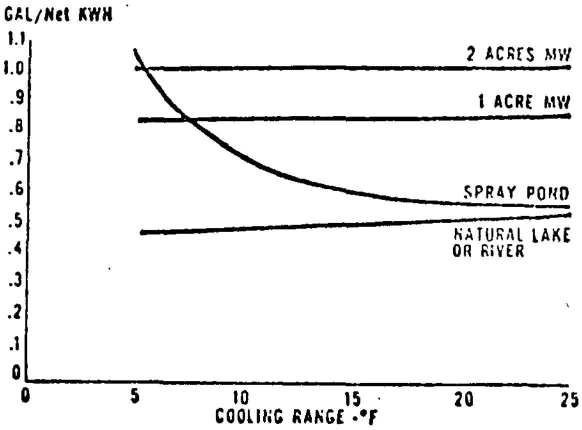
WATER CONSUMPTION VERSUS
RELATIVE HUMIDITY



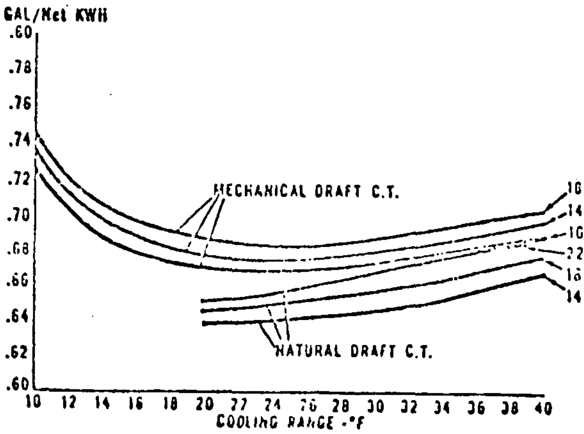
WATER CONSUMPTION VERSUS
WIND SPEED



WATER CONSUMPTION VERSUS
CLOUD COVER



WATER CONSUMPTION VERSUS TEMPERATURE RANGE FOR BODIES OF WATER



WATER CONSUMPTION VERSUS TEMPERATURE RANGE FOR COOLING TOWERS

(From Reference 133)
FIGURE B-VIII- 28
WATER CONSUMPTION VERSUS METEOROLOGY AND COOLING RANGE

Present powerplants have been sited, in many cases, where the lack of a reliable supply of quality cooling water has dictated the use of closed-cycle evaporative cooling. In other words, where water is in short supply, the more-highly water consuming evaporative cooling systems have been justified and legal rights to water consumption have been obtained where required. In many states water users and consumers must obtain legal rights to use or consume water. In some of these states all water use and consumption rights have already been allocated but not necessarily utilized. Rights can be bought and sold among users. Many powerplants have rights to more water than they currently use or consume. In some states powerplants have the power of eminent domain over water rights, and are thereby authorized to appropriate all or a part thereof to the necessary public use, reasonable compensation being made.

A comprehensive study, prepared by the Utility Water Act Group (Reference 441), of the water use implications of applying closed-cycle evaporative cooling to all steam-electric powerplants concluded that an increase of over 80 percent would result in the amount of fresh water consumed annually by these plants. When considering total freshwater consumption by all uses, complete closed-cycle cooling in the year 2000 is projected by the same study to increase the total water consumption nationally by 5.4 percent when compared to maintaining the existing mix of once-through and closed cooling systems. At the same time, the Water Resources Council projects possible shortages of water in the year 2000 in major portions of the U.S. from California to Texas. The study cited above projects for the year 1983 the following increases in freshwater consumption, over present freshwater consumption by powerplants for the arid regions from Texas to California:

	Base	Increases
Texas-Gulf	376.7MGD	125.7MGD
Rio Grande	36.8	0.0
Upper Colorado	43.1	0.0
Lower Colorado	65.6	0.0
Great Basin	5.3	0.2
California	47.0	197.4

The regions listed above encompass the geographical areas shown on Figure B-VIII-29.

The previously referenced study [441] further estimates that, in the case of California (which appears to be the worst

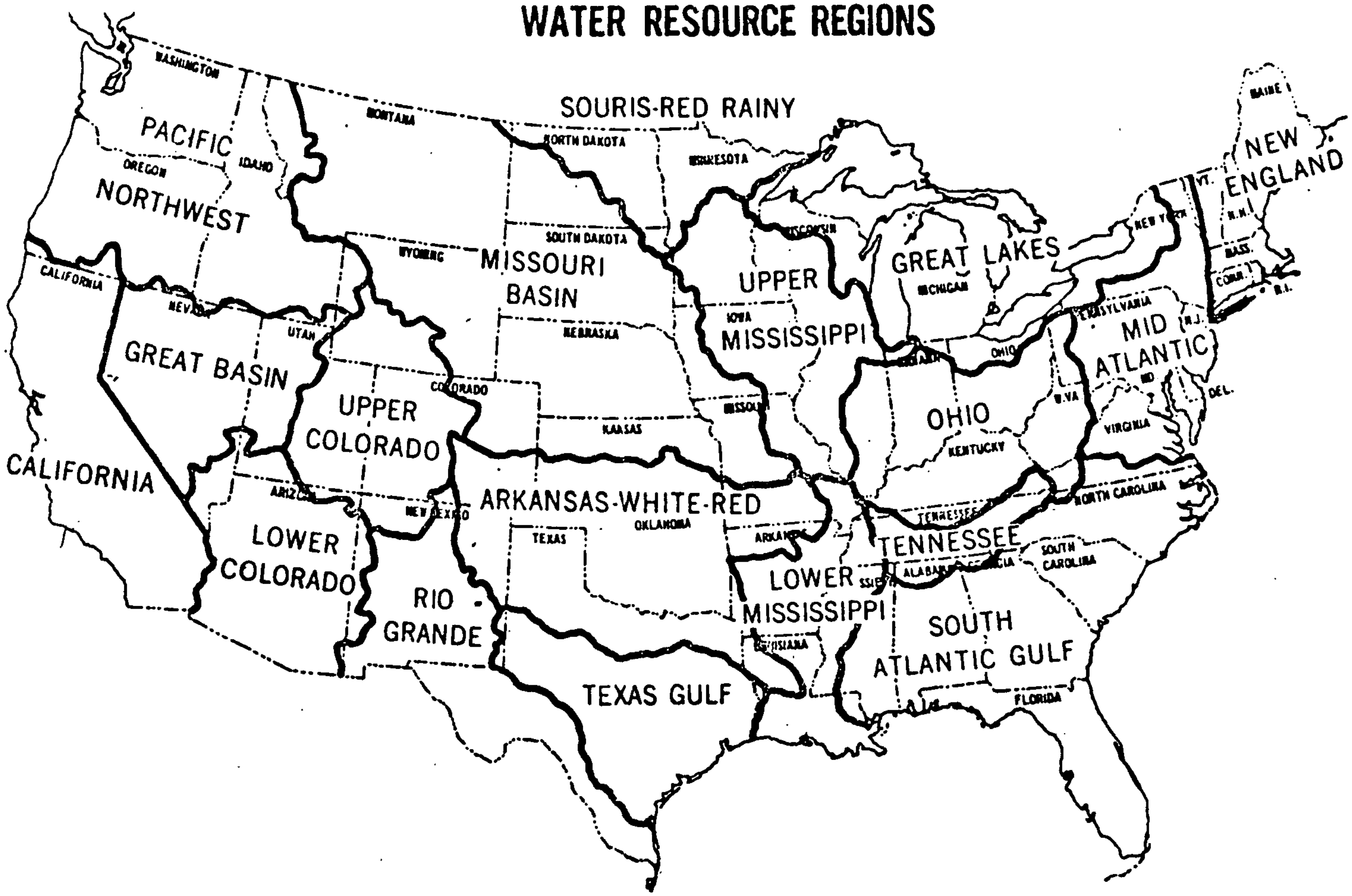


Figure B-VIII-29 Regions Upon Which Water Consumption Studies Have Been Based case for the 6 arid regions), in the year 2000 there will be, as a base, a deficit of 29.1 billion gallons per day of freshwater based on monthly flow available 95 percent of months (20-year drought). Corresponding to this, the freshwater consumption due to retrofitting of closed-cycle cooling to steam-electric powerplants would add 1.1 billion gallons per day to the base deficit during peak monthly power demands under summer conditions. For this worst case (of the 20-year condition) the increase in the water deficit that may be attributable to retrofitting is 3.8 percent of the base deficit.

The previously reference study prepared by the Utility Water Act Group indicates the consumptive use of freshwater due to retrofitting steam-electric powerplants in California for 1970, 1983 and 2000 as follows:

	Base	Increases
1970	19.8MGD	83.4MGD
1983	47.0	197.4
2000	198.9	835.9

The existing mix employed above for 1970 of 78.27 percent capacity using once-through saline cooling systems, 6.48 percent using once-through freshwater, and 15.25 percent using cooling towers, is based on FPC Form 67 data for 1970. Projections of increases for the years 1983 and 2000 were based on applying h same percentage to the base as was applied for the 1970 computations.

From the 1970 mix described above it can be seen that the consideration of salt water cooling towers which is an available alternative for plants using once-through saline systems would significantly diminish the projection of freshwater consumption indicated by Reference 441, which is based as the use of freshwater towers for plants using once-through saline systems. Reports submitted to the FPC by regional reliability councils in 1973 in response to Appendix A of Order 383-3 list projected steam-electric units 300 megawatts and larger for which construction has begun or is scheduled to begin within 2 years. These reports list 7,013 megawatts of generating capacity to be added in California over the years 1973-1980. Of this 5,802 megawatts are planned with once-through saline systems and cooling towers are planned for the remaining 2,211 megawatts. Considering all the plants listed in FPC Form 67 for 1970 and all the plants listed by the FPC for start-up in 1973-1980, incremental freshwater consumption will result only from retrofitting the 6.48% of the 1970 capacity which uses once-through freshwater cooling systems, or 1,280 megawatts out of the 26,792 megawatts covered by the two FPC sources. In contrast, the previously mentioned study by UWAG assumes retrofit freshwater cooling systems on 34,500 megawatts of generating capacity by 1983 for California.

Similar results would be obtained for the Texas-Gulf region which was assumed to have a capacity mix of 27.30 percent on once-through saline systems; 15.30 percent on once-through fresh systems; 36.00 percent on cooling ponds; and 21.40 percent on cooling towers. Subsequent to the publishing of the reference study, virtually all of the capacity identified above as being on once-through fresh systems has been determined to actually be on cooling lakes. Furthermore, the Electric Reliability Council of Texas, whose geographical area roughly coincides with the Texas-Gulf region, reported to the FPC in 1973 only 750 megawatts of capacity planning once-through cooling for units 300 megawatts and larger, out of 14,737 megawatts for which construction had begun or was scheduled to begin within 2 years. These capacity additions were planned to be placed into service over the period 1973-1982.

In Florida, which Reference 441 identified as a potential problem area for freshwater consumption due to retrofitting, 875 megawatts of capacity are reported by the Southeastern Electric Reliability Council to be planning once-through freshwater cooling out of a total of 8,919 megawatts to be added from 1973 to 1978.

Reported under FPC Docket R-362, April 1, 1974, Order No. 383-3, Appendix A-1 are cooling methods for projected generating unit additions, 300 megawatts and larger, for the period 1974-1983, for the entire U.S. Closed-cycle sytems total 181,702 megawatts and once-through systems (including many salt water systems) total 51,265 megawatts. Closed-cycle systems represent approximately 75 percent of the added generating capacity reported for this period. In summary, in all the regions where Reference 441 indicated that retrofitting would add to the year 2000 freshwater deficit, consideration of applying saltwater towers to once-through saline systems, identification of cooling lakes which had been accounted for as once-through freshwater systems, utilizing for projections cooling systems mixes based on regional reliability council reports rather than projecting the 1970 mix, and exclusion of the older, smaller generating units results in no indication of a significant contribution to freshwater deficits due to retrofitting.

Blowdown

In the closed cooling systems utilizing evaporative cooling, there is a buildup of dissolved and suspended solids, including water treatment chemicals, due to evaporation, which removes pure water, leaving the above constituents behind. Without some control over this buildup, scale and corrosion may occur, damaging the equipment and reducing its performance. To prevent excessive buildup, a small percentage of the water is continually removed from the circulating water system. This is normally called "tower blowdown" or "blowdown". The water that is added to replace this water, and the evaporative, drift and leakage losses, is known as makeup. The amount of blowdown is dependent on two factors. The primary factor is the avoidance of scale or other detrimental effects in the circulating water system. Of secondary importance is the quality of the blowdown water. The two types of scale normally encountered are $CaCO_3$ and $CaSO_4$. The $CaCO_3$ can be controlled by pH adjustment, with sulfuric acid normally being used to lower the pH. The $CaSO_4$ scale formation is avoided by maintaining the concentration of $CaSO_4$ below saturation. The $CaSO_4$ concentration is controlled by the amount of blowdown. Thus the amount of blowdown varies with the concentration of dissolved solids in the makeup water. The blowdown on fresh water towers amounts to on the order of 2% of the total flow through the tower. With some types of water, blowdown rates of less than 1% may be used. The blowdown rate is normally determined by the number of concentrations of dissolved salts allowed in the circulating water system. Concentrations of 10 or less are common, with concentrations as high as 20 being used.

Use of salt water makeup in cooling towers would decrease the number of permissible concentrations, increasing the blowdown rate. A blowdown rate equal to the evaporation rate would result in a blowdown twice as concentrated as the makeup. In addition to concentrated salts, this blowdown will have the chemicals used to treat the water to prevent corrosion and algae growth in the system. While chromates were previously used to a large extent, their use has decreased in recent years with the availability of other types of corrosion inhibitors.

Technology is currently available to control and treat pollutants in blowdown, to levels up to and including no discharge of pollutants. See Part A of this report for a description of the technology related to pollutants in blowdown.

Blowdown removed from the hot side of the circulating system is advantageous to the plant, as the heat in the blowdown does not have to be removed in a tower. However, it is a better environmental practice to discharge blowdown from the cool side. The percentage of heat involved is in the order of 2% of the total, and the thermal discharge could be correspondingly further reduced. The blowdown would normally be at a higher temperature than the receiving body, even if taken from the cool side, since the approach is to the wet bulb temperature, not the receiving water temperature.

Aesthetic Appearance

In addition to all the other factors described, the visual impact of the cooling system could be of concern to the neighboring residents and visitors. Cooling towers create two types of aesthetic impact. First, the large size of natural draft towers will dominate most settings in which they are placed. In this regard, natural draft towers can be as high as a 50 story building and cover an area at the base equivalent to several football fields. In all applications, they will dwarf the associated powerplant. Mechanical draft towers, on the other hand, are considerably smaller in height than the natural draft towers, although the aggregate base area of a multicelled unit may be larger than the base area of a natural draft unit for the same size plant. Therefore mechanical draft towers will not be as objectionable in this regard as will natural draft towers.

The second type of aesthetic impact is common to both types of towers. This impact is caused by the visible plume that can be generated by both types of evaporative systems where plume abatement is not employed. Cooling tower plumes will sometimes be larger than the stack emission from a fossil-fuel plant, especially in areas of high fogging potential. At some plants cooling tower plumes can be so insignificant that they escape notice by many viewers. Some cooling tower plumes, however, can be visible for several miles and be noticed even where the surrounding topography completely hides both the plant and the tower. As with fogging, plume abatement technology is available at moderate cost.

The question of whether a tower or its plume creates an adverse aesthetic impact is a subjective issue since the sensibilities of individual viewers varies widely. There are those who believe that all cooling towers create a visual nuisance. Others have expressed the opinion that the hyperbolic shape of cooling towers is visually pleasing.

The aesthetic impact of cooling towers is not necessarily a function of urban or rural location as some have suggested.

Discussions with utility representatives revealed as much opposition to cooling towers placed in rural settings such as along the California Coast and in scenic areas such as the Hudson River, as was voiced over towers placed in urban areas.

The impact of cooling tower aesthetics can effect the application of cooling towers at existing plants as well as at new sources. With existing plants locational factors will have been fairly well established and relatively little flexibility in the placement of the tower will be possible compared to new plants. The most critical plants will be those which are located in areas of mixed zoning. Residents of those areas which have accepted a powerplant in close proximity to their homes may object to the additional impact of a massive structure and a new, large, visible emission. In terms of aesthetic impact the mechanical draft tower is superior to the natural draft tower. The physical size of these units is much smaller than the natural draft tower and the mechanical draft tower can be fitted with plume suppressive equipment which is not yet available for natural draft towers. It is anticipated that this latter difference will be corrected in the near future. It may be that another type of evaporative cooling could be substituted for the tower in some instances. It is also noted that the fan-assist modification to the natural draft tower can substantially reduce its size.

For new plants where the location, site layout and architectural plan have not been finalized, considerably more can be done to abate adverse aesthetic impact than is possible at existing plants. In addition to the selection of a less imposing cooling system where possible, and the installation of plume abatement systems, the site location can be selected to reduce the cooling tower visual angles to a minimum. The site layout can be used to place natural barriers between the tower and the surrounding land uses. A pleasing grouping of building and common architectural treatment can be used to blend the facility into its surroundings.

Mechanical draft towers will more easily fit into the surrounding area. Plant no. 2612 is using the low hills surrounding the plant to almost completely screen the towers from view. Landscaping can hide or blend the towers into other types of terrain. Painting the towers can aid in making their appearance more pleasing.

Cooling lakes, if sufficiently large, can serve as recreation sites. With appropriate landscaping and structures, camping, boating, swimming, and fishing can be accommodated. One utility leases summer cabin sites along its cooling lake. Being low, these lakes normally blend well into the landscape. Landscaping of cuts and fill areas will normally be required.

Spray canals can be very pleasing to the eye if properly designed. Appropriate landscaping can hide the canal banks and power distribution systems. The sprays themselves can be attractive if arranged in a symmetrical pattern. They can be decorative, and be a definite asset to the plant's appearance.

In summary, aesthetics is not a national-scale problem. In cases where aesthetic impacts of towers and plumes could occur, alternative technologies are available and plume abatement technology is available at moderate incremental cost. New plants have the added flexibility of site selection to help minimize this problem.

Icing Control

Icing can result from the operation of cooling towers in cold weather. Ice formation is usually confined to the tower itself and adjacent structures within the plant boundaries. No cases of tower related ice formation at locations external to the plant are known to have been reported. Therefore, icing is an operational problem of the cooling system similar to the control of biological growths in the system rather than a nonwater quality environmental impact.

Control of cooling tower ice formation can be obtained by providing appropriate features in the tower design and employing certain procedures in tower operation during periods of cold weather. In the case of mechanical draft towers, ice formation in the louvers can be melted by periodically reversing the fans to drive air across the hot water and through the louvers. Louvers can also be di-iced by flooding them with hot water which is deliberatly spilled from the outer edge of the water distribution basin and allowed to cascade down over the louvers. In some instances louver icing can be controlled by concentrating the hot water load on the outmost segments of the fill during cold weather. This is accomplished by means of partitioned distribution basins and water distribution systems which allow for flexibility in the distribution of the water load over the fill area. For hyperbolics this is achieved by providing an annular channel at the outside edge of the fill and a distribution system which can divert a large fraction of the hot water into this channel.

During cold weather an annular segment of the fill of a cross flow hyperbolic or one or more cells of mechanical draft units may be taken off line. The resulting increased water loading also serves to reduce tower icing. In some of the new designs for hyperbolics, the fill is completely bypassed during periods of very cold weather and small plant loads.

Non-Water Quality Environmental Aspects of Spray Cooling Systems

The text of this subsection is exerpted from Reference 405.

Ceramic Cooling Tower Co. presents a pseudo-technical comparison, using known psychrometric principles, to display the relative magnitude of fog intensity and frequency probability between conventional cooling towers and powered spray modules. Superiority of the spray is rationalized qualitatively by comparing such apparent differences as: (a) Sprays provide substantially greater area and air volume for head dissipation of identical duty; (b) Air discharged from the spray is not as near saturation as that from a tower; (c) Temperature of air in tower exhaust is close to water temperature but downwind of spray the air temperature is significantly less.

Extensive winter tests of one Cherne Thermal Rotor module were sponsored by 31 electric companies. On approximately 15 mornings when natural fog was present, observable amounts of fog continued to be produced by the Rotor for 10-15 minutes after natural fog lifted. With winds less than 15 miles per hour (4.3 kn) and air temperature less than 10°F (-12°C) hoarfrost (rime ice) was observed to a maximum of about 100 ft (30 m). Ice accumulated to several inches on a embankment about 20 ft (6 m) from the edge of the spray pattern.

Commonwealth Edison of Chicago (Illinois) contracted detailed micrometeorological studies of a cooling lake and test sprays at a plant in Illinois. Although the effects of the sprays are difficult to isolate from the total, observations made near the sprays may be useful. The highest frequencies of steam fog occured in the early morning. The overwhelming majority of steam fog observed remained aloft. Fog travelled at or near ground level 150 ft (46 m) or more, for short periods of time, on 60 days out of 456 from January, 1972, through March, 1973. Only 10 per cent of the extrusions were more than 175 ft (53 m). Six times rime ice deposited at a distance of 150 ft (46 m) or more; a maximum distance occurred twice at 425 ft (130 m). On two occasions during winter months a very light trace of snow was observed to fall out of the steam fog.

Little objection is raised concerning environmental effects of drift from freshwater systems, but some concern is expressed for salt water systems because of potential damages to surrounding area from the fallout of salt. Data presented here were obtained by different methods and may not be comparable.

Ceramic reports that the composite of substantial testing at various sites of generally full scale systems, under numersous atmospheric conditions, indicates that measureable drift, during any meaningful time period, does not exceed a distance of 600 ft (183 m) from the sprays. These tests are based on dissolved solids fallout into collection pans of accurately determined area of controlled time periods. Average curves are presented for 1, 2, 4, and 6 units arranged axially perpendicular to the predominant wind direction. These curves show, for example, that one module with 10 MPH (8.6 kn) wind will deposit 0.002 gal/day/sq ft (0.082 l/day/sq m 100 ft (30m)) from the spray. Deposition with multiple modules is not linear; six modules will deposit about 0.004 gal/day/sq ft). "Drift Multipliers" for approximating deposition at different wind speeds are presented; these range from about 0.1 for 3 MPH (2.6 kn) to 2.2 for 15 MPH (13 kn).

Cherne presents a graph of maximum deposition rate as function of distance for winds up to 14 MPH (12 kn). At 100 ft (30 m) from the Rotor the maximum rate is 0.05 lbs/hr/sq ft (5.86 l/day/sq m). At about 470 ft (143 m) the rate is 0.0004 lbs/hr/sq ft (0.047 l/day/sq m), which is the resolution limit of the test. The tests involved collecting samples of droplet fallout over short time periods in glass petri dishes and immediately weighing on precision laboratory balance. Surprisingly, little correlation with wind speeds up to 14 MPH (12 kn) was noted.

Richards approximates the drift emission characteristics, or the amount carried away, in contrast to deposition. The analysis is based on drop size distribution and particle transport theory. The investigators point out that there are no data available on either drop sizes or distribution to be expected from breakup of massive sprays. However, estimates of drop size distribution were made by analyzing close-up photographs of sprays. These estimates agreed well with those predicted by Fan Jet theory. Turbulent effects in vertical directions were ignored but compensated by other conservative assumptions in the calculations.

Drift emission characteristics are presented graphically in units of amount of suspended spray at various distances as a function of different wind speeds. It is difficult to summarize this complex graph, but typical numbers for a single module are as follows: a 5 MPH (4.3 kn) wind carries 10 lbs/hr (4.5 kg/hr) of spray a distance of 100 ft (30 m); a 20 MPH (17 kn) wind carries the same amount to 500 ft (152 m).

Measurements made for Ceramic during operation of full scale PSM systems in various terrain situations indicates that the sound pressure level from operation of the full system reaches background level at 200-250 ft (61-76 m) when wind was calm to 5 MPH (4.3 kn). The octave band level is rather flat with a maximum around 425 Hertz. Tests with 14 Richards modules indicate attenuation to background at about 2,000 ft (610 m). No wind data are presented. Octave band level near the sprays is rather flat also, with the maximum around 500 Hertz. Higher frequencies decrease with increasing distance.

Spray cooling requires less than 5 percent of the land area of a cooling pond for the same cooling duty. No chemical additives to the circulating water are required by spray equipment. Consequently, possible air or water pollution by such additives is not a problem. Under summer operating conditions 80-90 percent of cooling is accomplished by evaporation; less for annual average conditions.

Hoffman gives an excellent summary of spray systems. In it he concludes: "It is the opinion of this author that floating spray modules commercially available are an attractive alternative when designing powerplant condenser cooling systems. The thermal performance of such systems is predictable and measurable. The adverse environmental effects caused by spray systems can be largely mitigated by careful design procedures and by taking advantage of the operating flexibility that is inherent in spray canal systems."

The data presented to date substantiate Hoffman's conclusion. The major deficiency at this time is the prefection and verification of models to predict drift transport.

The U.S. Environmental Protection agency has begun studies in co-operation with Florida Power and Light Company on salt water cooling at the Turkey Point Station near Miami (Florida). These studies will include ambient (natural) air chloride concentration and deposition, salt water drift emissions from mechanical draft towers and spray modules, fallout characteristics, and terrestrial effects on native and cultured vegetation.

Ashbrook Corporation has entered into a co-operative program in New York State University. The purpose is to determine quantitatively ice formation and drift deposition rates as functions of distance from the spray source.

Detroit Edison and its consultants are continuing to study environmental effects of cooling system alternatives.

Non-Water Quality Environmental Aspects of Surface Cooling

The text of this subsection is exerpted from Reference 413.

In cooling ponds, evaporation is one of the main mechanism in the dissipation of waste heat load and this takes place at the water surface. If subsequent condensation occurs, it will take place not far above the water surface. Induced fogs (and freezing fogs) formed in this way may drift downwind and reduce visibility. Evaporation of heated effluent from once-through cooling systems would produce the same effects.

There is a lack of information on the frequency, intensity, and inland penetration of cooling pond-induced fogs. Reported observations at existing cooling ponds indicate that the fog, categorized as thin and wispy, will not penetrate inland more than 30.5 to 152.5 m (100 to 500 feet)[414]; although under severe conditions fog may extend from 3 to 18 km (1.86 to 11.2 miles). Ice crystals suspended in the atmosphere have also been observed. The particular danger associated with freezing fog is that the supercooled droplets, coming into contact with solid surfaces, freeze immediately and form a thick and smooth layer of ice. This could be a hazard on road surfaces.

Any increase in local fog or clouds created by either cooling ponds or towers will lead to a decrease in the amount of solar radiation, including ultraviolet radiation, received at the surface[415].

Recent studies[416] on the severity of fogging caused by warm water lagoons used for power station cooling show that steaming increases as the humidity increases, and the air temperature decreases.

Comparison of Control Technologies

The available control and treatment technologies for effluent heat are compared in Table B-VIII-30 based on incremental costs (production, capital, fuel, and capacity), effluent reduction benefits, and nonwater quality environmental impacts.

Costs Versus Effluent Reduction Benefits

A study was made [456] of the incremental costs of controlling at various levels the quantity of heat discharged into a river (in Belgium) by a 1000Mw nuclear unit, using a once-through system as a base. See Figure B-VIII-30. Various methods were assumed for achieving successive incremental reductions in effluent heat, as shown in Table B-VIII-31. The incremental costs of each successive effluent heat reduction are also given in the table compared to the percent effluent heat reduction that would be attained. The table shows that the incremental costs are lowest in relation to the effluent reduction benefits for the incremental heat removal with the closed circuit employing simple treatment of make-up water. To achieve a 95.8 percent effluent heat reduction the incremental costs would be 86.2 percent of the incremental costs of 100 percent heat reduction.

The incremental costs (production, capital, fuel, and capacity), and costs versus effluent reduction benefits of the application of mechanical draft evaporative cooling towers to nonnew nuclear units and fossil-fueled units (base-load, cyclic, and peaking) with various years of remaining service life is shown in Table B-VIII-32. A similar costs breakdown for new units is given in Table B-VIII-33. Both tables indicate the assumptions used in the cost analyses.

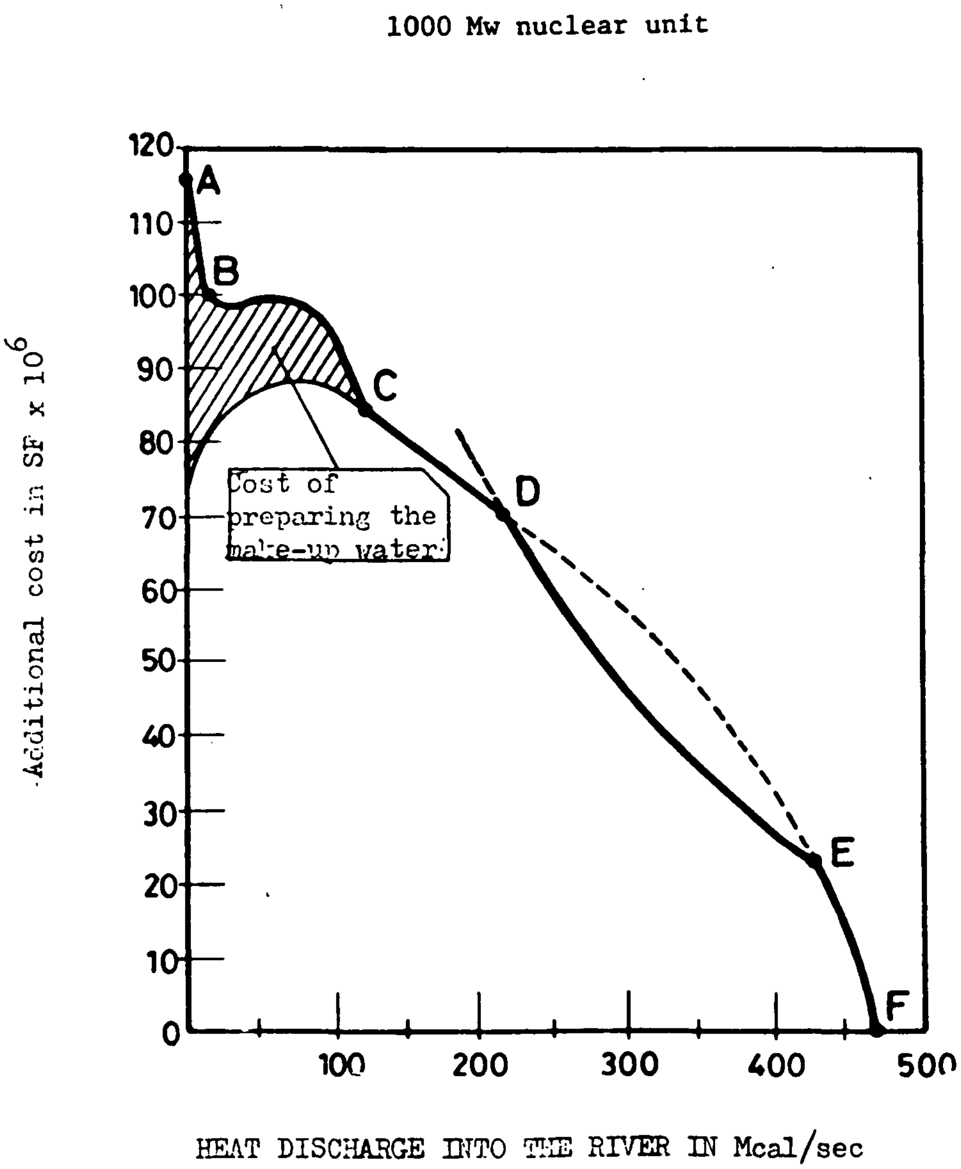
In general for nonnew sources, the total costs of the application of thermal control technology in relation to the effluent reduction benefits to be achieved from such application are the most favorable for the newest, most highly utilized generating units, and, progressively, the least favorable for the oldest, least utilized generating units. For new sources the costs versus effluent reduction benefits are even more favorable due to the absence of "backfitting" costs of any kind, which would be a major cost for nonnew sources. In the intermediate case of a nonnew

TABLE B-VIII-30

CONTROL AND TREATMENT TECHNOLOGIES FOR HEAT
COSTS, EFFLUENT REDUCTION BENEFITS, AND NON-WATER QUALITY ENVIRONMENTAL IMPACTS

TECHNOLOGY (Approx. no. of units employing technology)	INCREMENTAL COST FOR MAX. EFFL. RED. % Base				EFFL. RED. BENEFITS % Base	NONWATER ENVIRONMENTAL IMPACTS % Base					
	Production	Capital	Fuel	Capacity		Fog	Drift	Noise	Aesthetics	Land	Water Consumption
Once-Through(2500)	0	0	0	0	0	0	0	0	0	0	0
Process Change(0)	100	100	15gain	15gain	15max	0	0	0	0	0	0
Surface Cooling(100)											
Unaugmented	10-20	9-14	1-2	3-4	0-100	0	0	0	0	2000	100
Augmented	10-20	9-14	1-2	3-4	0-100	*	*	0	*	1000	200
Evaporative(Wet) Tower											
Mechanical Draft(250)	10-20	9-14	1-2	3-4	0-100	*	*	*	*	30	200
Natural Draft(60)	10-20	9-14	1-2	3-4	0-100	0	0	0	*	30	200
Dry Tower(1)	20-40	11-16	4-5	7-10	0-100	0	0	*	0	30	30gain
Wet/Dry Tower(1)	14-28	10-15	2-3	4-5	0-100	0	*	*	0	30	35
Alternative Processes											
Hydroelectric(100's)	0	0	100gain	0	0-100	0	0	0	0	2000	80gain
Internal Combustion(100's)	100	100	0	0	0-100	0	0	*	0	0	100gain
Combined Cycle(approx.50)	app 50	app 50	app 50gain	0	app 50	0	0	*	0	0	50gain

* Note: Some highly site-specific incremental impacts, but not generally anticipated to be limiting.



AB - Closed circuit with decarbonation of the make-up water

BC - idem - simplified treatment

CD - EF - Mixed circuit

DE - Cooling on discharge

F - Open circuit

Figure B-VIII-30 Additional Cost Versus Heat Discharged[456]

Table B-VIII-31

COST VERSUS EFFLUENT REDUCTION BENEFITS, 0-100 % REMOVAL OF HEAT

Basis: Figure B-VIII-30 (Reference 456)

Cooling Method	Effluent Heat Reduction, % of base heat discharged		Incremental Cost, % of total incremental cost for 100% heat reduction		Incremental Cost,% / Incremental Heat Reduction,%	
	Incremental	Accumulated	Incremental	Accumulated	Incremental	Accumulated
Base: Open circuit (once-through)	0	0	0	0	-	-
Cooling on discharge (once-through with "helper")	8.5	8.5	19.8	19.8	2.33	2.33
Mixed circuit (partial recycle of water cooled by the tower)	63.9	72.4	53.5	73.3	0.84	1.01
Closed circuit with simple treatment of make-up water	23.4	95.8	12.9	86.2	0.55	0.90
Closed circuit with decarbonation of make-up water	4.2	100	13.8	100	3.29	1.00

TABLE B-VIII-32

INCREMENTAL COST OF APPLICATION OF MECHANICAL DRAFT EVAPORATIVE COOLING TOWERS TO NONNEW UNITS (BASIS 1970 DOLLARS)

TYPE UNIT	REMAINING LIFE Years	INCREMENTAL PRODUCTION COSTS % of Base Cost	INCREMENTAL PRODUCTION COSTS Cost/Benefit $\$/[MWH]_T$ x10	INCREMENTAL CAPITAL COSTS % of Base Cost	INCREMENTAL CAPITAL COSTS Cost/Benefit $\$/[MWH]_T$ x10	ADDITIONAL FUEL CONSUMPTION % of Base Fuel Consumption	ADDITIONAL FUEL CONSUMPTION Cost/Benefit $[MWH]_F/[MWH]_T$ x100	GENERATION CAPACITY REDUCTION % of Base Generating Capac.	GENERATION CAPACITY REDUCTION Cost/Benefit $MW/[MWH]_T$ $x10^7$
I. Nuclear (All base-load)	30-36	13	4	12	1	2	3	3	1
	24-30	14	5	12	1	2	3	3	1
	18-24	15	5	12	2	2	3	3	1
	12-18	16	6	12	2	2	3	3	2
	6-12	19	7	12	5	2	3	3	3
	0-6	30	11	12	10	2	3	3	9
Average excl. 0-6		15	5	12	2	2	3	3	1.6
II. Fossil-Fuel									
A. Base-Load	30-36	11	4	12	1	2	3	4	1
	24-30	12	4	12	1	2	3	4	1
	18-24	13	4	12	1	2	3	4	1
	12-18	14	5	12	2	2	3	4	2
	6-12	16	5	12	3	2	3	4	3
	0-6	22	7	12	8	2	3	4	9
Average excl. 0-6		13	4	12	1.6	2	3	4	1.6
B. Cyclic	30-36	14	5	14	2	2	3	4	1
	24-30	15	5	14	2	2	3	4	1
	18-24	16	6	14	2	2	3	4	2
	12-18	18	6	14	3	2	3	4	3
	6-12	20	8	14	5	2	3	4	5
	0-6	30	10	14	15	2	3	4	14
Average excl. 0-6		17	6	14	3	2	3	4	4
C. Peaking	30-36	40	20	16	7	2	3	4	6
	24-30	40	20	16	8	2	3	4	7
	18-24	45	20	16	10	2	3	4	9
	12-18	50	30	16	13	2	3	4	13
	6-12	60	30	16	21	2	3	4	21
	0-6	100	60	16	61	2	3	4	64
Average excl. 0-6		47	24	16	10	2	3	4	11

Assumptions: TYPE UNIT	Base Prod. Cost mills/kwh	Base Cap. Cost $/kw	Annual Boiler Capacity Factor	Heat Rate Btu/kwh	Heat Loss Btu/kwh	Heat Converted Btu/kwh	Heat to Cooling Water Btu/kwh	Cost Replacement Capac. $/kw
I. Nuclear	6.50	150	0.70	10,500	200	3,500	6,800	90
II. Fossil-Fuel								
A. Base-Load	6.34	120	0.77	10,500	500	3,500	6,500	90
B. Cyclic	8.35	120	0.44	11,500	500	3,500	7,500	90
C. Peaking	12.5	120	0.09	12,500	500	3,500	8,500	90

Subscripts: F indicates electrical equivalence of fuel consumed, and T indicates electrical equivalence of heat rejected to cooling water. Both are calculated at 0.293×10^{-6} [MWH]/Btu.

TABLE B-VIII-33
INCREMENTAL COST OF APPLICATION OF MECHANICAL DRAFT EVAPORATIVE COOLING TOWERS TO NEW UNITS (BASIS 1970 DOLLARS)

TYPE UNIT	INCREMENTAL PRODUCTION COSTS		INCREMENTAL CAPITAL COSTS		ADDITIONAL FUEL CONSUMPTION		GENERATION CAPACITY REDUCTION	
	% of Base Cost	Cost/Benefit $/[MWH]$_T$ x10	% of Base Cost	Cost/Benefit $/[MWH]$_T$ x10	% of Base Fuel Consumption	Cost/Benefit [MWH]$_F$/[MWH]$_T$ x100	% of Base Generating Capac.	Cost/Benefit MW/[MWH]$_T$ x10
I. Nuclear (All base-load)	10	3	9	1	1	2	3	1
II. Fossil-Fuel								
A. Base-Load	10	3	9	2	1	2	4	1
B. Cyclic	11	4	10	4	1	2	4	1
C. Peaking	28	13	11	18	1	2	4	4

Assumptions: TYPE UNIT	Useful Life Years	Base Prod. Cost mills/kwh	Base Cap. Cost $/kw	Annual Boiler Capacity Factor	Heat Rate Btu/kwh	Heat Loss Btu/kwh	Heat Converted Btu/kwh	Heat to Cooling Water Btu/kwh	Cost Replacement Capac. $/kw
I. Nuclear	40	6.50	150	0.70	10,500	200	3,500	6,800	150
II. Fossil-Fuel									
A. Base-Load	36	6.34	120	0.77	10,500	500	3,500	6,500	120
B. Cyclic	36	8.35	120	0.44	11,500	500	3,500	7,500	120
C. Peaking	36	12.5	120	0.09	12,500	500	3,500	8,500	120

Subscripts: F indicates electrical equivalence of fuel consumed, and T indicates electrical equivalence of heat rejected to cooling water. Both are calculated at 0.293×10^{-6} [MWH]/Btu.

source for which construction has not been completed and some backfitting cost attributable to construction aspects would not occur, the costs versus effluent reduction benefits are likewise at a level of favorability above the typical operational nonnew source and below the new source.

For otherwise similar units, the cost versus effluent reduction benefits are the most favorable for those that will be the most highly utilized, or base-load units. The costs versus effluent reduction benefits are the least favorable for the units that will be utilized the least, or peaking units. Cyclic units rank intermediate between base-load and peaking units. In any case, the costs versus effluent reduction benefits for units that are to be retired from service within 6 years are very high when compared to the newer units in that class of utilization (base-load, cyclic, peaking) which have a greater remaining service life.

Considerations of Section 316(a)

Section 316(a) of the Act authorizes the Administrator to impose (on a case-by-case basis) less stringent effluent limitations when a discharger can demonstrate that the effluent limitation proposed for the thermal component of the discharge from his source is more stringent than necessary to assure the protection and propagation of a balanced, indigenous population of shellfish, fish and wildlife in and on the waterbody. The procedures for implementing Section 316(a) may extend over an estimated time span of approximately from two months to twenty months depending, from case-to-case, in the extent to which additional studies are required to establish effluent limitations based on environmental need. Correspondingly, the timing for cases leading to significant thermal controls could extend in some cases to the end of 1980. See Table B-VIII-34. The Act does not authorize extentions of the implementation dates for best practicable control technology currently available at individual sources to dates after July 1, 1977, or for best available technology economically achievable to dates after July 1, 1983, even in consideration of Section 316(a).

Table B-VIII-34

TIMING FOR CASES LEADING TO SIGNIFICANT THERMAL CONTROLS

ACCOMPLISHMENT	EARLIEST	LIKELIEST	LATEST
Propose effluent limitations guidelines	Mar 1974	Mar 1974	Mar 1974
Propose Section 316(a) procedures	Mar 1974	Mar 1974	Mar 1974
Begin Section 316(a) procedures	Mar 1974	Mar 1974	Mar 1974
Promulgate effluent limitations guidelines	Oct 1974	Oct 1974	Oct 1974
Promulgate Section 316(a) procedures	Oct 1974	Oct 1974	Oct 1974
Establish effluent limitation based on Section 316(a) procedures	Oct 1974	Sep 1975	Feb 1976
Discharger selects control means	Nov 1974	Nov 1975	May 1977
Discharger awards construction contract	Feb 1975	Feb 1976	Aug 1977
Discharger meets effluent limitation with...			
● Mechanical draft cooling tower	Aug 1976	Nov 1977	Aug 1979
● Natural draft cooling tower	Jan 1978	Apr 1979	Dec 1980
● Other means*	Feb 1977	Feb 1978	Aug 1979

* Note: Assumes two years after award of construction contract in each case.

PART B

THERMAL DISCHARGES

SECTIONS IX, X, XI

BEST PRACTICABLE CONTROL TECHNOLOGY CURRENTLY AVAILABLE, GUIDELINES AND LIMITATIONS

BEST AVAILABLE TECHNOLOGY ECONOMICALLY ACHIEVABLE, GUIDELINES AND LIMITATIONS

NEW SOURCE PERFORMANCE STANDARDS AND PRETREATMENT STANDARDS

Limitations

Based on consideration of the factors set forth in the Act, the effluent limitations for thermal discharges corresponding to the best practicable control technology currently available, best available technology economically achievable, and new source performance standards are described below. No limitations on heat are prescribed for pretreatment since this pollutant parameter is not incompatible with municipal wastewater treatment processes.

The technological basis for limitations of no discharge of heat is closed-cycle evaporative cooling, such as mechanical draft and natural draft cooling towers, spray cooling systems and cooling ponds and cooling lakes. For all new sources the effluent limitation is no discharge of heat from the main condenser except:

1. Heat may be discharged in blowdown from recirculated cooling water systems provided the temperature at which the blowdown is discharged does not exceed at any time the lowest temperature of recirculated cooling water prior to the addition of the make-up water.

2. Heat may be discharged in blowdown from cooling ponds provided the temperature at which the blowdown is discharged does not exceed at any time the lowest temperature of recirculated cooling water prior to the addition of the make-up water.

For all other sources the effluent limitation is no discharge of heat from the main condensers except:

1. Heat may be discharged in blowdown from recirculated cooling water systems provided the temperature

at which the blowdown is discharged does not exceed at any time the lowest temperature of recirculating cooling water prior to the addition of the make-up water.

2. Heat may be discharged in blowdown from recirculated cooling water systems which have been designed to discharge blowdown water at a temperature above the lowest temperature of recirculated cooling water prior to the addition of make-up water providing such recirculating cooling systems have been placed in operation or are under construction prior to the effective date of this regulation.

3. Heat may be discharged where the owner or operator of a unit otherwise subject to this limitation can demonstrate that a cooling pond or cooling lake is used or is under construction as of the effective date of this regulation to cool recirculated cooling water before it is recirculated to the main condensers.

4. Heat may be discharged where the owner or operator of a unit otherwise subject to this limitation can demonstrate that sufficient land for the construction and operation of mechanical draft evaporative cooling towers is not available (after consideration of alternate land use assignments) on the premises or on adjoining property under the ownership or control of the owner or operator as of March 4, 1974 and that no alternate recirculating cooling system is practicable.

5. Heat may be discharged where the owner or operator of a unit otherwise subject to this limitation can demonstrate that the total dissolved solids concentration in blowdown exceeds 30,000 mg/l and land not owned or controlled by the owner or operator as of March 4, 1974 is located within 150 meters (500 feet) in the prevailing downwind direction of every practicable location for mechanical draft cooling towers and that no alternate recirculating cooling system is practicable.

6. Heat may be discharged where the owner or operator of a unit otherwise subject to this limitation can demonstrate to the regional administrator or State, if the State has NPDES permit issuing authority, that the plume which must necessarily emit from a cooling tower would cause a substantial hazard to commercial aviation and that no alternate recirculated cooling water system is practicable. In making such demonstration to the regional administrator or State the owner or operator of such unit must include a finding by the Federal Aviation Administration that the

visible plume emitted from a well-operated cooling tower would in fact cause a substantial hazard to commercial aviation in the vicinity of a major commercial airport.

7. Heat may be discharged from a unit of less than 25 megawatts generating capacity or any unit which is part of an electric utilities system with a total net generating capacity of less than 150 megawatts.

8. Heat may be discharged from a unit of less than 500 megawatts generating capacity which was first placed in service on or before January 1, 1974.

9. Heat may be discharge from a unit with a generating capacity of 500 megawatts or greater which was first placed in service on or before January 1, 1970.

Compliance dates for effluent limitations on heat for all but new sources is July 1, 1981 except as follows:

In the event that a regional reliability council, or when no functioning regional reliability council exists, a major utility or consortium of utilities, can demonstrate to the regional administrator or State, if the State has NPDES permit issuing authority, that the system reliability would be seriously impacted by complying with the effective date set forth above, the regional administrator may accept an alternative proposed schedule of compliance on the part of all the utilities concerned providing, however, that such schedule of compliance will require that units representing not less than 50% of the affected generating capacity shall meet the compliance date, that units representing not less than an additional 30% of the generating capacity shall comply not later than July 1, 1982 and the balance of units shall comply not later than July 1, 1983.

Factors

The Agency has reviewed the bases on which the thermal limitations were determined to be applicable to units with differing operating characteristics, climatic conditions, and site related features. Additional distinctions among units have been made as a result of this review. A very large number of factors were considered including those suggested, as potential criteria for exemption from thermal control, by commentors who reviewed the proposed effluent limitations guidelines and standards for steam-electric powerplants. To address them in an orderly manner requires that those which serve explicitly or implicitly as a basis for distinctions in the applicability of the requirement for closed-cycle evaporative cooling be discussed first.

(A) Age

The cost, expressed in relation to power generated, is inversely related to the number of years of service life remaining for a particular generating unit. That is, the shorter the remaining useful life over which the cost of the cooling system may be amortized, the greater will be the percentage of the capital cost charged against each unit of power generated. Moreover, the shorter the remaining useful life, the less heat will be rejected to the environment particularly since many older units traditionally operate only during periods of higher demand. Accordingly, the capital cost expressed as a function of units of heat removed will be greater for older plants.

In addition, however, the absolute cost of retrofitting existing once-through units with closed-cycle cooling is substantially greater than is the cost of installing cooling equipment at new units. An exemption cast in terms of remaining service life accomodates this disparity but does so only in the most extreme cases.

In order to avoid the additional costs of conversion of older units to closed-cycle cooling to the maximum degree consistent with the protection of the environment, the Agency has expanded the exemption based on age. No unit placed into operation before January 1, 1970 will be required to meet the limitations on the discharge of heat. Of the units placed into operation between January 1, 1970 and January 1, 1974 only the largest baseload units (i.e., those of 500 megawatt capacity or greater) will be subject to control.

The Agency was urged to exempt all existing units from thermal control, requiring closed-cycle cooling only of new units. Because of the long lead times required for design and construction of powerplants, particularly nuclear units, and the definition of the terms "new source" and "construction" in section 306 of the Act, this would have resulted in confining applicability of the regulation to units which will not commence operation until the end of the decade. Moreover, the units placed into service since the start of this year and those scheduled for completion during the next several years are typically large units. Adopting a "new source" cutoff would exempt units exceeding 1000 megawatts, some of which will still be operating, and discharging heat, past the year 2000. In view of the extended periods of time during which these plants would be operating and discharging heat, the Agency concluded that they should remain subject to thermal control.

(B) Size

There are a very large number of small units (defined by the Federal Power Commission as units in plants of 25 megawatts or less and in systems of 150 megawatts total capacity or less). Yet these systems and units represent only a very small percentage of the total installed generating capacity in the United States. Moreover, the potential for higher costs due to site specific pecularities at any given unit could be expected to be balanced by more favorably located units in a larger utility system. In very small systems, this expectation of counterbalancing unit costs is less justifiable and the costs of meeting the thermal limits may not be economically achievable. On this basis the Agency proposed an exemption from the thermal limitations defining best practicable control technology currently available for existing small units and systems.

The exemption has been extended to apply to the thermal limits required by the best available technology economically achievable, in order to preclude the necessity of retrofitting such small units.

The promulgated regulation makes a second distinction based on rated capacity, or size. The effect of the revision to the regulation described above is tc exempt from controls on thermal discharge all units operating before January 1, 1974, except for units of 500 megawatts or greater. In the case of such very large units, the regulation imposes control on those placed into operation on or after January 1, 1970. An analysis of a survey of 60 plants submitted by an industry representative during the comment period indicates that the capital cost of retrofitting units placed into service after January 1, 1970 is inversely correlated with size. That is, the cost on a per kilowatt basis of installing a mechanical draft cooling tower at a large unit, other factors being equal, is typically less than that incurred by smaller units.

A 500 megawatt capacity unit's costs are approximately the average costs of all units included in the survey; costs will decline below the average as the size of the unit increases.

Units of this size which are now less than five years old may be expected to be operating for another 30 years. In view of this extensive remaining service life, the relatively lower retrofitting costs, and the larger volumes of heated water discharged, the Agency has concluded that the largest units coming on line since 1970 should be included while smaller units, of comparable age, should not.

(C) Capacity Utilization

All generating units do not produce power at their full capacity at all times. There are three major classifications of powerplants based on the degree to which their rated capacity is utilized on an annual basis. Baseload units are designed to run at near full capacity almost continuously. Peaking units are operated to supply electricity during periods of maximum system demand. Units which are operated for intermediate service between the extremes of baseload and peaking are termed cycling units.

Generally accepted definitions term units generating 60 percent or more of their annual capacity as baseload, those generating less than 20 percent as peaking, and those between 20 and 60 percent as cycling.

Most large units (over 300 megawatts capacity) are baseload units. Baseload units provide approximately 80 to 90 percent of the Nation's electric power and, account, therefore, for approximately the same percentage of waste heat. Because of their large size and high level of utilization, uncontrolled heated discharges from these units are generally considered to pose the greatest environmental risk. And because of their greater power output, the costs of retrofitting cooling systems to baseload units is considerably lower in mills per kilowatt hour than costs for peaking or cycling units.

Peaking units account for less than one percent of total effluent heat from the industry. Moreover, the cost per unit of production for thermal control is three to four times that of baseload costs. On this basis, commenters urged the Agency to exclude existing peaking and cycling units from thermal control and the Agency essentially has done so in the regulation promulgated today.

Though there is no explicit exemption based on capacity utilization, the combined effect of the exemptions predicated on age and size will effectively exclude almost all existing units operating at substantially reduced capacity factors.

Capacity utilization is related to age. With few exceptions, units begin operation as baseload units. As they become older and relatively less efficient, they are replaced by newer more efficient baseload units and reduced to cycling service. As they near the end of their service life they are employed as peaking units. By confining the coverage of the thermal limitations to units less than nine months old (except for those of 500 megawatts capacity or greater), the Agency has, in effect, excluded low capacity utilization units. Virtually all units which have come on line since January 1, 1970 which are in excess of 500 megawatts capacity are intended to be operated as baseload units at the time the conversion to closed-cycle must be effected.

(D) Units With Existing Closed-Cycle Cooling Systems

Some commenters suggested that units with existing closed-cycle systems employing hot-side blowdown be exempted from the requirement of cold-side blowdown.

The Agency agrees that incremental costs of converting to cold-side blowdown for units which already have closed-cycle systems employing hot-side blowdown is not justified in light of the small reduction in thermal discharge that would ensue.

(E) Salt Drift

Although the environmental effects of saltwater cooling towers vary from case to case depending on the sensitivity of local environment and diverse local meteorological conditions, experience with existing salt water cooling towers indicates that environmental problems would be confined to areas in close proximity to the cooling tower. One study showed that about 70 percent of all drift mass fell within 400 feet downwind of a typical saltwater mechanical draft tower, well within the boundaries of most powerplants. The same study showed that even under the most adverse conditions, all drift droplets that would reach the ground would do so within 1000 feet downwind. The subject of this study was an eight-cell crossflow mechanical draft tower designed to cool 134,000 gallons per minute of water with the same chemical composition and salinity as seawater. The plant was located on an estuary or bay, two miles from the ocean. The drift rate was 0.004 percent of the circulating water.

Airborne drift from this tower plus natural background salt nuclei from the sea exceeded conservative damage thresholds for foliar injury for distances up to 2200 feet downwind of the tower. The background salt nuclei contributed over 75 percent of the salt mass causing damage at this distance from the tower. Moreover, the fractional increase in airborne salt concentrations due to drift at 2200 feet was insignificant as compared with normal variations in the background level caused by changes in atmospheric wind conditions.

Obviously, local plant life in areas potentially affected by salt drift from towers must be capable of withstanding these natural airborne salt levels if they are to survive. Other possible recipients of incremental salt drift would likewise be affected by the natural ambient levels.

The additional cost of drift eliminators does not represent a significant increment to total cooling system cost and should be reflected in the cost estimates supplied by the industry for plants representing over 12 percent of the Nation's total generating capacity.

Potentially significant environmental damage over and above that from ambient conditions may be expected to be confined to areas in proximity to the tower and in the prevailing downwind direction. The regulation therefore provides an exemption where land not owned by the plant is located within 500 feet downwind of every practicable mechanical draft tower site using saline intake water and where no alternative closed cycle mode (such as natural draft towers which have significantly less drift loss) is practicable.

(F) Land Availability

Some comments urged that the Agency liberalize its exemption from thermal control for units which do not have sufficient land on which to construct the necessary evaporative cooling system, suggesting that where the costs of making land available raise the total cost of installing closed-cycle cooling above 1 mill per killowatt-hour the exemption should apply. Others recommended that, in order not to reward utilities for poor site planning, the determination of sufficient land include property within two miles of the unit whether owned by the utility or not, if it could be acquired.

The size of the evaporative cooling tower required is related to the generating capacity of the unit. Taking into account the other factors which can influence tower size (such as heat rate, climatic conditions, etc.) the Agency has determined that 28 acres per 1000 megawatts generating capacity is ample land on which any existing plant can construct a mechanical draft cooling tower, the cooling system which is most universally applicable and which provides the basis for the Agency's cost estimates. This conservative area-to-capacity standard is based on Federal Power Commission estimates of mechanical draft cooling tower land requirements and the Agency's review of mechanical draft cooling tower land use requirements at nuclear units, including sufficient allowances for construction and spacing between towers.

In determining whether sufficient land is available at a particular site the regulations require consideration of reassignment of present land uses (parking areas, for example) as well as the practicability of alternate evaporative cooling systems. Natural draft towers, for example, require less than 40 percent of the land needed for mechanical draft towers. The judgment of whether or not the reassignment of existing land is practicable cannot be reduced to a single cost per unit of output figure as suggested.

Moreover, in many cases adjoining land may be purchased at reasonable cost as an alternative to reassignment of existing land uses. Nevertheless, adjacent land costs could, in some instances, materially increase the cost of installing closed cycle systems. Hence, the promulgated regulations do not predicate the exemption from thermal limitations on the acquisition of neighboring land. Instead it is based solely on land owned or controlled by the owner or operator of the plant as of the date of proposal of this regulation.

(G) Aircraft Safety

Some comments urged the consideration of the possible hazard to aircraft of steam plumes issuing from cooling towers.

An examination of this potential hazard indicated that it is unlikely that an existing powerplant which will be required to install a recirculated cooling water system would pose a hazard to commercial aircraft during periods of takeoff and landing. However, the vulnerability of aircraft during this portion of the flight pattern requires special consideration of cases where a substantial hazard may be shown to exist. The promulgated regulation reflects this consideration.

The Agency considered exempting units discharging into oceans or coastal waters because of two reasons advanced in comments that were received. First, because of the greater dissipative capacity of oceans, heat discharges were said to be less likely to cause environmental damage. Second, the requirements of closed cycle cooling would exacerbate fresh water shortages which could be expected in certain coastal areas by the year 2000 during extreme low flow conditions.

No water shortage appears evident, or likely to ensue, by the end of the century in Washington, Oregon, Northern California, most Gulf Coast States, or the Atlantic Coast. Moreover, the projection of increased fresh water consumption was predicated on conversion of all existing coastal plants from once-through saline systems to fresh water evaporative towers and adoption of fresh water towers by all new ocean sited plants. Such an assumption is unrealistic, however, since salt water towers are presently in operation and available to coastal plants in arid areas.

Use of saline water in evaporative towers would, of course, have no effect on the supply of fresh water.

On the other hand, there is evidence to suggest that the discharge of heat into marine waters at sufficient depth and distance from biologically sensitive shoreline zones may pose considerably less of a threat to the environment than do thermal discharges into rivers, lakes and estuaries. But if the compatibility of thermal discharges with the environmental integrity of aquatic communities at particular sites can be demonstrated, a modification of the limitations on heat may be made through the procedures established by the Agency to implement section 316(a). The Agency recognized in the proposed regulation that artificial ponds built for cooling and located on the property of the utility constitute an acceptable process technology for the control of heat. In response to criticisms of the lack of clarity of the proposal, the regulation has been revised to make clear that existing units otherwise subject to a "no discharge" limitation on heat may discharge heat into existing cooling lakes and ponds. Definitions of each term have also been provided which differentiate between "cooling ponds" (artificial water bodies constructed by means other than impounding the flow of navigable water) and "cooling lakes" (artificial water bodies whose construction does entail blockage of navigable water flows). While new units whose cooling system involves creation of an "on stream" cooling lake would remain subject to the limitations on heat discharge from the condenser into such a projected impoundment, the provisions of section 316(a) would be available to such units. Chemical discharges into artificial water bodies which constitute navigable waters under the Act must comply with the limitations on pollutants other than heat.

The Agency is convinced that the electric utility industry has both the economic and technological capability to install closed cycle cooling systems on those units whose thermal discharges are controlled by this regulation and to do so by the compliance date established. The estimates of reduced reserve capacity submitted were, the Agency believes, over-stated since they assume that no units would obtain exemptions under section 316(a). Moreover, significant revisions to the proposed regulation have been made to insure that the required conversion to closed-cycle is realistic and that compliance with it entails no risk to the continued reliable supply of electric power. First, the number of units potentially subject to it has been reduced drastically. Second, the date by which the largest units are subjected to control has been extended by two years; the compliance date now being nearly seven years in the future. Finally, the permit issuing authority is authorized to defer compliance for an additional two years if, despite the above described revision, compliance by all units in a related system could, by virtue of outages during tie-in to the cooling system, seriously impact system reliability. This will permit each utility to plan, design, and construct off-stream cooling systems at the optimum time in accordance with planned maintenance schedules as well as in consideration of reliability factors.

The Agency has reviewed the significance of the numerous site-dependent factors both independently as well as their aggregate impact. A summary of its conclusions as to the collective significance of site dependent factors and each individual variable follows.

(A) Site-Dependent Factors in General

During the comment period, industry representatives supplied two sets of data on the cost of installation of mechanical draft cooling towers. The first was a report of an engineering firm experienced with the construction of cooling towers. Its estimate of the capital cost of retrofitting, on a per kilowatt basis, was only slightly higher than that used in the Agency's original cost estimates of the proposed regulation.

The second was based on a survey of 60 plants, in several utility systems, which represent approximately 12 percent of the total steam electric generating capacity in the United States. The average capital cost of this survey was significantly higher than the previous industry estimate; the disparity being accounted for by the commenter on the ground that the higher estimates reflected additional costs attributable to site-specific factors. The variability of the plant by plant costs reported in the latter survey approximates a normal distribution and ranges from about $9 per kilowatt to about $81 per kilowatt. The median of the sample and the capacity weighted average cost is $21.9 per kilowatt. The Agency adjusted its cost estimates of the economic impact of the final regulation to a figure closely approximating this industry-estimated cost. Only three of the plants reported per kilowatt costs significantly above the average value (in excess by 100 percent or more.) The few exceptions with extraordinarily high cost per kilowatt represent about 3 percent of the generating capacity covered by the sample. Since the extensive sample of cost estimates from individual plants addresses all site dependent factors in most instances, and includes to some extent costs corresponding to the factors addressed specifically below, EPA has determined that the sample adequately depicts the effects of the total of the site dependent factors that materially influence the costs of achieving the effluent limitations on heat. While the estimated costs of implementing thermal controls at three of the plants were reported to reflect costs in excess of twice the median cost, these incremental cost factors would not significantly affect the economic achievability of the effluent limitations. Favorable and unfavorable site-dependent factors may be expected to counterbalance one another, when applied across the several units at individual plants and the numerous plants in an electrical generating system. Hence, the average of the cost estimates reported in the 60 plant sample represents a realistic estimate of the retrofitting costs likely to be encountered by any utility system. Even in the extraordinary case of the one plant in the 60 plant sample reporting a cost estimate of $81 per kilowatt, the incremental cost (above that within which 95 percent of plants estimated costs reflecting site specific factors) would not affect the economic achievability of the thermal limitations. For example, the abnormal incremental costs at that site ($37 per kilowatt) would add about 1 mill per kilowatt-hour to the cost of electricity generated by that unit. Unusual compliance costs could impact the numerous small units or small systems more severely. Consequently, these units have been exempted categorically from the effluent limitations on heat.

(B) Type of Generation

In general, nuclear units reject more waste heat to condenser cooling water than do comparable fossil-fueled units. The Agency recognizes that the costs of installing thermal control technology are greater for units which reject more waste heat. Nevertheless, the cost differential due to type of generation is approximately equivalent to the additional waste heat discharged by nuclear plants and is within the range of costs reflecting the normal variability among site-dependent factors in general as discussed above. In either case, the costs per unit of heat removed by closed cycle cooling would be the same. Therefore, no distinction need be made between nuclear and fossil-fueled units.

Conversion of a nuclear unit from once-through cooling to a closed cycle system may entail associated modifications to the radioactive waste disposal system. Units employing once-through cooling normally discharge treated liquid radioactive wastes to the large volumes of non-recirculating cooling water, relying on dilution in that stream to meet water quality standards on the discharge of radioactive materials. The volume of the blowdown from closed cycle cooling may not provide sufficient dilution for this practice to be continued. However, in three cases in which closed cycle cooling systems were backfitted to nuclear powerplants, none of the additional costs for radioactive waste system modification were directly attributed to the closed cycle backfit by the U. S. Atomic Energy Commission in its final environmental statement. Since the Agency has received no specific cost information concerning radioactive waste system modification due to closed-cycle cooling system backfitting, no incremental costs for this potential modification have been included in the Agency's cost estimates.

(C) Flow Rate

The cost of closed-cycle cooling equipment and the total cost of generation are higher for units with higher flow rates, all other factors being equal. Flow rates for a particular unit can be reduced to some degree without significant incremental cost to achieve the reduced flow. In the cost analysis submitted to the Agency in support of the proposed subcategorization criteria, the cooling equipment costs for the cases of highest flow rate, all other factors being equal, were less than 10 percent higher than the average cost of all cases with various flow rates. Total generation cost were less than approximately 10 percent higher for the cases with the highest flow rates. In the cost analysis for the worst combination of intake temperature, wet-bulb temperature, and flow rate, the equipment cost exceeded the average equipment cost by 52 percent. These variations in equipment cost are within the range of variations in cost that are anticipated considering the numerous factors that combine, some favorably and some unfavorably, at each site to determine the final cost of thermal control implementation. A 10 percent cost differential is within the range of costs reflecting the normal variability among site-dependent factors in general as discussed above. Therefore, no distinction need be made for this factor.

(D) Heat Rate

Units with high heat rates would be the most costly to control due to the high incremental fuel cost associated with the increased inefficiency attributable to thermal controls. While no specific exemption is provided, exemptions based on age and size will exclude most of the units with high heat rates.

(E) Intake Temperature

EPA recognize that units with high intake water temperature will incur higher costs, all other factors being equal. This factor, however, is significant mainly during the months when the high intake water temperatures occur and also for those units for which high levels of blowdown flow are necessary, thus requiring relatively large quantities of makeup water. It is not as significant a factor for most units which require normal quantities of makeup water flow. In the cost analysis submitted to the Agency in support of the proposed subcategorization criteria, this factor all other factors being equal, added a maximum of 20 percent in the most extreme case to the average total thermal control equipment cost. This 20 percent cost differential is within the range of costs reflecting the normal variability among site-dependent factors in general as discussed above. Therefore, no distinction need be made for this factor.

(F) Wet-Bulb Temperature

EPA tested the significance of wet-bulb temperature as a factor by costing various types of evaporative cooling systems considering four geographic locations representative of the range of wet-bulb temperatures in the United States. The cost of cooling equipment at the most unfavorable location based on wet-bulb temperature was 25 percent higher than the average cost of all locations tested for conditions otherwise identical. In the cost analysis submitted to the Agency in support of the proposed subcategorization criteria, this factor, all other factors being equal, added a maximum of 24 percent to the total thermal control equipment cost for the average of subcases covered for the most costly case analyzed. This 24 percent cost differential is within the range of costs reflecting the normal variability among site-dependent factors in general as discussed above. Therefore, no distinction need be made for this factor.

(G) Back-End Loading

The back-end loading of a unit is the maximum steam flow which the unit can pass through the last stage blades of the low pressure turbine expressed as a percentage of the maximum steam flow through the last stage blades which the turbine is capable of accepting.

In the cost analysis submitted to the Agency in support of the proposed subcategorization criteria, this factor, all other factors being equal, added a maximum of 22 percent to the total thermal control equipment costs compared to the average of the cases covered. The maximum cost reflected the cost for a unit with a back-end loading of approximately 15 percent. Generation costs in mills per kilowatt-hour for the worst case of a 15 percent back-end loading were estimated to be about 1 mill per kilowatt-hour. This 22 percent differential in equipment costs is within the range of costs reflecting the normal variability among site-dependent factors in general, as discussed above. The worst case generation cost is in the range recommended by industry, therefore, no distinction need be made for this factor.

(H) Plume Abatement

Cooling towers can produce visible plumes consisting of minute water droplets. Plumes are normally not a problem unless they reach the ground and obstruct vision or cause icing conditions. Under normal conditions, cooling tower plumes rise due to their initial velocity and buoyancy and rarely intersect the ground before they are mixed with the ambient air and dissipated. However, under adverse climatic conditions (i.e., high humidity and low temperature), the moisture could produce a fog condition if it were trapped in the lower levels of the atmosphere during an inversion, i.e., a period of high atmospheric stability. In almost all cases, natural draft towers are less likely to cause fogging problems than mechanical draft towers. Even with mechanical draft towers, in most cases fogging or icing would be on-site (i.e., within 1000-2000 ft of the tower). Plume abatement technology, e.g., wet-dry cooling towers, is currently available. While wet-dry towers are more costly than conventional wet towers, the Agency has accounted for the cost of employing plume abatement in specific cases in its estimate of the cost of cooling tower construction. This estimate is based on cost data supplied by industry. The industry estimates, in turn, were developed from a sample of 60 plants and units and the costs for 18 of the units in the sample reflected the use of wet-dry towers. Hence, no specific exemption based on the potential for plume generation is warranted except where the plume presents a substantial hazard to aircraft flight paths.

(I) Noise Abatement Costs

EPA recognizes that incremental costs would be incurred in cases where mechanical draft cooling towers may require noise control. Little information is available on the cost of implementing noise control procedures on powerplant cooling towers principally because it has rarely been necessary to employ these measures, even though powerplants with cooling towers exist in areas of high population density. It is doubtful that there will be a significant need for this technology as a result of this regulation, since many plants in areas of high population density will be exempted because of the lack of sufficient land for closed-cycle cooling systems, because of the salt drift exemption, or because of the exemptions based on age or size. Furthermore, alternative thermal control technologies may be employed that are generally quieter than mechanical draft cooling towers. In the only case cited by commenters, a plant in West Germany was reputed to have incurred twice the normal capital cost for cooling towers due to the installation of noise control equipment. This is a most unusual case indeed. The plant cited is in West Berlin, a politically land locked community isolated from outside power sources. Increased demand and a paucity of available sites required that a new plant be constructed in close proximity to residences in an area of high population density, hence, the need for noise abatement technology. Furthermore, it is significant that cooling towers were employed with noise suppressors in order to take advantage of the site while accomodating the need to reduce noise to locally required levels.

(J) Miscellaneous Factors

Certain additional site-dependent factors have been suggested by commenters which should be considered in subcategorization for effluent limitations on heat because they can materially affect cost; existing system layout, soil conditions, site geology, and topography. While it is acknowledged that these factors may affect case-by-case costs, the costs attributable to these and other site-dependent factors have been assumed in the computation of the economic costs of thermal control. All evaporative heat rejection systems consume water. Even once-through systems result in water consumption by evaporation during the transfer of heat from the receiving water body to the atmosphere. Consumptive use of water by mechanical draft towers exceeds that of once-through systems by approximately 50-75 percent. Evidence received by the Agency suggested that were all existing and new plants covered by the proposed regulation to install close cycle cooling, the increase in water consumption by the year 2000 over that which would be consumed by extrapolation of the 1970 mix of cooling systems to the generating capacity expected to be on line in that year, would approximate 8.5 billion gallons per day. This projected increase, which was based on the assumption that no plants would qualify for an exemption under section 316(a) of the Act during the next 25 years, was conceded to be relatively insignificant compared to the total water available in the United States during average flow conditions. Federal Power Commission supplied estimates of water consumption attributable to closed cycling cooling suggest that the actual consumption may be significantly lower.

However, for certain regions, the projected increase when compared to the 10 and 20 years drought conditions, would increase water deficits assumed to exist even in the absence of closed cycle consumptive use. The regions of most concern are Southern California and the Texas Gulf.

Much of the 3.8 percent increase in deficit for California under the 20 year low flow conditions appears to be attributable to the assumption that coastal plants will convert to freshwater rather than saline towers. The deficiencies of this assumption have been discussed previously. In addition, however, the final regulation has been revised to exempt most units constructed before 1974 from thermal control. Virtually all presently operating coastal units (which represent nearly half of the present generating capacity in California) will thus be exempt. To the extent that expansion of generating capacity is composed of new coastal units, the utility is free to select sites at which the discharge would protect the balanced indigenous aquatic community, thus qualifying for exemptions under section 316(a) and avoiding any consumptive use of freshwater. Moreover, saltwater cooling towers could be used at coastal sites with the result that no freshwater would be consumed.

In other arid regions, such as Texas, use of closed-cycle evaporative cooling systems (both towers and cooling ponds) is already widespread for technological rather than environmental reasons, since the available surface water supply is not adequate for once-through cooling to be effective. Much of the increase in the projected consumptive use appears attributable to the assumption that cooling towers would have to be constructed at existing man made cooling lakes and offstream cooling ponds. The regulation has been revised to make clear that cooling lakes and ponds meeting certain specifications are considered acceptable heat abatement mechanisms and that towers need not be constructed if such a system is in operation.

Powerplants normally place generating units out of service on a scheduled basis for periods of a month or more in order to perform necessary maintenance. Units may also be shut down from time to time for unplanned maintenance. When units are shut down, the lost generating capacity is supplied by somewhat less efficient units within the system or by purchase of power from outside the system. The installation of new generating capacity in a system takes into account, on a projected basis, the user demand in its service area and such additional factors as scheduled outages and probabilities of unscheduled outages. A well-engineered retrofit design could be scheduled for tie-in to an existing system in from one week to five weeks of actual unit outage time. The regulation has been revised to exclude most existing units from thermal control and to defer the date of conversion for the remaining affected units from 1978 to 1981. Moreover, the final regulation incorporates commenters' suggestions for flexibility in further extending compliance dates in order to avoid adversely impacting regional reliability. The Agency has determined that tie-in outages can be scheduled concurrently with planned maintenance in such a manner that one month outage time would be required in addition to normal maintenance and that replacement power during this period can be supplied by the system's cycling units. Since no net loss in generating capacity need occur for closed-cycle tie-ins, there is no need for capital expenditures to be debited against outages during construction.

The Agency estimates that the effluent limitations on heat will increase the utility industry's capital requirements by an additional 5.2 billion dollars by 1983, without allowing for the reduction in capital cost which may be expected as a result of exemptions from the thermal limitations obtained under section 316(a). (These and all other estimates are expressed in constant 1974 dollars). The operating expenditures during the period 1974-1983 associated with the thermal limitations are estimated to be 1.3 billion dollars before 316(a) exemptions, an increase 0.4 percent of total industry operating expenses.

The fuel penalty associated with the thermal limitations consists of additional fuel required to operate the closed-cycle cooling system and additional fuel required per kilowatt-hour resulting from efficiency losses due to increased turbine back-pressure. The combined annual fuel penalty is approximately 3 percent. In addition, there will be a transient 2.1 percent fuel penalty associated with generation of interim replacement capacity during outages for conversion to closed cycle. The fuel penalty estimated represents approximately 16 million tons of coal (a 1.6 percent increase in projected 1983 coal consumption) and 44,000 barrels per day of oil (a 0.2 percent increase in projected 1983 oil consumption).

The effect of capital and generating costs for thermal control would increase the cost of electricity to consumers by a maximum of 2.2 percent by 1983. This price increase is not expected to have a significant affect on the growth of demand for electricity. Moreover, while the capital costs are substantial in absolute terms, they represent, without accounting for expected exemptions from thermal limitations, approximately 3 percent of the capital which the industry is planning to invest over the next decade for expansion of its generating capacity. The Agency has concluded that the industry will be able to obtain sufficient additional capital to finance the expenditures for water pollution control.

The costs of complying with the water pollution control requirements are not expected to have any effect on the production of electricity nor on employment in the industry.

SECTON XII

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Ernst I. Ewoldsen, Senior Mechanical Engineer
William A. Foy, Senior Environmental Engineer
Dr. Benjamin J. Intorre, Engineering Specialist
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Walter J. Hunt, Chief, Effluent Guidelines

Development Branch, EGD
Dr. Clark Allen, Region VI
Alden Christiansen, National Environmental Research
Center, Corvallis
Swepe Davis, Office of Planning and Management
Don Goodwin, Office of Air Quality Planning and Standards
William Jordan, Office of Enforcement and General Counsel
Charles Kaplan, Region IV
Steve Levy, Office of Solid Waste Management Programs
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Materials
John Lum, Region II
Dr. Guy R. Nelson, National Environmental Research
Center, Corvallis

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Dr. Eric Schneider, National Marine Water Quality Laboratory
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Dr. Bruce A. Tichener, National Environmental Research Center, Corvallis
Dennis Tihanjky, Office of Planning and Evaluation
Srini Vasan, Region V
Dr. Joseph V. Yance, Office of Water and Hazardous Materials
Michele Zarubica, Office of Planning and Evaluation

Additional comments were received from:

Effluent Standards and Water Quality Information Advisory Committee
Dr. William A. Brungs, National Water Quality Laboratory Duluth
Dr. W. D. Rowe, Office of Radiation Programs
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SECTION XIII

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SECTION XIV

GLOSSARY

Absolute Pressure

The total force per unit area measured above absolute vacuum as a reference. Standard atmospheric pressure is 101,326 N/sq m (14.696 psi) above absolute vacuum (zero pressure absolute).

Absolute Temperature

The temperature measured from a zero at which all molecular activity ceases. The volume of an ideal gas is directly proportional to its absolute temperature. It is measured in °K (°R) corresponding to °C + 273 (°F + 459).

Acid

A substance which dissolves in water with the formation of hydrogen ion. A substance containing hydrogen which may be displaced by metals to form salts.

Acidity

The quantitative capacity of aqueous solutions to react with hydroxyl ions (OH^-). The condition of a water solution having a pH of less than 7.

Agglomeration

The coalescence of dispersed suspended matter into larger flocs or particles which settle more rapidly.

Alkali

A soluble substance which when dissolved in water yields hydroxyl ions. Alkalies combine with acids to yield neutral salts.

Alkaline

The condition of a water solution having a pH concentration greater than 7.0, and having the properties of a base.

Alkalinity

The capacity to neutralize acids, a property imparted to water by its content of carbonates, bicarbonates, and hydroxides. It is expressed in milligrams per liter of equivalent $CaCO_3$.

Anion

The charged particle in a solution of an electrolyte which carries a negative charge.

Anthracite

A hard natural coal of high luster which contains little volatile matter.

Approach Temperature

The difference between the exit temperature of water from a cooling tower, and the wet bulb temperature of the air.

Ash

The solid residue following combustion of a fuel.

Ash Sluice

The transport of solid residue ash by water flow in a conduit.

Backwash

Operation of a granular fixed bed in reverse flow to wash out sediment and reclassify the granular media.

Bag Filters

A fabric type filter in which dust laden gas is made to pass through woven fabric to remove the particulate matter.

Base

A compound which dissolves in water to yield hydroxyl ions (OH^-).

Base-load Unit

An electric generating facility operating continuously at a constant output with little hourly or daily fluctuation.

Biocide

An agent used to control biological growth.

Bituminous

A coal of intermediate hardness containing between 50 and 92 percent carbon.

Blowdown

A portion of water in a closed system which is wasted in order to prevent a build-up of dissolved solids.

BOD

Biochemical oxygen demand. The quantity of oxygen required for the biochemical oxidation of organic matter in a sewage or industrial waste in a specific time, at a specified temperature and under specified conditions. A standard test to assess wastewater pollution level.

Boiler

A device in which a liquid is converted into its vapor state by the action of heat. In the steam electric generating industry the equipment which converts water into steam.

Boiler Feedwater

The water supplied to a boiler to be converted into steam.

Boiler Fireside

The surface of boiler heat exchange elements exposed to the hot combustion products.

Boiler Scale

An incrustation of salts deposited on the waterside of a boiler as a result of the evaporation of water.

Boiler Tubes

Tubes contained in a boiler through which water passes during its conversion into steam.

Bottom Ash

The solid residue left from the combustion of a fuel, which falls to the bottom of the combustion chamber.

Brackish Water

Water having a dissolved solids content between that of fresh water and that of sea water, generally from 1000 to 10,000 mg per liter.

Brine

Water saturated with a salt.

Bus Bar

A conductor forming a common junction between two or more electrical circuits. A term commonly used in the electric utility industry to refer to electric power leaving a station boundary. Bus bar costs would refer to the cost per unit of electrical energy leaving the station.

Capacity Factor

The ratio of energy actually produced to that which would have been produced in the same period had the unit been operated continuously at rated capacity.

Carbonate Hardness

Hardness of water caused by the presence of carbonates and bicarbonates of calcium and magnesium.

Cation

The charged particles in solution of an electrolyte which are positively charged.

Chemical Oxygen Demand (COD)

A specific test to measure the amount of oxygen required for the complete oxidation of all organic and inorganic matter in a water sample which is susceptible to oxidation by a strong chemical oxidant.

Circulating Water Pumps

Pumps which deliver cooling water to the condensers of a powerplant.

Circulating Water System

A system which conveys cooling water from its source to the main condensers and then to the point of discharge. Synonymous with cooling water system.

Clarification

A process for the removal of suspended matter from a water solution.

Clarifier

A basin in which water flows at a low velocity to allow settling of suspended matter.

Closed Circulating Water System

A system which passes water through the condensers, then through an artificial cooling device, and keeps recycling it.

Coal Pile Drainage

Runoff from the coal pile as a result of rainfall.

Condensate Polisher

An ion exchanger used to adsorb minute quantities of cations and anions present in condensate as a result of corrosion and erosion of metallic surfaces.

Condenser

A device for converting a vapor into its liquid phase.

Construction

Any placement, assembly or installation of facilities or equipment (including contractual obligations to purchase such facilities or equipment) at the premises where the equipment will be used, including preparation work at the premises.

Convection

The heat transfer mechanism arising from the motion of a fluid.

Cooling Canal

A canal in which warm water enters at one end, is cooled by contact with air, and is discharged at the other end.

Cooling Tower

A configured heat exchange device which transfers reject heat from circulating water to the atmosphere.

Cooling Tower Basin

A basin located at the bottom of a cooling tower for collecting the falling water.

Cooling Water System

See Circulating Water System

Corrosion Inhibitor

A chemical agent which slows down or prohibits a corrosion reaction.

Counterflow

A process in which two media flow through a system in opposite directions.

Critical Point

The temperature and pressure conditions at which the saturated-liquid and saturated-vapor states of a fluid are identical. For water-steam these conditions are 3208.2 psia and 705.47°F.

Cycling Plant

A generating facility which operates between peak load and base load conditions.

Cyclone Furnace

A water-cooled horizontal cylinder in which fuel is fired, heat is released at extremely high rates, and combustion is completed. The hot gases are then ejected into the main furnace. The fuel and combustion air enter tangentially imparting a whirling motion to the burning fuel, hence the name Cyclone Furnace. Molten slag forms on the cylinder walls, and flows off for removal.

Deaeration

A process by which dissolved air and oxygen are stripped from water either by physical or chemical methods.

Deaerator

A device for the removal of oxygen, carbon dioxide and other gases from water.

Degasification

The removal of a gas from a liquid.

Deionizer

A process for treating water by removal of cations and anions.

Demineralizer

See Deionizer

Demister

A device for trapping liquid entrainment from gas or vapor streams.

Dewater

To remove a portion of the water from a sludge or a slurry.

Dew Point

The temperature of a gas-vapor mixture at which the vapor condenses when it is cooled at constant humidity.

Diesel

An internal combustion engine in which the temperature at the end of the compression is such that combustion is initiated without external ignition.

Discharge

To release or vent.

Discharge Pipe or Conduit

A section of pipe or conduit from the condenser discharge to the point of discharge into receiving waters or cooling device.

Drift

Entrained water carried from a cooling device by the exhaust air.

Dry Bottom Furnace

Refers to a furnace in which the ash is collected as a dry solid in hoppers at the bottom of the furnace, and removed from the furnace in this state.

Dry Tower

A cooling tower in which the fluid to be cooled flows within a closed system. This type of tower usually uses finned or extended surfaces.

Dry Well

A dry compartment of a pump structure at or below pumping level, where pumps are located.

Economizer

A heat exchanger which uses the heat of combustion gases to raise the boiler feedwater temperature before the feedwater enters the boiler.

Electrostatic Precipitator

A device for removing particles from a stream of gas based on the principle that these particles carry electrostatic charges and can therefore be attracted to an electrode by imposing a potential across the stream of gas.

Evaporation

The process by which a liquid becomes a vapor.

Evaporator

A device which converts a liquid into a vapor by the addition of heat.

Feedwater Heater

Heat exchangers in which boiler feedwater is preheated by steam extracted from the turbine.

Filter Bed

A device for removing suspended solids from water, consisting of granular material placed in a layer(s) and capable of being cleaned hydraulically by reversing the direction of the flow.

Filtration

The process of passing a liquid through a filtering medium for the removal of suspended or colloidal matter.

Fireside Cleaning

Cleaning of the outside surface of boiler tubes and combustion chamber refractories to remove deposits formed during the combustion.

Floc

Small gelatinous masses formed in a liquid by the reaction of a coagulant added thereto, thru biochemical processes, or by agglomeration.

Flue Gas

The gaseous products resulting from the combustion process after passage through the boiler.

Fly Ash

A portion of the non-combustible residue from a fuel which is carried out of the boiler by the flue gas.

Fossil Fuel

A natural solid, liquid or gaseous fuel such as coal, petroleum or natural gas.

Generation

The conversion of chemical or mechanical energy into electrical energy.

Heat Rate

The fuel heat input (in Joules or Btus) required to generate a kwh.

Heating Value

The heat available from the combustion of a given quantity of fuel as determined by a standard calorimetric process.

Humidity

Pounds of water vapor carried by 1 lb of dry air.

Ion

A charged atom, molecule or radical, the migration of which affects the transport of electricity through an electrolyte.

Ion Exchange

A chemical process involving reversible interchange of ions between a liquid and a solid but no radical change in the structure of the solid.

Lignite

A carbonaceous fuel ranked between peat and coal.

Makeup Water Pumps

Pumps which provide water to replace that lost by evaporation, seepage, and blowdown.

Mechanical Draft Tower

A cooling tower in which the air flow through the tower is maintained by fans. In forced draft towers the air is forced through the tower by fans located at its base, whereas in induced draft towers the air is pulled through the tower by fans mounted on top of the tower.

Mill

One thousandth of a dollar.

Mine-mouth Plant

A steam electric powerplant located within a short distance of a coal mine and to which the coal is transported from the mine by, a conveyor system, slurry pipeline or truck.

Mole

The molecular weight of a substance expressed in grams (or pounds).

Name Plate

See Nominal Capacity

Natural Draft Cooling Tower

A cooling tower through which air is circulated by a natural or chimney effect. A hyperbolic tower is a natural draft tower that is hyperbolic in shape.

Neutralization

Reaction of acid or alkaline solutions with the opposite reagent until the concentrations of hydrogen and hydroxyl ions are about equal.

New Source

Any source, the construction of which is commenced after the publication of proposed Section 306 regulations, (March 4, 1974 for the Steam Electric Power Generating Point Source Category).

Nominal Capacity

Name plate - design rating of a plant, or specific piece of equipment.

Nuclear Energy

The energy derived from the fission of nuclei of heavy elements such as uranium or thorium or from the fusion of the nuclei of light elements such as deuterium or tritium.

Once-through Circulating Water System

A circulating water system which draws water from a natural source, passes it through the main condensers and returns it to a natural body of water.

Overflow

(1) Excess water over the normal operating limits disposed of by letting it flow out through a device provided for that purpose; (2) The device itself that allows excess water to flow out.

Osmosis

The process of diffusion of a solvent through a semi-permeable membrane from a solution of lower to one of higher concentration.

Osmotic Pressure

The equilibrium pressure differential across a semi-permeable membrane which separates a solution of lower from one of higher concentration.

Oxidation

The addition of oxygen to a chemical compound, generally any reaction which involves the loss of electrons from an atom.

Package Sewage Treatment Plant

A sewage treatment facility contained in a small area and generally prefabricated in a complete package.

Packing (Cooling Towers)

A media providing large surface area for the purpose of enhancing mass and heat transfer, usually between a gas or vapor, and a liquid.

Peak-load Plant

A generating facility operated only during periods of maximum demand.

Penalty

A sum to be forfeited, or a loss due to some action.

pH Value

A scale for expressing the acidity or alkalinity of a solution. Mathematically it is the logarithm of the reciprocal of the gram ionic hydrogen equivalents per liter. Neutral water has a pH of 7.0 and hydrogen ion concentration of 10^{-7} moles per liter.

Placed in Service

Refers to the date when a generating unit initially generated electrical power to service customers.

Plant Code Number

A four-digit number assigned to all powerplants in the industry inventory for the purpose of this study.

Plume (Gas)

A conspicuous trail of gas or vapor emitted from a cooling tower or chimney.

Powerplant

Equipment that produces electrical energy generally by conversion from heat energy produced by chemical or nuclear reaction.

Precipitation

A phenomenon that occurs when a substance held in solution in a liquid phase passes out of solution into a solid phase.

Preheater (Air)

A unit used to heat the air needed for combustion by absorbing heat from the products of combustion.

Psychrometric

Refers to air-water vapor mixtures and their properties. A psychrometric chart graphically displays the relationship between these properties.

Pulverized Coal

Coal that has been ground to a powder, usually of a size where 80 percent passes through a #200 U.S.S. sieve.

Pyrites

Combinations of iron and sulfur found in coal as FeS_2.

Radwaste

Radioactive waste streams from nuclear powerplants.

Range

Difference between entrance and exit temperature of water in a cooling tower.

Rank of Coal

A classification of coal based upon the fixed carbon on a dry weight basis and the heat value.

Rankine Cycle

The thermodynamic cycle which is the basis of the steam-electric generating process.

Recirculation System

Facilities which are specifically designed to divert the major portion of the cooling water discharge back for reuse.

Reduction

A chemical reaction which involves the addition of electrons to an ion to decrease its positive valence.

Regeneration

Displacement from ion exchange resins of the ions removed from the process solution.

Reheater

A heat exchange device for adding superheat to steam which has been partially expanded in the turbine.

Reinjection

To return a flow, or portion of flow, into a process.

Relative Humidity

Ratio of the partial pressure of the water vapor to the vapor pressure of water at air temperature.

Reverse Osmosis

The process of diffusion of a solute through a semi-permeable membrane from a solution of lower to one of higher concentration, affected by raising the pressure of the less concentrated solution to above the osmotic pressure.

Saline Water

Water containing salts.

Sampling Stations

Locations where several flow samples are tapped for analysis.

Sanitary Wastewater

Wastewater discharged from sanitary conveniences of dwellings and industrial facilities.

Saturated Air

Air in which water vapor is in equilibrium with liquid water at air temperature.

Saturated Steam

Steam at the temperature and pressure at which the liquid and vapor phase can exist in equilibrium.

Scale

Generally insoluble deposits on heat transfer surfaces which inhibit the passage of heat through these surfaces.

Scrubber

A device for removing particles or objectionable gases from a stream of gas.

Secondary Treatment

The treatment of sanitary waste water by biological means after primary treatment by sedimentation.

Sedimentation

The process of subsidence and deposition of suspended matter carried by a liquid.

Sequestering Agents

Chemical compounds which are added to water systems to prevent the formation of scale by holding the insoluble compounds in suspension.

Service Water Pumps

Pumps providing water for auxiliary plant heat exchangers and other uses.

Slag Tap Furnace

Furnace in which the temperature is high enough to maintain ash (slag) in a molten state until it leaves the furnace through a tap at the bottom. The slag falls into the sluicing water where it cools, disintegrates, and is carried away.

Slimicide

An agent used to destroy or control slimes.

Sludge

Accumulated solids separated from a liquid during processing.

Softener

Any device used to remove hardness from water. Hardness in water is due mainly to calcium and magnesium salts. Natural zeolites, ion exchange resins, and precipitation processes are used to remove the calcium and magnesium.

Spinning Reserve

The power generating reserve connected to the bus bar and ready to take load. Normally consists of units operating at less than full load. Gas turbines, even though not running, are considered spinning reserve due to their quick start up time.

Spray Module (Powered Spray Module)

A water cooling device consisting of a pump and spray nozzle or nozzles mounted on floats and moored in the body of water to be cooled. Heat is transfered principally by evaporation from the water drops as they fall through the air.

Station

A plant comprising one or several units for the generation of power.

Steam Drum

Vessel in which the saturated steam is separated from the steam-water mixture and into which the feedwater is introduced.

Supercritical

Refers to boilers designed to operate at or above the critical point of water 22,100 kN/sq m and 374.0°C (3206.2 psia and 705.4°F).

Superheated Steam

Steam which has been heated to a temperature above that corresponding to saturation at a specific pressure.

Thermal Efficiency

The efficiency of the thermodynamic cycle in producing work from heat. The ratio of usable energy to heat input expressed as a percent.

Thickening

Process of increasing the solids content of sludge.

Total Dynamic Head (TDH)

Total energy provided by a pump consisting of the difference in elevation between the suction and discharge levels, plus losses due to unrecovered velocity heads and friction.

Turbidity

Presence of suspended matter such as organic or inorganic material, plankton or other microscopic organisms which reduce the clarity of the water.

Turbine

A device used to convert the energy of steam or gas into rotational mechanical energy and used as prime mover to drive electric generators.

Unit

In steam electric generation, the basic system for power generation consisting of a boiler and its associated turbine and generator with the required auxiliary equipment.

Utility

(Public utility) A company either investor-owned or publicly owned which provides service to the public in general. The electric utilities generate and distribute electric power.

Volatile Combustion Matter

The relatively light components in a fuel which readily vaporize at a relatively low temperature and which when combined or reacted with oxygen, give out light and heat.

Wet Bottom Furnace

See slag-tap furnace.

Wet Bulb Temperature

The steady-state, nonequilibrium temperature reached by a small mass of water immersed under adiabatic conditions in a continuous stream of air.

Wet Scrubber

A device for the collection of particulate matter from a gas stream or absorption of certain gases from the stream.

Zeolite

Complex sodium aluminum silicate materials, which have ion exchange properties and were the original ion exchange materials before synthetic resins were processed.

APPENDIX 1

INVENTORY NOTES

1. Unless otherwise noted, the generating capacity given is the installed capacity based on Federal Power Commission data of June 30, 1970, updated to January 1, 1972 through the Electrical World Directory of Electric Utilities, 1972-1973, published by McGraw-Hill, Inc.

2. Plants under construction are indicated by (*).

3. Plant types indicated are as follows:
    - F - Fossil fuel plant
    - N - Nuclear plant
    - G - Gas turbine unit within a fossil fuel plant

4. Unless otherwise indicated 60 Hz is the frequency of electricity generated.

EPA REGION I

Region: Connecticut, Maine, Massachusetts
New Hampshire, Rhode Island, Vermont

Region Office: Boston, Massachusetts

CONNECTICUT

Utility	Plant	Location	Gen.Capacity (MW)	Type
Conn. Light & Power Company	Devon	Milford	454	F
			16.3	G
	Montville	Montville	577.4	F
	Norwalk Harbor	Norwalk	326.4	F
			16.3	G
	Millstone Point	Waterford	661.5	N
Conn. Yankee Atomic Power Co.	Conn. Yankee Atomic	Haddam	600.0	N
Hartford Electric Light Company	Middletown	Middletown	422	F
			18.6	G
	Stamford	Stamford	52.5	F
	South Meadow	Hartford	216.8	F
	Millstone No. 2	Waterford	180	G
			828	N
Norwich Department Of Pub. Utilities	Norwich	Norwich	14.3	F
United Illuminating Company	English Plant	New Haven	163.2	F
	Steel Point	Bridgeport	174.5	F
	Bridgeport Harbor	Bridgeport	660.5	F
			18.6	G
	Derby Station	Derby	20.0	F
U. S. Navy	New London Sub. Base	New London	10.5	F
Wallingford Electric Div.	Alfred L. Pierce	Wallingford	22.5	F

EPA REGION I

NEW HAMPSHIRE

Utility	Plant	Location	Gen.Capacity (MW)	Type
Public Service Co. of New Hampshire	Daniel Street	Portsmouth	21	F
	Kelley Falls	Manchester	18.8	F
	Manchester Steam	Manchester	20	F
	Merrimack	Bow	459	F
	Schiller	Portsmouth	37.2	G
			178.8	F

RHODE ISLAND

Utility	Plant	Location	Gen.Capacity (MW)	Type
Blackstone Valley Electric Co.	Pawtucket	Pawtucket	33.5	F
The Narragansett Electric Co.	South Street	Providence	188.6	F
	Manchester Street	Providence	132	F
Newport Electric Corp	Newport	Newport	11.0	F
U. S. Navy	Quonset Point		5.0	F

VERMONT

Utility	Plant	Location	Gen.Capacity (MW)	Type
Burlington Electric Light Dept.	J. Edward Moran	Burlington	30	F
			28	G
Central Vermont Public Service Co.	Milton Steam	St. Albans	4.0	F
	Rutland		31.2	F
Vermont Yankee Nuclear Power Corp.	Vermont Yankee	Vernon	513	N

EPA REGION I

MAINE

Utility	Plant	Location	Gen.Capacity (MW)	Type
Bangor Hydro Electric Company	Graham	Bangor	57.5	F
			12.0	G
Central Maine Power Company	Cape	South Portland	22.5	F
	Mason	Wiscasset	146.5	F
	W. F. Wyman	Yarmouth	213.6	F
Maine Public Service Co.	Caribou	Caribou	19	F
Maine Yankee Atomic Power Co.	Bailey Point No. 1		855*	N
U. S. Navy	Kittery		7	F
			4.3	F

MASSACHUSETTS

Utility	Plant	Location	Gen.Capacity (MW)	Type
Boston Edison Co.	New Boston Sta.No. 400	South Boston	717.75	F
	L Street Sta. No. 4	South Boston	153.75	F
			18.6	G
	Edgar Station No. 75	N. Weymouth	457.9	F
			33.5	G
	Mystic Sta. No. 200	Everett	618.8	F
			16.8	F
	Leland St.Sta.No. 240	Framingham	33.5	F
	Pilgrim		650*	N
Braintree Electric Light Dept.	Allen Street	Braintree	21.0	F
	N.P. Potter	Braintree	12.5	F
Brockton Edison Co.	East Bridgewater	East Bridgewater	20	F
Cambridge Electric Light Company	Blackstone Street	Cambridge	24.8	F
	Kendell Square	Cambridge	67.5	F
Canal Electric Co.	Canal	Sandwich	542.5	F

EPA REGION I

MASSACHUSETTS (continued)

Utility	Plant	Location	Gen.Capacity MW	Type
Fall River Electric Light Company	Hathaway Street	Fall River	14.3	F
Fitchburg Gas & Electric Light Co.	Sawyer Passway	Fitchburg	61.4	F
Holyoke Munic. Gas & Electric Dept.	Holyoke	Holyoke	30	F
			10	G
Holyoke Water Power Co.	Mt. Tom Power Plt.	Holyoke	136	F
	Riverside Station	Holyoke	44.8	F
Mass. Bay Trans. Authority	South Boston		120	F
	Lincoln		60	F
Mass. Electric Co.	Webster Street	Worcester	34.5	F
	Lynnway	Lynn	49.0	F
Montaup Electric Co.	Somerset Station	Fall River	344	F
			48	G
New Bedford Gas & Edison Light Co.	Cannon Street	New Bedford	115.5	F
New England Power Co.	Salem Harbor	Salem	319.9	F
	Brayton Point	Somerset	1124.7	F
Taunton Municipal Lighting Plant	Westwater Street	Taunton	49	F
	B. F. Cleary	Taunton	28.3	F
U. S. Navy	Boston Navy Yard		22	F
Western Massachusetts Electric Co.	West Springfield	West Springfield	209.6	F
			18.6	G
Yankee Atomic Electric Co.	Yankee Atomic	Rowe	185	N

EPA REGION II

Region: New Jersey, New York, Puerto Rico, Virgin Islands

Region Office: New York, New York

NEW JERSEY

Utility	Plant	Location	Gen. Capacity MW	Type
Atlantic City Elec. Co.	Missouri Ave.	Atlantic City	50	F
			55.8	G
	Deepwater	Penns Grove	308.3	F
			18.6	G
	Greenwich	Gibbstown	10	F
	B.L. England	Beesleys Pt.	299.2	F
Jersey Central Power & Light Company	E. H. Werner	South Amboy	116.3	F
	Sayreville	Sayreville	343.8	F
	Oyster Creek	Lacey Township	640	N
New Jersey Power & Light Company	Gilbert	Milford	126.1	F
Public Service Elec. & Gas Company	Bergen	Ridgefield	640.4	F
			18.6	G
	Burlington	Burlington	490.5	F
	Essex	Newark	329	F
			417	G
	Hudson	Jersey City	1114.5	F
			115.2	G
	Kearny	Kearny	598.5	F
			311.2	F
	Linden	Linden	519.4	F
			113.8	G
	Marion	Jersey City	125	F
	Mercer	Hamilton	652.8	F
			115.2	G
	Sewaren	Sewaren	820	F
			115.2	G
	Salem 1		1090*	N
	Salem 2		1115*	N
Vineland Electric Utility	Vineland	Vineland	67.3	F

EPA REGION II

NEW YORK

Utility	Plant	Location	Gen. Capacity MW	Type
Central Hudson Gas & Electric Corp.	Danskammer Point	Roseton	531.9	F
			5.5	G
	Riverside	Poughkeepsie	12	F
Consolidated Edison Co. of N. Y., Inc.	Arthur Kill	New York	911.7	F
			16.3	G
	Astoria	Queen	1550.6	F
			496	G
			119.8	G
	East River	New York	773.7	F
			60	F 25 Hz
	Hell Gate	New York	541.3	F
			70	F 25 Hz
Consolidated Edison Co. of N. Y.	Hudson Ave.	Brooklyn	845	F
			846	G
	Indian Point	New York	275	N
			2138*	N
	Kent Avenue	Brooklyn	107.5	F 25 Hz
			28	G
	Ravenswood	New York	1827.7	F
			481.8	G
	Sherman Creek	New York	216.5	F
	Waterside # 1 & 2	New York	140	F 25 Hz
			572.3	F
			14	G
	74th Street	New York	125	F 25 Hz
			144	F
			37.2	G
	59th Street	New York	184.5	F 25 Hz
			34.2	G
Jamestown Board of Public Utilities	Samuel A. Carlson	Jamestown	82.5	F
Lawrence Park Heat, Light & Power Co.	Lawrence Park	Lawrence Park	1.1	F

EPA REGION II

NEW YORK (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Long Island Lighting Co.	E. F. Barret	Island Park	375	F
			258	G
	Glenwood	Glenwood Landing	403	F
	Port Jefferson	Port Jefferson	467	F
			16	G
	Far Rockaway	Far Rockaway	113.6	F
	Northport	Northport	774.2	F
			387.0*	F
			16	G
New York State Elec. & Gas Corporation	Goudey	Johnson City	145.8	F
			30.0	F
	Greenridge	Dresden	160	F
	Jennison	Bainbridge	60	F
	Hickling	East Corning	70	F
	Milliken	Ludlowville	270	F
	Bell	Near Ludlowville	853*	N
Niagara Mohawk Power Corp.	Albany	Albany	400	F
			155	G
	Charles L. Huntley	Buffalo	828	F
			0.7	G
	Dunkirk	Dunkirk	628	F
	Nine Mile Point	Oswego	642	N
			5.7	G
	Oswego	Oswego	376	F
			0.7	G
Orange & Rockland Utilities Inc.	Lovett	Tomkins Cove	489.5	F
	Bowlin	Near New Milford	1246*	F
Power Authority State of N. Y.	J.A. Fitzpatrick	Oswego	800*	N

EPA REGION II

NEW YORK (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Rochester Gas & Elec. Corp.	Rochester #3	Rochester	206.2	F
			18.0	G
	Rochester #7	Greece	252.6	
	Rochester #8	Rochester	8	F
	Rochester #9	Rochester	3	F
	Rochester #12	Ontario	420	F
	Ginna R.G.	Rochester	517.1	N
U.S. Military Academy (Light & Power Plant)	Light Power U.S. Military Academy	West Point,N.Y.	4.5	F

PUERTO RICO

Utility	Plant	Location	Gen. Capacity MW	Type
Puerto Rico Water Resources Auth.	San Juan	San Juan	640	F
			30	G
	South Coast	Guayanilla	287.5	F
			10	G
			820*	F
			40	G
	Palo Seco	Catano	657	F
			30	G
U.S. Navy	Ceiba	Ceiba	8	F

VIRGIN ISLANDS

Utility	Plant	Location	Gen. Capacity MW	Type
Virgin Island Water & Power Authority	St. Thomas/ St Johns	Virgin Island	29.2	F
			15.1	G
	St. Croix	Virgin Island	25.5	F
			18	G

EPA REGION III

Region: Delaware, Maryland, Pennsylvania, Virginia
West Virginia, District of Columbia

Region Office: Philadelphia, Pennsylvania

DELAWARE

Utility	Plant	Location	Gen. Capacity MW	Type
Delmarva Power & Light Co.	Delaware City	Delaware City	130	F
			18.6	G
	Indian River	Millsboro	330.2	F
			18.6	G
	Edge Moore	Edge Moore	389.8	F
			15	G
			378*	F
Dover Munic. Power Plant	McKee Runn	Dover	37.5	F
	St. Jones River	Dover	8.8	F

MARYLAND

Utility	Plant	Location	Gen. Capacity MW	Type
Baltimore Gas & Elec. Co.	Westport	Baltimore	194	F
			121.5	G
	Gould Street	Baltimore	173.5	F
	Pratt Street	Baltimore	20	F
	Riverside	Baltimore	333.5	F
			173.5	G
	Wagner, Herbert, A.	Baltimore	627.8	F
			16	G
			414.7*	F
	Crane P. Charles	Baltimore	399.8	F
	Calvert Cliffs	Nr. Annapolis	16	G
			1804*	N
Delmarva Power & Light Co. of Maryland	Vienna	Vienna	244.5	F
			18.6	G
Hagerstown Munic. Elec. and Light Plant	Hagerstown	Hagerstown	38.8	F

MARYLAND (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
The Potomac Edison Co.	Smith, R . Paul	Williamsport	159.5	F
	Cumberland	Cumberland	30	F
	Celanese	Amcella	10	F
Potomac Elec. Power Co.	Dickerson	Dickerson	586.5	F
			16.2	G
	Chalkpoint	Aquasco	726.6	F
			16.1	G
	Morgantown	Newburg	1146	F
			35.8	G

PENNSYLVANIA

Utility	Plant	Location	Gen. Capacity MW	Type
Chambersburg Municipal Electric Dept.	Chambersburg	Chambersburg	15	F
Duguesne Light Co.	Elrama	Elrama	525	F
	Frank R. Phillips	Wireton	411.2	F
	James H. Reed	Pittsburg	180	F
	Colfax	Cheswick	262.5	F
	Shippingport	Shippingport	100	N
	Cheswick	Springdale	525	F
Lansdale Elec. Dept.	Lansdale	Lansdale	24.5	F
			11.3	G
Metropolitan Edison Co.	Portland	Portland	426.7	F
			37.6	G
	Titus	Reading	225	F
			18	G
	Crawford	Middletown	116.8	F
	Eyler	Reading	84	F
	Three Mile Island	Nr. Harrisburg	1780*	N

EPA REGION III

PENNSYLVANIA (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Pennsylvania Power Co.	New Castle	West Pittsburgh	425.8	F
Pennsylvania Power & Light Co.	Burner Island	York Haven	1577.7	F
			1064*	F
	Holtwood	Holtwood	105	F
	Keystone Plant	Schelocta	1872	F
	Martins Creek	Martins Creek	312.5	F
			5	G
	Stanton	Harding	140.5	F
	Sunbury	Shamokin Dam	409.8	F
			6.0	G
	Suburban		29.3	F
	Montour	Washingtonville	822.7*	F
Philadelphia Elec. Co.	Schuylkill	Philadelphia	50.0	F 25 Hz
			275.4	F
			18.6	G
	Chester	Chester	256	F
			55.8	G
	Delaware	Philadelphia	439.3	F
			76.2	G
	Richmond	Philadelphia	594.0	F
			487.2	G
Philadelphia Elec. Co.	Barbadoes	Norristown	155	F
			65.4	G
	Southwark	Philadelphia	345	F
			74.4	G
	Cromby	Phoenixville	417.5	F
			275	G
	Eddystone	Eddystone	707.2	F
			37.2	G
	Peach Bottom 1	Delta	40	N
	Peach Bottom 2		1098.3*	N
	Peach Bottom 3		1065*	N
	Limerick 1	Philadelphia	1065*	N
	Limerick 2		1065*	N
U.G.I. Corporation	Hunlock Creek	Hunlock	93.0	F

PENNSYLVANIA (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Pennsylvania Elec. Co.	Shawville	Shawville	640	F
	Seward	Seward	268.3	F
	Warren	Warren	73.4	F
	Front Street	Erie	118.8	F
	Saxton	Saxton	30	F
	Williamsburg	Williamsburg	39	F
	Homer City	Homer City	1320	F
	Conemaugh		936	F
			936*	F
Pennsylvania State Uni.	Central	University Park	7.5	F
Quakertown Mun. System	Generating plant	Quakertown	9.9	F
Saxton Experimental Corp.	Saxton		10	N
Weatherly Borough Elec. Dept.	Weatherly	Weatherly	1.5	F
West Penn Power Co.	Springdale	Springdale	416	F
	Mitchell	Courtney	448.7	F
	Armstrong	Reesedale	326.4	F
	Milesburg	Milesburg	46	F
	Hartfield's Ferry	Mansontown	576	F
			1000*	F

VIRGINIA

Utility	Plant	Location	Gen. Capacity MW	Type
Appalachian Power Co.	Glen Lyn	Glen Lyn	401.1	F
	Clinch River	Cleveland	669	F
The Potomac Edison Co. of Virginia	Riverton	Riverton	34.5	F
Virginia Elec. & Power Co.	Bremo	Bremo Bluff	284.3	F
	Chesterfield	Chester	1434.5	F
	Portsmouth	Norfolk	649.6	F
			195.4	G

EPA REGION III

VIRGINIA (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Virginia Elec. & Power Co.	Possum Point	Dumfries	491	F
			96	G
	Reeves Ave.	Norfolk	100	F
	12th Street	Richmond	102.5	F
	Yorktown	Hornsbyville	375	F
			845*	F
	Surry		1600*	N
	North Anna	Nr. Richmond	1750*	N
Danville Water,Gas & Electric Dept.	Brantley Steam St.		29.0	F
Virginia Polytechnic Heat & Power Plant	VPI Central Heat		1.8	F
Potomac Electric Power Co.	Potomac River	Alexandria	514.8	F
U. S. Navy	Portsmouth		27	F
Davi (MUN)	Brantley		29	F

WEST VIRGINIA

Utility	Plant	Location	Gen. Capacity MW	Type
Monongahela Power Co.	Albright	Albright	263	F
	Riversville	Riversville	174.8	F
	Willow Island	Willow Island	215	F
	Fort Martin	Maidsville	1152	F
	Harrison	Shinnston	1950*	F
Appalachian Power Co.	Kanahwa River	Glasgow	426	F
	Cabin Creek	Cabin Creek	273.6	F
	Philip Sporn	New Haven	1960	F
	John Amos	Winfield	2950	F
Ohio Power Co.	Krammer	Captina	675	F
	Windsor	Power	300	F
	Mitchell	Captina	1600	F

* under construction

WEST VIRGINIA (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Virginia Elec. & Power Co.	Mount Storm	Mount Storm	1140.5	F
			18.6	G
			555*	F

DISTRICT OF COLUMBIA

Utility	Plant	Location	Gen. Capacity MW	Type
Potomac Elec. Power Co.	Benning	Washington	553.6	F
			289*	
			50	F 25 Hz
	Buzzard Point	Washington	270	F
			288	G

EPA REGION IV

Region: Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee

Region Office: Atlanta, Georgia

ALABAMA

Utility	Plant	Location	Gen.Capacity MW	Type
Alabama Elec.Coop.,Inc.	McWilliams	Andalusia	40	F
			11.05	G
	Tombigee	Leroy	75	F
Alabama Power Co.	Barry	Bucks	1770	F
			60	G
	Chickasaw	Chickasaw	138	F
	Gorgas	Gorgas	756	F
	Gadsden 1 & 2	Gadsden	138	F
	Green County	Demopolis	568.5	F
	Farley Unit 1	Nr.Cedar Springs	820*	N
	Farley Unit 2	" " "	820*	N
Southern Elec.Gen. Co.	Gaston C. Ernest	Wilsonville	1060.8	F
			850	F
			21.3	G
Tennesee Valley Auth.	Colbert	Pride	1396.5	F
	Widows Creek	Bridgeport	1978	F
	Brown's Ferry	Near Decatur	3456*	N

FLORIDA

Utility	Plant	Location	Gen.Capacity MW	Type
Florida Pwr. & Light Co.	Sanford	Sanford	156.3	F
	Palatka	Palatka	109.5	F
	Fort Myers	Fort Myers	558.3	F
	Port Everglades	Port Everglades	1254.6	F
	Lauderdale	Dania	312.5	F
	Riviera	Riviera	739.6	F
	Miami	Miami	46	F
	Cutler	Cutler	346.3	F
	Cape Kennedy	Cape Kennedy	804	F
	Turkey Point	Florida City	817.5	F
	Turkey Point, 3 & 4	Nr. Miami	1456.6*	N
	Hutchinson Island	Hutchinson Is.	892.5*	N
	Fort Pierce	Fort Pierce	1500*	N

FLORIDA (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Florida Power Corp.	Bayboro	St. Petersburg	51.3	F
	Paul L. Bartow	St. Petersburg	494.4	F
			-	G
	Higgins	Oldsmar	138	F
			131.9	G
	Inglis	Inglis	53.8	F
	Suwannee River	Live Oak	147	F
	Avon Park	Avon Park	61	F
	George E. Turner	Enterprise	201.6	F
			34	
	Crystal River	Red Level	964.3	F
	Port St. Joe	Port St. Joe	40.5	F
	Rio Pinar	Rio Pinar	15	F
	Anclote	Tarpon Springs	886*	N
Florida Public Utiilites	Marianna	Marianna	2.0	F
Gulf Power Co.	Crist	Pennsecola	651	F
			578*	F
	Lansing Smith	Pannama City	340	F
			40	G
	Scholz	Chattahoochee	98	F
Tampa Elec. Co.	Big Bend	Tampa	869.2	F
			18	G
	Hookers Point	Tampa	232.6	F
	Francis J. Gannon	Tampa	1270.4	F
			18	G
	Peter O. Knight	Tampa	60	F
Gainsville Utilities	John R. Kelly	Gainsville	99	F
			43.5	G
	DeErhaven	Hague	81	F
Jacksonville Elec. Auth.	J. Dillon Kennedy	Jacksonville	356.6	F
			40	G
	Northside	Jacksonville	560	F
			32.9	G
	Southside	Jacksonville	356.6	F
			34	G

FLORIDA (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Key West Utility Board	City Elect. System	Key West	70	F
Lakeland Dept. of Elec. & Water Utilities	Larsen Memorial	Lakeland	120	F
			33.8	G
	Power Plant #3	Lakeland	90	F
	Lake Mirror	Lakeland	10	F
New Smyrna Utilities	Swoope	New Smyrna Beach	7.5	F
Tallahassee Elec. Dept.	S. O. Purdom	St. Marks	130	F
			25	H
	Aruah B. Hopkins	Tallahassee	80.9	F
			17.0	G
Vero Beach Mun. Utilities	Vero Beach	Vero Beach	62	F
Orlando Utilities Comm.	Orlando	Titusville	294.3	F
			317*	F
	Lake Highland	Orlando	103.8	F

GEORGIA

Utility	Plant	Location	Gen. Capacity MW	Type
Georgia Power Co.	Arkwright	Macon	181.3	F
			32.6	G
	Atkinson	Smyrna	258	F
			83.7	G
	Bowen	Catersville	771.6	F
			39.4	G
	Hammond	Coosa	953	F
	Harlee Branch	Milledgeville	1539.7	F
	Jack McDonough	Smyrna	598.4	F
			80	G
	McManus	Brunswick	143.8	F
			159	G
	Mitchell	Albany	218.3	F

EPA REGION IV

GEORGIA (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Georgia Power Co.	Yates	Newman	680	F
	Etowah		2470*	F
			40	G
	Hatch	Nr. Jessup	1701*	N
	Wansley		1760*	F
Savannah Elec. & Power Co.	Riverside	Savannah	111	F
	Port Wentworth	Port Wentworth	207.9	F
			21.6	G
			120.3	F
	Effingham	Nr. Guyton	158*	F
Thomasville Water & Light	Thomasville	Thomasville	15.5	F
Crisp Co. Power Comm.	Crisp	Warwick	10.0	F

KENTUCKY

Utility	Plant	Location	Gen. Capacity MW	Type
Kentucky Utilities Co.	Green River	Central City	236.7	F
	Tyrone	Versailles	137.5	F
	E. W. Brown	Burgin	724.1	F
	Pieneville	Four Mile	37.5	F
	Ghent	Nr. Madison	500	F
	Haefling	Lexington	51	F
Louisville Gas & Elec. Co.	Canal	Louisville	50	F
	Cane Run	Louisville	1016.7	F
			16.3	G
	Paddy's Run	Louisville	337.5	F
			48.5	G
	Millcreek	Louisville	642.2*	F
Owensboro Mun. Utilities	Owensboro	Owensboro	52.5	F
	Elmer Smith	Owensboro	151	F
			265	F

EPA REGION IV

KENTUCKY (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Henderson Mun. Light	Henderson	Henderson	50.6	F
			2	G
Big River Rural Elec.	Robert Reid	Sabree	80	F
	Coleman	Hanesville	340	F
			160	G
E. Kentucky Rural Elec.	Wm. C. Dale	Ford	196	F
	Cooper John Sherman	Burnside	322	F
	Ohio River	Near Boone	450*	F
Tennessee Valley Auth.	Paradise	Paradise	2558.2	F
	Shawnee	Paducah	1750	F
Kentucky Power Co.	Big Sandy	Louisa	1003	F

MISSISSIPPI

Utility	Plant	Location	Gen. Capacity MW	Type
Mississippi Power & Light	Rex Brown	Jackson	383.2	F
			10	G
	Delta	Cleveland	220.5	F
	Natchez	Natchez	66	F
	Baxter Wilson	Vicksburg	544.6	F
			700	F
Greenwood Utilities	Wright	Greenwood	23.5	F
	Henderson	Greenwood	12.6	F
			11.5	G
Yazoo City - Public Service Commission	Yazoo City	Yazoo City	19	F
			12.5	G
South Mississippi Elec. Power Association	Moselle	Hattiesburg	177	F
Clarksdale Public Utility Commission	Clarksdale	Clarksdale	29.5	F
			14.3	G

EPA REGION IV

NORTH CAROLINA

Utility	Plant	Location	Gen. Capacity MW	Type
Carolina Power & Light	Cape Fear	Moncure	421	F
			72	G
	H. F. Lee	Goldsboro	402.5	F
			16.3	G
			89.9	G
	W. H. Weatherspoon	Lumberton	165.5	F
			79.5	G
	Louis V. Sutton	Wilmington	225	F
			91.3	G
			420*	F
	Asheville	Asheville	206.6	F
			200.0	F
	Roxboro	Roxboro	1067.8	F
			720*	F
			16.3	G
	Brunswick	Tranquil Harbor	1642*	N
Duke Power Co.	Riverbend	Mount Holly	631	F
			120	G
	Buck	Spencer	440	F
			112.5	G
	Dan River	Draper	290	F
			85	G
	Cliffside	Cliffside	210	F
			570*	F
	Allen	Belmont	1155	F
	Marshall	Terrell	200	F
	Belews Creek	Near Greensboro	2160*	F
	McGuire	Near Mooresville	2300*	N

EPA REGION IV

SOUTH CAROLINA

Utility	Plant	Location	Gen. Capacity MW	Type
Lockhart Power Co.	Lockhart	Lockhart	5	F
South Carolina Elec. & Gas Co.	McMeekin	Irmo	293.8	F
	Hagood	Charleston	94.4	F
	Canadys	Canady	489.6	F
			16.3	G
			34.5	G
	Urquhart	Beech Island	250	F
			75.8	G
	Parr	Parr	72.5	F
			74	G
	Wateree	Wateree	700	F
	Buahy Park	Nr. Moncks Corner	550*	F
			60	G
So. Carolina Public Service Authority	Jefferies	Moncks Corner	272.8	F
			172.8	F
	Grainger	Conway	163.2	F
Duke Power Co.	Lee	Pelzer	345	F
			90	G
	Tiger	Duncan	30.0	F
	Buzzard Roost	Chappels	16.1	F
			196	G
Greenwood Mills	Melhews No. 1	Greenwood	25	F
	Melhews No. 2	Greenwood	32.5	F
Carolina Power & Light	H. B. Robinson	Hartsville	206	F
			21.3	G
			700	N
	Brunswick 1 & 2	Wilmington	1641*	N

EPA REGION IV

TENNESSEE

Utility	Plant	Location	Gen. Capacity MW	Type
Tennessee Valley Auth.	Thomas H. Allen	Memphis	990	F
	Bull Run	Clinton	950	F
	Gallatin	Gallatin	1255.2	F
	John Sevier	Rogersville	823.3	F
	Johnsonville	New Johnsonville	1485.2	F
	Kingston	Kingston	1700	F
	Walts Bar	Walts Bar Dam	240	F
	Cumberland	Cumberland	2600*	F
	Seguoyah	Daisy	2441.2*	N

EPA REGION V

Region: Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin

Region Office: Chicago, Illinois

ILLINOIS

Utility	Plant	Location	Gen. Capacity MW	Type
Central Ill. Light Co.	R. S. Wallace	East Peoria	351.4	F
	Liberty Street	Peoria	25	F
	E. D. Edwards	South of Peoria	416	F
			350*	F
	Keystone	Bartonville	54.4	F
Central Illinois Public Service Co.	Coffeen	Coffeen	389	F
			600*	F
	Grand Tower	Grand Tower	232.66	F
	Hutsonville	Hutsonville	212.5	F
	Meredosia	Meredosia	354.4	F
Commonwealth Edison Co.	Ridgeland	Stickney	690	F
	Powerton	Pekin	315	F
			840*	F
	Joliet	Joliet	1862	F
			144	G
	Fisk	Chicago	546.6	F
			25	F
			226.1	G
	Dresden Nuclear #1	Morris	208	N
	Dresden #2 & 3	Morris	1620	N
	Fordom	Rockford	75.3	F
	Crawford	Chicago	701.5	F
			192	G
	Calumet	Chicago	174	F
			292	G
	Waukegan	Waukegan	1042	F
			113	G
	Dixon	Dixon	119	F
	Will County	Joliet	1258.9	F
	Sabrooke	Rockford	196.4	F
			148	G

ILLINOIS (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Commonwealth Edison Co.	Kincaid	Kincaid	1319.4	F
	Quad Cities	Near Albany	1618*	N
	Zion	Waukegan	2100*	N
	LaSalle County	Seneca	1156*	N
			1078*	N
Electric Energy, Inc.	Joppa	Elen	1100	F
Illinois Power Co.	Havana	Havana	230	F
	Hennepin	Hennepin	306.3	F
	Vermilion	Oakwood	182.3	F
			15.0	G
	Wood River	East Alton	650	F
	Baldwin	Baldwin	623	F
			1246.1*	F
Mt. Carmel Public Utility Co.	Mt. Carmel	Mt. Carmel	20.5	F
Carlyle Municipal Utilities	Carlyle	Carlyle	3	F
Highland Electric Light Dept.	Highland	Highland	12.5	F
Mascoutah Munic. Light & Water Dept.	Mascoutah	Mascoutah	1	F
McLeansboro Munic. Light & Power Plant	McLeansboro	McLeansboro	0.75	F
Rochelle Municipal Utilities	Rochelle	Rochelle	12.5	F
Springfield Water, Light & Power Dept.	Lakeside	Springfield	155	F
	Dallman	Springfield	70.2	F

EPA REGION V

ILLINOIS (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Winnetka Municipal Electric & Water Dept.	Winnetka	Winnetka	25.5	F
Southern Illinois Power Cooperative	Marion	South of Marion	94	F
Western Illinois Power Cooperative, Inc.	Pearl	Jacksonville	27.2	F
University of Illinois	Abbott	---	27.2	F
Union Electric Co.	Cahokia	Sauget	304	F
	Venice No. 1 & 2	Venice	529	F
Peru Light Dept.	Peru	Peru	15.3	F
Iowa-Illinois Gas & Electric Company	Moline	Moline	99.1	F
Chicago, Metropolitan Sanitary District	Chicago	Chicago	30.5	F

INDIANA

Utility	Plant	Location	Gen. Capacity MW	Type
Indiana & Michigan Electric Co.	Twin Branch	Mishawka	384	F
	Tanners Creek	Lawrenceburg	1098	F
	Breed	Sullivan	450	F
Indianapolis Power & Light Company	H. T. Pritchard	Martinsville	393.6	F
	Elmer W. Stout	Indianapolis	372.6	F
	C. C. Perry (Sec. K)	Indianapolis	47.5	F
	C. C. Perry (Sec. W)	Indianapolis	11	F
	Petersburg	Petersburg	724.4	F

INDIANA (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
North Indiana Public Service Company	Michigan City	Michigan City	211	F
	Dean H. Mitchell	Gary	529.4	F
			52.2	G
	Bailly	Dune Acres	615.6	F
			33.9	G
			535*	F
Public Service Co. of Indiana, Inc.	Dresser	Terre Haute	210	F
	Edwardsport	Edwardsport	146.8	F
	Noblesville	Noblesville	100	F
	Wabash River	West Terre Haute	962	F
			8	G
	Robert A. Gallagher	New Albany	600	F
	Rushville	Rushville	8.25	F
	Cayuga	Cayuga	500	F
			500*	F
Southern Indiana Gas & Electric Company	Ohio River	Evansville	121.5	F
	Culley	Newburgh	153.7	F
			250*	F
	Warrick Unit #4	Yankeetown	150	F
Logansport Municipal Utilities	Logansport	Logansport	55.5	F
			18	G
Peru Electric Light & Power Dept.	Peru	Peru	40	F
Indiana Statewide Rural Electric Corp., Inc.	Petersburg	Petersburg	200*	F
Indiana-Kentucky Electric Corp.	Clifty Creek	Madison	1303.6	F
Frankfort Light & Power Dept.	Frankfort	Frankfort	32.5	F
			16.5	G

EPA REGION V

INDIANA (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Crawfordsville Elec. Light & Power Co.	Crawfordsville	Crawfordsville	40.2	F
Commonwealth Edison Co. of Indiana, Inc.	State line	Hammond	972	F
Richmond Power and Light Dept.	Whitewater Valley	Richmond	30	F
	Johnson Street	Richmond	30	F
		Richmond	66*	F

MICHIGAN

Utility	Plant	Location	Gen. Capacity MW	Type
Consumer Power Co.	John C. Weadock	Essexville	614.5	F
			20.6	G
	Saginaw River	Saginaw	100	F
	Dane E. Karn	Essexville	530	F
			615*	F
	Bryce E. Morrow	Comstock	186	F
			35	G
	Kalamazoo	Kalamazoo	20	F
	Elm Street	Battle Creek	30	F
	Justin R. Whiting	Erie	325	F
			20.6	G
	B. C. Cobb	Muskegon	510.5	F
	Wealthy Street	Grand Rapids	20	F
	J. H. Campbell	West Olive	650	F
			20.6	G
	Big Rock	Charlevoix	75	N
	Palisades	Palisades	811.7*	N
	Midland	Free Pond	1381.3*	N

EPA REGION V

MICHIGAN (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Detroit Edison Co.	Beacon St.	Detroit	27.8	F
	St. Clair	Bell River	1905	F
			18.6	G
	River Rouge	River Rouge	933.2	F
	Greenwood Energy Center	Detroit	800*	N
	Conners Creek	Detroit	585	F
	Trenton Channel	Trenton	1075.5	F
	Delray	Detroit	391	F
	Marysville	Marysville	300	F
	Pennsalt	Wyandotte	37	F
	Wyandotte North	Wyandotte	54.1	F
	Wyandotte South	Wyandotte	18.5	F
	Port Huron	Port Huron	11.75	F
	Harbor Beach	Harbor Beach	121	F
	Monroe	Monroe	3000*	F
	Fermi	Detroit	158	N
			64	G
			1075*	N
	French Island		136	F
Indiana & Michigan Power Co.	Donald C. Cook	Bridgman	2200*	N
Upper Peninsula Power Co.	Escanaba	Escanaba	25.3	F
	John H. Warden	L'Anse	15.6	F
	Presque Isle	Marquette	174.7	F
			170*	F
Coldwater Board of Public Utilities	Coldwater	Coldwater	11.125	F
Detroit Public Lighting Commission	Mistersky	Detroit	174	F
Escanaba Municipal Electric Utility	Escanaba	Wells	25	F

MICHIGAN (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Grand Haven Board of Light & Power	Island Steam Plant	Grand Haven	20	F
Holland Board of Public Works	James De Young	Holland	77.2	F
Lansing Board of Water and Light	Ottawa	Lansing	81.5	F
	Eckert	Lansing	381	F
	Delta	Lansing	160*	F
Marquette Board of Light & Power	Marquette Gen.Plt.	Marquette	34.5	F
Traverse City Light & Power Dept.	Traverse City Plt.	Bay	35	F
Northern Michigan Electric Coop., Inc.	Advance	Boyne City	41.8	F
Michigan State Univ.	Sixty-five	East Lansing	31	F
Wyandotte Munic. Service Commission	Wyandotte	Wyandotte	41.5	F
			23	G

MINNESOTA

Utility	Plant	Location	Gen. Capacity MW	Type
Minnesota Power & Light Co.	Aurora	Aurora	116.1	F
	Clay Boswell	Cohasset	150	F
	M. L. Hibbard	Duluth	122.5	F
Northern State Power Co. (Minn.)	Black Dog	Nichols	480.7	F
	High Bridge	St. Paul	458.8	F
	Island	St. Paul	16	F

EPA REGION V

MINNESOTA (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Northern State Power Co. (Minn.)	King	Bayport	598.4	F
	Monticello	Monticello	569	N
	Red Wing	Red Wing	28	F
	Minnesota Valley	Granite Falls	65	F
	Riverside	Minneapolis	506.4	F
	South East	Minneapolis	30	F
	Whitney	St. Cloud	21	F
	Wilmarth	Mankato	25	F
	Winona	Winona	26	F
	Prairie Island	Near Hasting	1186*	N
Otter Tail Power Co.	Crockston	Crockston	10	F
	Hoot Lake	Fergus Falls	136.9	F
	Canby	Canby	7.5	F
	Ortonville	Ortonville	15	F
	Bemidji	Bemidji	37	F
Alexandria Board of Public Works	Alexandria	Alexandria	5.25	F
Austin Utilities	Austin	Austin	27.5	F
			6	G
			30	N
Benson Water & Light Dept.	Benson	Benson	0.45	F
Blue Earth Power & Water Dept.	Blue Earth	Blue Earth	5.0	F
Detroit Lakes Public Utilities Dept.	Detroit Lakes	Detroit Lakes	6.0	F
Fairmount Public Utilities Commission	Fairmount	Fairmount	26.5	F
Jackson Electric Light Dept.	Jackson	Jackson	2.0	F

MINNESOTA (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Litchfield Public Utilities Commission	Litchfield	Litchfield	3.5	F
Luverne Municipal Util.	Luverne	Luverne	3.0	F
Madison Munic. Util.	Madison	Madison	1.85	F
Marshall Munic. Util.	Marshall	Marshall	3.0	F
			16.5	G
Moorhead Public Service Dept.	Moorhead	Elm St. South	34	F
			10	G
Mountain Iron (MUN)	Mountain Iron	Mountain Iron	1.2	F
New Ulm Public Util. Commission	New Ulm	New Ulm	27	F
Owatonna Municipal Public Utilities	Owatonna	Owatonna	34.5	F
Redwood Falls Public Utilities Comm.	Redwood	Redwood Falls	2.0	F
Rochester Public Utility Dept.	Rochester	Rochester	113	F
Sleepy Eye Munic.Util.	Sleepy Eye	Sleepy Eye	3.25	F
Springfield Pub. Util.	Springfield	Springfield	2.75	F
Two Harbor Municipal Water & Light Plant	Two Harbors	Two Harbor	6.0	F
Virginia Dept. of Public Utilities	Virginia	Virginia	34.5	F

EPA REGION V

MINNESOTA (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Willmar Municipal Utilities Commission	Willmar	Willmar	32.4	F
Windom Munic. Util.	Windom	Windom	3.0	F
Worthington Munic. Public Utilities	Worthington	Worthington	16.5	F
Northern Minn. Power Association	Kettle River	Kettle River	4.25	F
Rural Cooperative Power Assn.	Elk River	Elk River	45.0	F
			22	N
			17.2	G
Interstate Power Co.	Albert Lea	Albert Lea	18.5	F
	Fox Lake	Sherburn	104	F

OHIO

Utility	Plant	Location	Gen. Capacity MW	Type
Cincinnati Gas & Electric Co.	West End	Cincinnati	219.3	F
	Miami Fort	North Bend	519.2	F
			182	G
	W. C. Beckjord	New Richmond	760.5	F
			460.8*	F
	J. M. Suaurt	Aberdeen	1830	F
			610*	F
	Zimmer	Near Berlin	1756*	N
Cleveland Electric Illuminating Co.	Ashtabula	Ashtabula	456	F
	Avon Lake	Avon Lake	1275	F
	East Lake	East Lake	577	F
			680*	F
	Lake Shore	Cleveland	514	F

EPA REGION V

OHIO (continued)

Utilities	Plant	Location	Gen. Capacity MW	Type
Columbus & Southern Ohio Electric Co.	Poston	Athens	232	F
			13.8	G
	Conesville	Conesville	433.5	F
			842*	F
			13.8	G
	Picway	Columbus	230.8	F
			251.28	G
	Walnut	Columbus	75	F
			65.3	G
The Dayton Power & Light Co.	Miamisburg	Miamisburg	6.4	F
	J. M. Straut	Aberdeen	610.2	F
	Frank M. Tait	Dayton	444.1	F
	O. H. Hutchings	Dayton	414	F
			32.6	G
	Troy	Troy	24	F
Ohio Edison Company	W. H. Sammis	Stratton	1979	F
			323*	F
	R. E. Burger	Shady Side	544	F
	Toronto	Toronto	315.8	F
	Niles	Niles	250	F
	Edgewater	Lorain	174.9	F
	Gorge	Akron	87.5	F
	Mad River	Springfield	75	F
	Scioto	Scioto	40.3	F
Ohio Power Company	Muskingum River	Beverly	1466.8	F
	Woodcock	Bluffton	42.5	F
	Tidd	Brilliant	222.2	F
	Philo	Philo	500	F
	Cardinal	Brilliant	1270.5	F
	Genl.James M.Gavin	Near Gallipolis	2600*	F
	Caldwell	Caldwell	2.8	F
	Martins Ferry	Martins Ferry	6.5	F
			2.0	G

EPA REGION V

OHIO (continued)

Utility	Plant	Location	Gen. Capacity MW	Type	
Ohio Valley Elec. Corp.	Kyger Creek	Gallipolis	1086.3	F	
Toledo Edison Co.	Bay Shore	Oregon	639.5	F	
			16	G	
	Acme	Toledo	307	F	25 Hz
			30	F	
	Clyde	Clyde	1	F	
	Davis-Beese	Toledo	2	F	
			870*	N	
Cleveland Div. of Light & Power	Lake Rd.	Cleveland	172.5	F	
	East 53rd St.	Cleveland	50	F	
	West 41st St.	Cleveland	35.6	F	
Columbus Munic. Electric Light Dept.	Columbus	Columbus	43.5	F	
			14.5	G	
Celina Munic. Util.	Celina	Celina	25	F	
			20*	G	
Dover Electric Dept.	Dover	Dover	33.2	F	
East Palestine Munic. Elect. Dept.	East Palestine	East Palestine	16.5	F	
Hamilton Dept. of Public Utilities	Hamilton	Hamilton	84	F	
			28.9	G	
Napoleon Munic. Util.	Napoleon	Napoleon	22.65	F	
Norwalk Municipal Elect. Dept.	Woodlawn Ave.	Norwalk	31.3	F	
Orriville Munic. Util.	Orriville	Orriville	38.5	F	
			62.5*	F	
Painesville Electric Power Dept.	Painesville	Painesville	38	F	

EPA REGION V

OHIO (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Piqua Munic. Power Plant	Piqua	Piqua	53	F
Reading Municipal Water and Light Plant	Prospect	Reading	9.5	F
			14*	F
St. Marys Munic. Light & Power	St. Marys	St. Marys	22	F
Shelby Munic. Elect. Plant	Shelby	Shelby	26.5	F
			12.5*	F
			3	G
			2600*	N

WISCONSIN

Utility	Plant	Location	Gen. Capacity MW	Type
Lake Superior District Power Co.	Bay Front	Ashland	82.2	F
Madison Gas & Elect.Co.	Blount	Madison	195.5	F
Northern States Power Co. (Wisconsin)	Edison	La Crosse	5	F
	French Island	La Crosse	25	F
	Sherbourne		1360*	
Superior Water, Light & Power Co.	Winslow	Superior	25.2	F
Wisconsin Electric Power Co.	Lakeside	St. Francis	344.7	F
	Commerce	Milwaukee	35	F
	East Wells	Milwaukee	13.7	F
	Port Washington	Port Washington	400	F
	Port Washington	Port Washington	19	G
	North Oak Creek	Oak Creek	500	F
	South Oak Creek	Oak Creek	1170	F
			19	G

EPA REGION V

WISCONSIN (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Wisconsin Electric Power Co.	Valley	Milwaukee	269.7	F
	Point Beach	Two Creeks	19.6	F
	Point Beach 1 & 2	Manitowoc	1005.7	N
Wisconsin Power & Light Company	Edgewater	Sheboygan	351	F
			129	F
	Rock River	Beloit	159.4	F
			46.8	G
	Black Hawk	Beloit	57.5	F
	Nepson Devy	Cassville	227.3	F
	Kewaunee	Kewaunee	527*	N
	Columbia	Near Portage	527*	F
Wisconsin Public Service Corp.	Pulliam	Green Bay	392.5	F
	Weston	Rothschild	135	F
			19.6	G
Manitowoc Public Util.	Manitowoc	Manitowoc	75	F
Marshfield Electric & Water Dept.	Wildwood	Marshfield	50.2	F
Menasha Electric & Water Utilities	Menasha	Menasha	29.2	F
Richland Center Munic. Utilities	Richland Center	Richland Center	14.2	F
Dairyland Power Coop.	Alma	Alma	187	F
	Stoneman	Cassville	51.8	F
	Genoa St. #1	Genoa	14.0	F
	Genoa St. #2	Genoa	50	N
	Genoa St. #3	Genoa	300	F
Oconto Elec. Coop.	Stiles	Stiles	1	F

EPA REGION VI

Region: Arkansas, Louisiana, New Mexico, Texas, Oklahoma

Region Office: Dallas, Texas

ARKANSAS

Utility	Plant	Location	Gen. Capacity MW	Type
Arkansas Power & Light Co.	Robert Ritchie	Helena	903.6	F
			18	G
	Lake Catherine	Hot Springs	756.0	F
	Cecil Lynch	N. Little Rock	259.8	F
	Harvey Couch	Stamps	187.5	F
	Hamilton Moses	Forest City	138	F
	Russellville	Russellville	793*	N
			920*	N
Hope Water & Light Plt.	Hope	Hope	6	F
Jonesboro Water & Light Plant	Jonesboro	Jonesboro	27.7	F
Arkansas Electric Coop. Corp.	Fitzhugh	Ozark	59.8	F
	Bailey	Augusta	122	F
			200*	F
	McClellan	Camden	134	F

LOUISIANA

Utility	Plant	Location	Gen. Capacity MW	Type
Central Louisiana Elec. Co., Inc.	Coughlin	St. Landry	483.3	F
	Teche	Baldwin	428	F
	Little Gypsy	La Place	1250.8	F
	Nine Mile Point	Westwego	1101	F
	Sterlington	Sterlington	351.5	F
New Orleans Public Service, Inc.	Mark St. Station	New Orleans	96.3	F
	A. B. Patterson	New Orleans	218.3	F
	Michoud	New Orleans	959.3	F

EPA REGION VI

LOUISIANA (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Southwestern Electric Power Co.	Arsenal Hill	Shreveport	170.0	F
	Liberman	Mooringsport	277.3	F
Alexandria Munic. Power & Light Dept.	Alexandria	Alexandria	97.5	F
			80*	F
Homer Light & Power Dept.	Homer	Homer	8.7	F
Houma Munic. Light Plt.	Houma	Houma	40.7	F
Lafayette Util. System	Rodemacher	Lafayette	45.7	F
	Louis "Doc" Bonin	Lafayette	143.3	F
Minden Light & Power Dept.	Minden	Minden	25	F
Monroe Util. Comm.	Park Ave.	Monroe	172	F
			10	G
Morgan City Munic. Electric Plant	Morgan	Morgan City	31	F
Natchitoches Munic. Elec. Light & Water	Natchitoches	Natchitoches	55.8	F
Ruston Munic. Light Dept.	Ruston	Ruston	41.4	F
Opelousas Munic. Elec. Dept.	Opelousas	Opelousas	12.7	F
			26*	F
Plaquemine Light Dept.	Plaquemine	Plaquemine	20.5*	F
			10.8	G
New Orleans Sewage & Water Board	Power House No. 2	New Orleans	47.0	F-25 Hz
			20	G-25 Hz

LOUISIANA (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Gulf State Utilities Co.	Louisiana St. #1&2	Baton Rouge	428	F
	Roy S. Nelson	Westlake	920.5	F
	Willow Glen	St. Gabriel	994.4	F
			530*	F
	River Bend #1&2	Baton Rouge	1880*	N
Louisiana Electric Coop., Inc.	New Roads	Near Morganza	230*	F

NEW MEXICO

Utility	Plant	Location	Gen. Capacity MW	Type
New Mexico Electric Service Co.	Maddox	Hobbs	118	F
Public Service Co. of New Mexico	Reeves	Albuquerque	175	F
	Person	Albuquerque	125	F
	Prager	Albuquerque	35	F
	Santa Fe	Santa Fe	12	F
Clayton Municipal Electric System	Clayton	Clayton	4	F
Farmington Electric Utility	Animas	Farmington	28.5	F
The Raton Public Service Company	Raton	Raton	12	F
Lea County Electric Cooperative, Inc.	Lea County	N. Lovington	59.6	F
Plains Elec. Generation & Trans. Coop., Inc.	Plains	Algodones	51.8	F

NEW MEXICO (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Southwestern Public Service Co.	Cunningham	Hobbs	265.4	F
	Carlsbad	Carlsbad	44.3	F
	Roswell	Roswell	24.2	F
			11.5	G
Arizona Public Service Co.	Four Corners	Nr.Farmington	2369.8	F
U.S. Atomic Energy Commission	TA-3	Los Alamos	20	F
Gallup Electric Light & Power System	Gallup	Gallup	16.1	F

TEXAS

Utility	Plant	Location	Gen. Capacity MW	Type
Central Power & Light Co.	La Palma	San Benito	217	F
	Victor P.S.	Victoria	553.5	F
	Nueces Bay	Corpus Christi	244.5	F
	Lon C. Hill	Calallen	574.2	F
	Laredo P.S.	Laredo	72	F
	J. L. Bates	Mission	188.7	F
	E. S. Jospin	Point Comfort	234.9	F
Dallas Power & Light Co.	Dallas	Dallas	223.5	F
	Mountain Creek	Dallas	989.7	F
	Parksdale	Dallas	340.6	F
	North Lake	Dallas	708.6	F
	Lake Hubbard	Dallas	396.5	F
			526.0*	F
	Big Brown	Dallas	83.3	F
El Paso Electric Co.	Rio Grande	El Paso	235	F
	Newman	El Paso	265.8	F

EPA REGION VI

TEXAS (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Gulf State Util. Co.	Neches	Beaumont	452.3	F
	Sabine	Bridge City	952	F
			580*	F
	Lewis Creek	Willis	500	F
Houston Lighting & Power Company	Deepwater	Houston	334.125	F
	Gable Street	Houston	84.1	F
	Deepwater-Champion	Houston	334.9	F
	Hiram O. Clarke	Houston	210	F
			96	G
	Greens Bayou	Houston	375	F
	Cedar Bayou	Bayton	692	F
			823*	F
	Webster	Webster	614	F
			16.3	G
	Bertrom, Sam	Houston	826.3	F
			49	G
	T. H. Wharton	Houston	322.8	F
			16.3	G
	W. A. Parish	Richmond	1255.4	F
			16.3	G
	P. H. Robinson	Bacliff	1549.5	F
			16.3	G
Southwestern Electric Service Co.	Jacksonville	Alabama	11.0	F
Southwestern Public Service Co.	Plant "X"	Earth, Tex.	434.4	F
	Nichols	Amarillo, Tex.	474.8	F
	Denver City	Denver City,Tex.	87.5	F
	East Plant	Amarillo	71	F
	Riverview	Borger	69.5	F
	Jones	Lubbock	235.2	F
	Moore County	Sunray	68.2	F
	Tuco	Abernathy	40	F

TEXAS (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Texas Electric Service Company	Graham	Graham	634.8	F
	Eagle Mountain	Fort Worth	706.2	F
	Handley	Fort Worth	523.4	F
	North Main	Fort Worth	116.3	F
	Wichita Falls	Wichita Falls	25	F
	Permian Basin	Monahans	165	F
			535.5*	F
	Morgan Creek	Colorado City	845.8	F
	Big Brown	Fairfield	593	F
Texas Power & Light Co.	Collin	Frisco, Tex.	156.3	F
	Lake Creek	Waco, Tex.	315.6	F
	River Crest	Bogata	112.5	F
	Stryker Creek	Rusk, Tex.	703.5	F
	Trading House Creek	Waco, Tex.	588.2	F
			799.2*	F
	Trinidad	Trinidad, Tex.	413.3	F
	Valley	Savoy, Tex.	1175	F
	Waco	Waco, Tex.	13	F
	De Cordova		775*	F
West Texas Util. Co.	Abilene	Abilene, Tex.	26.3	F
	Concho	San Angelo	52.5	F
	Pauline	Quanah	44.5	F
	Oak Creek	Bronte	81.6	
	Paint Creek	Stamford	241.6	
	Rio Pecos	Girvin, Tex.	136.5	F
			5.0	G
	San Angelo	San Angelo	100.8	F
			32.6	G
Austin Electric Dept.	Seaholm Station	Austin	134	F
	Holly Street	Austin	416	F
	Decker Creek	Austin	300	F
Bryan Municipal Elect. System	Bryan	Bryan	128.7	F

EPA REGION VI

TEXAS (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Coleman Munic. Power & Light Dept.	Coleman	Coleman	9.2	F
Denton Munic. Util.	Denton	Denton	123.8	F
Garland Electric Dept.	C. E. Newman	Garland	96.5	F
	Ray Olinger	Garland	187	F
Greenville Munic. Light & Power Dept.	Greenville	Greenville	48.2	F
Lubbock Power & Light Dept.	Holly Ave.	Lubbock	130.5	F
			29.5	G
San Antonio Public Service Board	Leon Creek	San Antonio	263.6	F
	Mission Rd.	San Antonio	163.6	F
	W. B. Tuttle	San Antonio	493.9	F
	W. H. Brattnig	San Antonio	882	F
	Owsommers	San Antonio	430	F
	Pearsall	San Antonio	75	F
	Comal	San Antonio	60	F
Brownsville Public Utilities Board	Silas Ray	Brownsville	53.0	F
			15.0	G
Brazos Electric Power Coop., Inc.	Poage	Belton	23	F
	Worth Tex.	Weathorford	81.6	F
	Randle W. Miller	Palo Pinto	166	F
South Texas Electric Coop., Inc.	Sam Rayburn	Nursery	25	F
			23	G
Texas A & M University	Univ. Utilities	College Station	22.25	F
Lower Colorado River Authority	Comal	New Braunfels	60	F
	Sim Gideon	Bastrop	250	F
			315*	F
	Granite Shoals	Marble Falls	408*	F

EPA REGION VI

TEXAS (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Southwestern Electric Power Co.	Knox Lee	Longview	186	F
	Lone Star	Lone Star	50	F
			49	G
	Wilkes	Jefferson	869.5	F

OKLAHOMA

Utility	Plant	Location	Gen. Capacity MW	Type
Oklahoma Gas & Elect.Co.	Seminole Sta.	Konawa	567	F
			22	F
	Horse Shoe Lake	Harrah	916.2	F
			27.2	G
	Mustang	Okla. City	509.3	F
			80	G
	Arbuckle	Sulphur	73.5	F
	Belle Isle	Okla. City	55.0	F
			8.0	G
	Riverbank	Muskogee	195.9	F
	Osage	Ponca City	40	F
	Byng	Byng	14	F
Public Service Co. of Oklahoma	Southwestern	Washita	482.7	F
	Tulsa	Tulsa	482	F
	Weleetka	Weleetka	83	F
	Northeastern	Oolagah	642.5	F
	Lawton	Lawton	29.5	F
Kingfisher Munic. Light Dept.	Kingfisher	Kingfisher	2	F
Ponca City Munic. Water & Light Dept.	Ponca City	Ponca City	16.5	F
Stillwater Water & & Light Dept.	Boomer Lake	Stillwater	22.65	F

EPA REGION VI

OKLAHOMA (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Western Farmers Electric Coop.	Anadarko	Anadarko	83	F
	Mooreland	Mooreland	191	F
Grand River Dam	Chouteau	Chouteau	56.3	F

EPA REGION VII

Region: Iowa, Kansas, Missouri, Nebraska

Region Office: Kansas City, Missouri

IOWA

Utility	Plant	Location	Gen.Capacity MW	Type
Interstate Power Co.	M. L. Kapp	Clinton	237.2	F
	Dubuque	Dubuque	91.3	F
	Lansing	Lansing	64	F
	Mason City	Mason City	23.5	F
Iowa Electric Light & Power Co.	Sutherland	Marshaltown	156.6	F
	Boone	Boone	34.3	F
	Iowa Falls	Iowa Falls	12.8	F
	Cedar Rapids	Cedar Rapids	92.3	F
	Duane Arnold	Cedar Rapids	550*	N
Iowa, Illinois Gas & Electric Co.	Riverside	Beltendorf	237	F
			72	G
Iowa Power & Light Co.	Des Moines Pwr. Station #2	Des Moines	324.6	F
	Council Bluffs	Council Bluffs	103.6	F
Iowa Public Service Co.	Neal	Sioux City	147	F
			300*	F
	Maynard	Waterloo	107.4	F
	Big Sioux	Sioux City	41	F
	Kirk	Sioux City	17.5	F
	Hawkeye	Storm Lake	19	F
	I.P.S. Gen.Plt.	Caroll	10.75	F
	I.P.S. Gen.Plt.	Eagle Grove	7.5	F
	Charles City		4.5	F
			36.0	G
Iowa Southern Util. Co.	Burlington	Burlington	212	F
	Bridgeport	Eddyville	71	F

IOWA (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Ames Electric Utility	Ames Municipal	Ames	63.7	F
Atlantic Munic. Util.	Atlantic	Atlantic	14.75	F
Cedar Falls Munic. Util.	Streeter	Cedar Falls	31.3 22	F G
Denison Munic. Util.	Denison	Denison	4.5	F
Grundy Center Munic. Light & Power	Grundy Center	Grundy Center	1.25	F
Harlan Munic. Util.	Harlan	Harlan	6.4	F
Mt. Pleasant Util.	Mt. Pleasant Munic.	Mt. Pleasant	13.3	F
Muscatine Power & Water Dept.	Muscatine	Muscatine	108	F
Pella Munic. Power & Light Dept.	Pella	Pella	17.0	F
Sibley Munic. Util.	Sibley	Sibley	2.5	F
Spencer Munic. Util.	Spencer	Spencer	17.5 22.4	F G
Trear Munic. Util.	Trear	Trear	1	F
Webster City. Munic. Light & Power Dept.	Webster City	Webster City	15.4 20.6	F G
Central Iowa Power Coop.	Prairie Creek Summit Lake	Cedar Rapids	244.7 22.5	F F
Corn Belt Pwr. Coop.	Humbolt		43.8	F

EPA REGION VII

KANSAS

Utility	Plant	Location	Gen. Capacity MW	Type
Central Kansas Power Co.	Hays	Hays	17	F
	Ross Beach	Hill City	35	F
	Colby	Colby	12	F
Kansas Gas & Elec. Co.	Gordon Evans	Wichita	539.3	F
	Murray Gill	Wichita	348.3	F
	Neosho	Parsons	113.5	F
	Ripley	Wichita	87.3	F
	Wichita	Wichita	22.8	F
Kansas Pwr. & Light Co.	Tecumseh	Tecumseh	346.1	F
	Lawrence	Lawrence	613.4	F
	Hutchinson	Hutchinson	252.2	F
	Abilene	Abilene	33.8	F
Western Power Div.	Phillipsburg	Phillipsburg	3.0	F
Central Telephone & Utilities Corp.	Arthur Mullergren	Great Bend	133.5	F
Anthony Electric Dept.	Power Station	Anthony	5.25	F
Chanute Munic. Elec.Dept.	Chanute	Chanute	19	F
Clay Center Munic. Electric Dept.	Clay Center	Clay Center	12.5	F
Coffeyville Munic. Water & Light Dept.	Coffeyville	Coffeyville	40.25	F
Iola Electric Dept.	Municipal	Iola	15.5	F
Kansas City Board of Public Utilities	KAW	Kansas City	161.3	F
	Quindaro	Kansas City	331.6	F
			15	G
Larned Elec. Light Dept.	Larned	Larned	12.8	F

KANSAS (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Mepherson Board of of Public Utilities	Mepherson #1	Mepherson	25.5	F
	Mepherson #2	Mepherson	32	F
Ottawa Water & Light Dept.	Ottawa	Ottawa	7.25	F
			11.8	G
Pratt Munic. Elect.Dept.	Pratt	Pratt	23.8	F
Washington Munic. Light Plant	Washington	Washington	4.8	F
Winfield Munic. Elec.	Winfield	Winfield	18	F
			11.3	G
	Winfield	Winfield	26.5	F
Wheatland Elec. Coop.,Inc.	Garden City	Garden City	28.5	F
			15	G
Sunflower Elec. Coop.	Ross Beach	Ross Beach	25	F
Empire Dist. Elec. Co.	Riverton	Riverton	42.5	F 25 Hz
			112.5	F
			12.5	G

MISSOURI

Utility	Plant	Location	Gen. Capacity MW	Type
Empire Dist.Elec. Co.	Asbury		200	F
Kansas City Power & Light Co.	Motrose	Clinton	563.1	F
	Hawthorn	Kansas City	887	F
	Northeast	Kansas City	156	F
	Grand Avenue	Kansas City	116.8	F
			10	F 25 Hz

MISSOURI (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Missouri Power & Light Co.	Gen. Plant	Jefferson City	12.7	F
	Gen. Plant	Mexico	19	F
Missouri Public Service Inc.	Sibley	Sibley	518	F
	Ralph Green	Pleasant Hill	49.5	F
St. Joseph Light & Power Co.	St. Joseph Gen.Plt.	St. Joseph	42.5	F
	St. Joseph Gen.Plt.	St. Joseph	150.5	F
Union Electric Co.	Labadie	Labadie	1110	F
	Meramec	SE St. Louis Co.	923	F
	Ashley	St. Louis	70	F
	Mound	St. Louis	40	F
	Sioux	Near Portage Des Sioux	1099.6	F
Chillicothe Munic.Util.	Chillicothe	Wabash Tracks	15	F
Columbia Water & Light Dept.	Columbia	Columbia	90	F
Fulton Board of Public Works	Fulton Plt. #1	Fulton	11.5	F
	Fulton Plt. #2	Fulton	8.3	F
Hannibal Board of Public Works	Hannibal	Hannibal	34	F
Independence Power & Light Dept.	Blue Valley	Independence	115	F
	Dodgion Street	Independence	10	F
Macon Municipal Util.	Macon	Macon	4.5	F
Sikeston Board of Munic. Utilities	Coleman	Sikeston	6.25	F
Springfield City Util.	James River	Kissick	268	F
Northeast Missouri Elec. Power Corp.	Gen. Plant	South River Sta.	15	F

MISSOURI (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
N.W. Electric Pwr. Coop., Inc.	Generation Plt.	Missouri City	40	F
Arkansas-Missouri Power Co.	Jim Hill		33	F
ASEC	Thomas Hill		440*	F
Central Elec. Power Coop.	Chamois		59	F

NEBRASKA

Utility	Plant	Location	Gen. Capacity MW	Type
Alliance Munic. Elec. Dept.	Alliance	Alliance	16.5	F
Fairbury Light & Water Dept.	Fairbury	Fairbury	21.5	F
Fremont Dept. of Util.	Fremont	Fremont	70.0	F
Grand Island Elec.Dept.	C. W. Brudick	Grand Island	70.5 60*	F F
Hasting Utilities Dept.	Hasting	Hasting	54	F
Schuyler Dept. of Util.	Schuyler	Schuyler	9	F
Central Nebraska Public Power & Irrigation Dist.	Canady	Lexington	100	F
Nebraska Public Power District	Bluffs	Scottsbluff	42.4	F
	Gen. Plant	Ogallala	9	F
	Sheldon	Hallam	228.6	F
	Kramer	Bellevue	113	F
	K Street	Lincoln	31.1	F
	Cooper	Nr.Nebraska City	800*	N

NEBRASKA (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Omaha Public Pwr. Dist.	Jones Street	Omaha	173.5	F
	North Omaha	Omaha	644.7	F
	South Omaha	Omaha	20	F
	Ft. Calhoun	Omaha	455*	N

EPA REGION VIII

Region: Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming

Region Office: Denver, Colorado

COLORADO

Utility	Plant	Location	Gen. Capacity MW	Type
Public Service Co. of Colorado	Valmont	Valmont	281.8	F
	Zuni	Denver	115.3	F
	Alamosa	Alamosa	18.9	F
	Arapahoe	Denver	250.5	F
	Cameo	Cameo	75	F
	Cherokee	Denver	250.5	F
	Ft. St. Vrain	Plattsville	330*	N
	Comenche	Comenche	350	F
Central Telephone & Utilities Corp.	Pueblo	Pueblo	30	F
	Canon City	Canon City	43.8	F
	Rocky Ford	Rocky Ford	7.5	F
Western Colorado Power Co.	J. Bullock	Montrose	10	F
	Durango	Durange	5	F
	Oliver	Paonia	3	F
Colorado Springs Dept. of Public Utilities	G. Bridsall	Colorado Springs	62.5	F
	Martin Drake	Colorado Springs	150	F
Burlington Municipal Light & Power	Burlington	Burlington	7.5	F
Ft. Collins Light & Power	Ft. Collins	Ft. Collins	8.0	F
Lamar Utilities Board	Lamar	Lamar	34	F
Trinidad Municipal Power & Light	Trinidad	Trinidad	7.5	F

EPA REGION VIII

COLORADO (Continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Walsenburg Utilities	Welsenburg	Welsenburg	11.0	F
Colorado Utilities Elec. Assn. Inc.	Hayden	Hayden	163.2	F
	Nucla	Nucla	34.5	F
	McGregor	McGregor	5.3	F

MONTANA

Utility	Plant	Location	Gen. Capacity MW	Type
Montana-Dakota Utilities Co.	Lewis & Clark	Sidney	50	F
	Glendive	Glendive	7	F
	Miles City	Miles City	2	F
	Baker	Baker	1	F
Montana Light & Power	Libby	Troy	12.6	F
	Troy	Troy	3.5	F
Montana Power Co.	Frank Bird	Billings	69	F
	J.E. Corette	Billings	172.8	F

NORTH DAKOTA

Utility	Plant	Location	Gen. Capacity MW	Type
Montana-Dakota Utilities Co.	R. M. Heskett	Mandan	100.1	F
	Beulah	Beuhla	13.5	F
	Williston	Williston	2	F
Valley City Municipal Utility	Valley City	Valley City	5	F
Basin Electric Power Coop.	Leland Olds	Stanton	240	F

EPA REGION VIII

NORTH DAKOTA (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Central Power Elec. Coop.	Wm. J. Neal	Velva	38	F
Minnkota Power Coop., Inc.	F. P. Wood	Grand Forks	21.5	F
	Milton R. Young	Centre	234.5	F
United Power Assoc.	Stanton	Stanton	172	F

SOUTH DAKOTA

Utility	Plant	Location	Gen. Capacity MW	Type
Black Hills Power & Light	Kirk	Lead	31.5	F
	Ben French St.	Rapid City	22	F
Northern States Power Co.	Lawrence	Sioux Falls	48	F
	Path Finder	Sioux Falls	66	F
			72	N
	Sioux Falls	Sioux Falls	16	F
Northwestern Public Service Co.	Aberdeen	Aberdeen	12.5	F
	Mitchell	Mitchell	12.5	F
Rushmore Elec. Power Coop., Inc.	Kirk	Near Whitewood	15	F
			16.5	F

UTAH

Utility	Plant	Location	Gen. Capacity MW	Type
Utah Power & Light	Carbon	Castle Gate	188.6	F
	Gadsby	Salt Lake City	251.6	F
	Hale	Orem	59	F
	Jordan	Salt Lake City	25.0	F
Provo City Power	Provo	Provo	14	F
California-Pacific Utilities Co.	Cedar	Cedar City	7.5	F

EPA REGION VIII

WYOMING

Utility	Plant	Location	Gen. Capacity MW	Type
Montana-Dakota Utilities	Acme	Sheridan	12	F
Black Hills Power & Light	Neil Simpson	Wyodak	27.7	F
	Osage	Osage	34.5	F
Pacific Power & Light Co.	D. Johnaron	Glenrock	456.7	F
			330*	F
	Trona	Near Green River	15.6	F
Utah Power & Light Co.	Naughton	Kemmerer	707	F
Rushmore Elec. Power Coop., Inc.	Naughton	-	380.8	F
			200*	F
Sinclair Refining Co.	Sinclair	Sinclair	6.2	F

EPA REGION IX

Region: Arizona, California, Hawaii, Nevada

Region Office: San Francisco, California

ARIZONA

Utility	Plant	Location	Gen. Capacity MW	Type
Arizona Public Service Co.	Yuma Axis	Yuma	86.7	F
	Saguaro	Red Rock	250	F
	Ocotillo	Tempe	227.3	F
	Cholla Point	Joshep City	113.6	F
	Phoenix	Phoenix	116.0	F
Tucson Gas & Elec. Co.	DeMoss-Petrie	Tucson	104.5	F
	Irvington	Tucson	504.5	F
Arizona Elect. Power Coop., Inc.	Apache	Cochise	75	F
			11.3	G
Salt River Project Agricultural Impr. & Power District	Agua Fria	Glendale	390.5	F
	Crosscut	Tempe	30	F
	Kyrene	Tempe	108	F
	Navajo	Paige	2310	*F
Southern Calif. Edison	Yuma Axis	Yuma	75	F

CALIFORNIA

Utility	Plant	Location	Gen. Capacity MW	Type
Pacific Gas & Elec. Co.	Avon	Avon	40	F
	Contra Costa	Antioch	1253.6	F
	Humboldt Bay	Eureka	102.4	F
			60	N
	Hunters Point	San Francisco	391.4	F
	Kern	Bakersfield	152	F

CALIFORNIA (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Pacific Gas & Elec. Co. (cont.)	Martinez	Martinez	40	F
	Morro Bay	Morro Bay	1056.3	F
	Moss Landing	Salinas	2152.2	F
	Oleum	Oleum	80	F
	Pittsburg	Pittsburg,Cal.	1277.8	F
	Potrero	San Francisco	317.9	F
	Geysers	Geysers	190	F
	Diablo Canyon	Near Oceano	1134*	N
San Diego Gas & Elec.Co.	Station B	San Diego	93	F
	Silvergate	San Diego	247	F
	Encina	San Diego	330.8	F
			20	G
	South Bay	Chula Vista	738.0	F
			18.6	G
Southern California Edison Co.	Redondo Beach	Redondo Beach	1579.4	F
	Long Beach	Long Beach	180	F
	Etiwanda	Etiwanda	911	F
			138.1	G
	Alamitos	Long Beach	1982.4	F
			138.0	G
	El Segundo	El Segundo	996.5	F
	Huntington Beach	Hermosa Beach	870.4	F
			121	G
	Mandlay Steam	Oxnard	435.2	F
			121	G
	Ormond Beach	Ormond Beach	750	F
	Highgrove	Colton	169	F
	San Bernardino	Loma Linda	130.6	F
	Cool Water	Dagget	146.9	F
	San Onofre	San Clemente	450	N
Burbank Public Service Dept.	Mangolia	Burbank	70	F
			21	G
	Olive	Burbank	99	F

CALIFORNIA (continued)

Utility	Plant	Location	Gen. Capacity MW	Type
Glendale Public Service Dept.	Glendale	Glendale	163	F
Los Angeles Dept. of Water and Power	Harbor	Wilmington	355	F
	Valley	Sun Valley	512.5	F
	Scattergood	Playa Del Rey	312.5	F
	Haynes	Seal Beach	1606	F
Pasadena Water & Power Dept.	Broadway	Pasadena	171	F
	Glenram	Pasadena	65.3	F
Imperial Irrigation Dist.	El Centro Steam Pl.	El Centro	187.6	F
Sacramento Municipal Utility District	Rancho Seco	Rancho Seco	913*	N

HAWAII

Utility	Plant	Location	Gen. Capacity MW	Type
Hawaiian Electric Co.	Honolulu	Honolulu	168.2	F
	Waiau	Waiau	394.5	F
	Kahe	Kahe	239.0	F
	Hilo	Hilo	37.5	F
			11.7	G
	Maui	Maui	35	F
Kauai Electric Co.	Port Allen	Kauai	10	F
Maui Elec. Co., Ltd.	Kahului	Maui	38.5	F

EPA REGION IX

NEVADA

Utility	Plant	Location	Gen. Capacity MW	Type
Nevada Power Co.	Clark Station	East Las Vegas	190.3	F
	Sunrise Station	Las Vegas	81.6	F
	Reid Gardner St.	Moapa	227.3	F
Sierra-Pacific Power Co.	Tracy Steam Plt.	Sparks	135	F
			25	G
	Fort Churchill Steam Plant	Yerington	110	F
Southern California Edison Co.	Mohave	Near Big Bend	1210	F

EPA REGION X

Region: Alaska, Idaho, Oregon, Washington

Region Office: Portland, Oregon

ALASKA

Utility	Plant	Location	Gen. Capacity MW	Type
Fairbanks Municipal Utilities System	Fair Banks	Fairbanks	8.5	F
			7.0	G
Chugach Electric Association Inc.	Kink Arm	Anchorage	14.5	F
Golden Valley Electric Association Inc.	Fairbanks	Fairbanks	9.5	F
			17.5	G
	Healy	Healy	22	F
U. S. Air Force	Elmendorf West	Elmendorf	22.5	F
	Elmendorf Central	Elmendorf	9.0	F
	Fort Wainwright	Near Fairbanks	23.5	F
	Eielson	Eielson	10	F
	Clear AFB	Near Nenana	22.5	F
U. S. Army	Ft. Richardson	Anchorage	18.0	F
	Ft. Greely	Ft. Greely	2.0	N
	Port Whittier	Portage	6.5	F
U. S. Navy	Kodiak	Kodiak	4.0	F
	Adak	Adak	15.9	F

IDAHO

Utility	Plant	Location	Gen. Capacity MW	Type
Potlatch Forests Inc.	Lewinston	Lewinston	10	F

EPA REGION X

OREGON

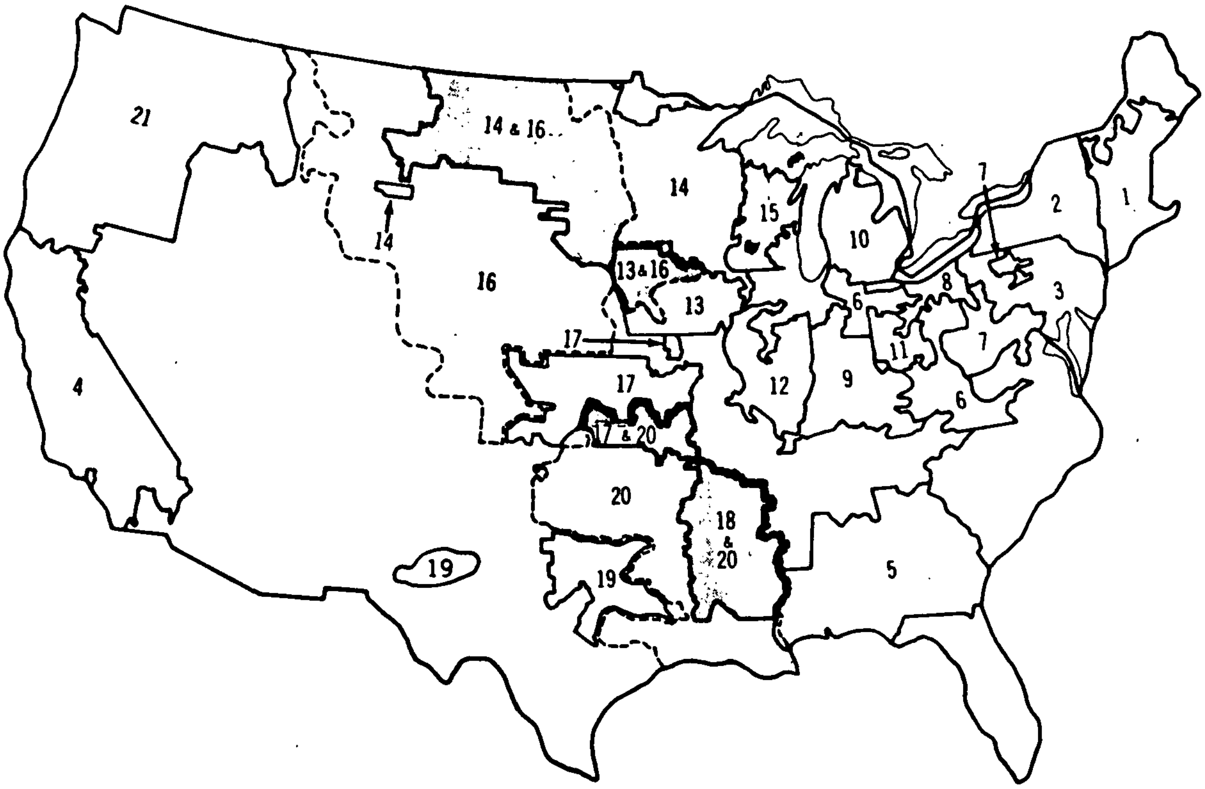
Utility	Plant	Location	Gen. Capacity MW	Type
Pacific Power & Light Co.	Lincoln	Portland	35	F
	North Bend	North Bend	15	F
	Astoria	Astoria	8	F
	Springfield	Springfield	5	F
Portland Gen. Elec. Co.	Station L	Portland	75.5	F
Eugene Water & Elec. Board	Eweb	Eugene	25	F

WASHINGTON

Utility	Plant	Location	Gen. Capacity MW	Type
Seattle Dept. of Light.	Lake Union	Seattle	30	F
	Georgetown	Seattle	22	F
Tacoma Public Utilities-Light Division	Steam Plant #1	Tacoma	9	F
	Steam Plant #2	Tacoma	50	F
Pacific Power & Light Co.	Centralia	Centralia	700	F
			700*	F
Public Utility Dist. No. 1 of Cowlitz County	Long View	Lewis River	26.7	F
Public Utility Dist. No. 1 of Pend Dreille Co.	Box Canyon	Lone	77.2	F
Puget Sound Power & Light	Shuffleton	Renton	87.5	F
Washington Public Power Supply System	Hanford	Hanford	860	N
			1135*	N

APPENDIX 2

FORMAL COORDINATING ORGANIZATIONS OR POWER POOLS 292



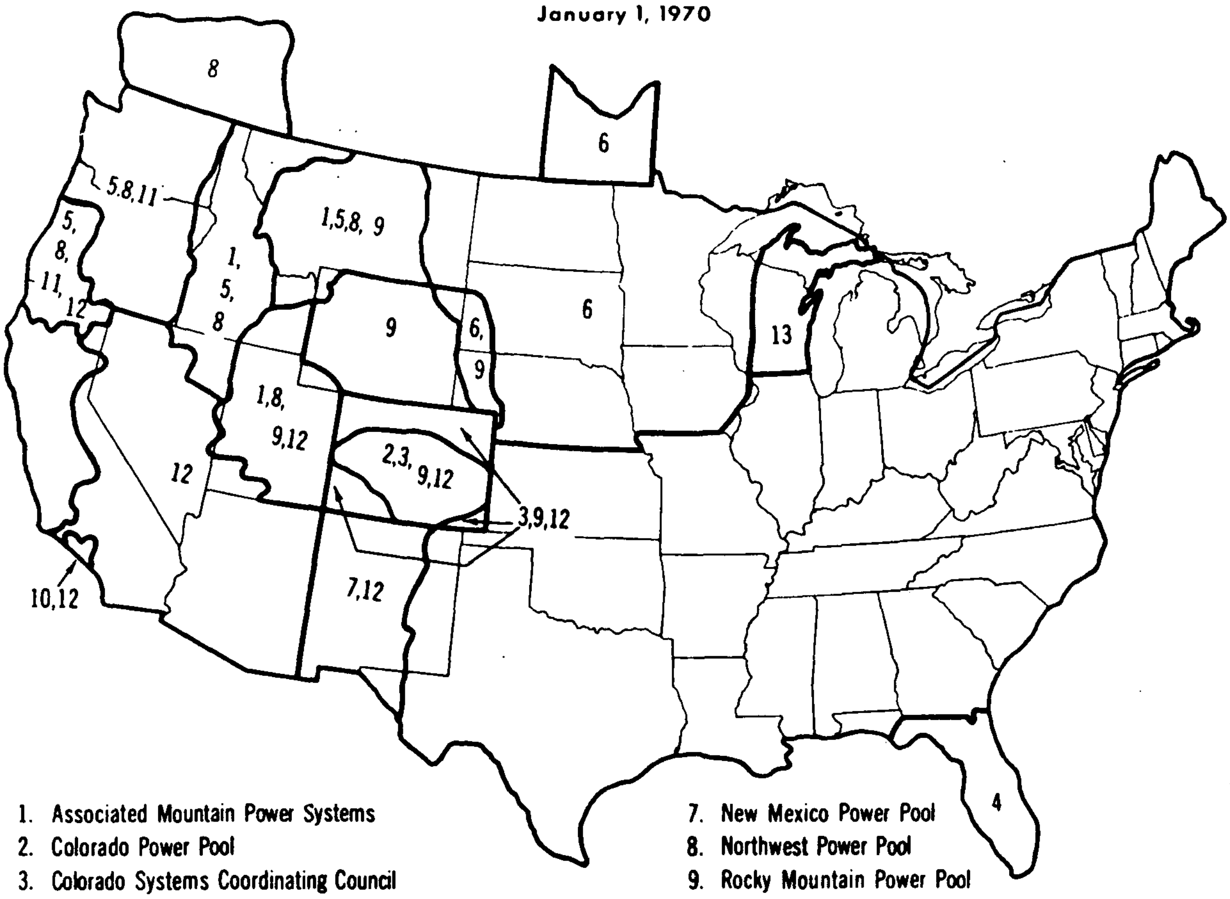
1. New England
2. New York
3. P-J-M Interconnection
4. California
5. The Southern Company System
6. American Electric Power System
7. Allegheny Power System
8. Central Area Power Coordination
9. Kentucky - Indiana
10. Michigan
11. Cincinnati, Columbus, Dayton
12. Illinois - Missouri
13. Iowa
14. Upper Mississippi Valley
15. Wisconsin
16. Missouri Basin Systems Group
17. Missouri - Kansas
18. Middle South Utilities System
19. Texas Utilities Company System
20. South Central Electric Companies
21. Pacific Northwest Coordination

NOTE: Not all systems operating in each of the 21 areas are formal power pool members.

Figure A-2-1

INFORMAL COORDINATING GROUPS

January 1, 1970



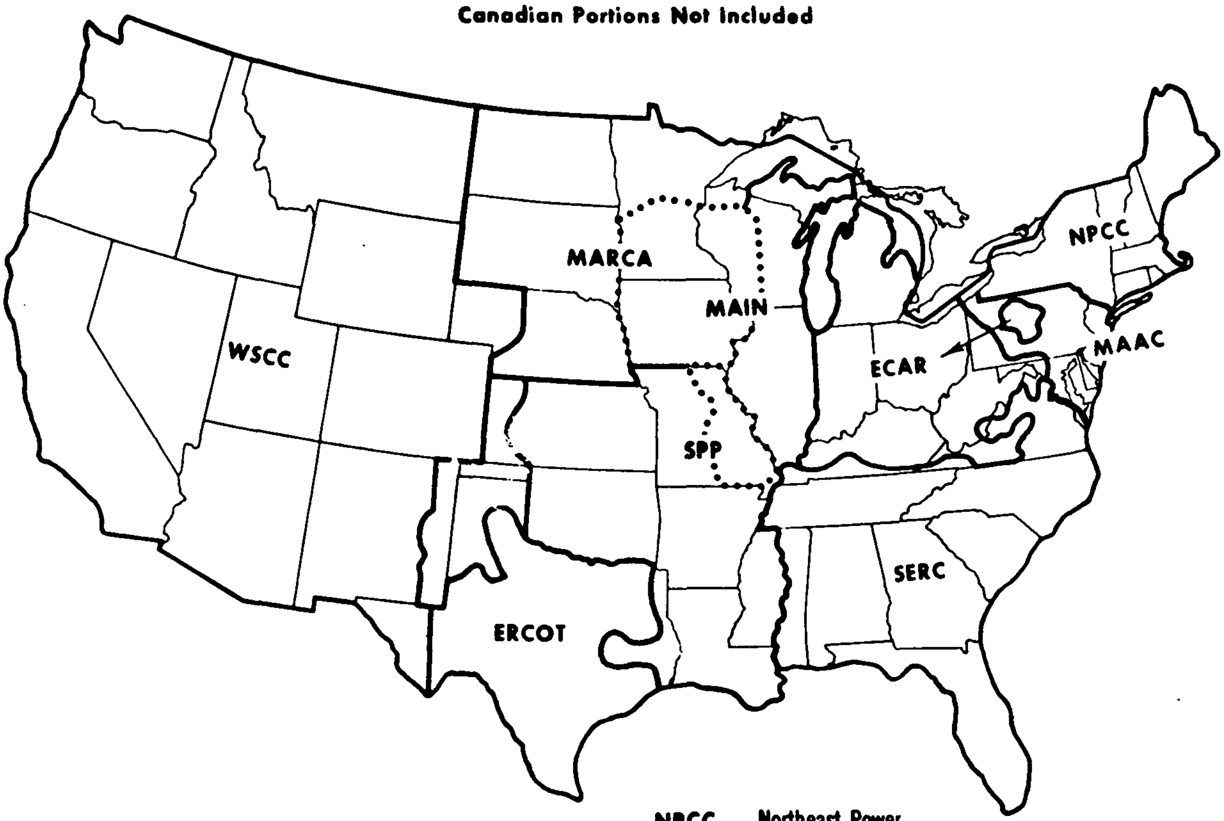
1. Associated Mountain Power Systems
2. Colorado Power Pool
3. Colorado Systems Coordinating Council
4. Florida Operating Committee
5. Joint Power Planning Council
6. Mid-Continent Area Power Planners
7. New Mexico Power Pool
8. Northwest Power Pool
9. Rocky Mountain Power Pool
10. Southern California Municipal Group
11. The Intercompany Pool
12. Western Energy Supply & Transmission Associates
13. Wisconsin Upper Michigan Systems

NOTE: Area boundaries are only general; not all systems within a boundary are members of the designated organizations

Figure A-2-2

NATIONAL ELECTRIC RELIABILITY COUNCIL REGIONS

Canadian Portions Not Included



WSCC	Western Systems Coordinating Council
MARCA	Mid-Continent Area Reliability Coordination Agreement
SPP	Southwest Power Pool
ERCOT	Electric Reliability Council Of Texas
MAIN	Mid-America Interpool Network
NPCC	Northeast Power Coordinating Council
MAAC	Mid-Atlantic Area Coordination Group
ECAR	East Central Area Reliability Coordination Agreement
SERC	Southeastern Electric Reliability Council

Figure A-2-3

Table A-2-1

Members of Formal Coordinating Organizations or Power Pools

(January 1, 1970)

New England Power Pool (NEPOOL)[1]

- Northeast Utilities[2]
- Boston Edison Company
- New England Electric System[2]
- Central Maine Power Co.
- The United Illuminating Co.
- Public Service Company of New Hampshire
- Eastern Utilities Associates[2]
- New England Gas & Electric Assoc.[2]
- Central Vermont Public Service Co.

New York Power Pool (NYPP)[3]

- Consolidated Edison Company of N. Y.
- Niagara Mohawk Power Corp.
- Long Island Lighting Company
- New York State Electric and Gas Corp.
- Central Hudson Gas & Electric Corp.
- Rochester Gas and Electric Corp.
- Orange and Rockland Utilities, Inc.
- Power Authority of the State of N. Y.

Pennsylvania-New Jersey-Maryland Interconnection (PJM)

- Public Service Electric and Gas Company
- Philadelphia Electric Company
- General Public Utilities Corporation
  - Metropolitan Edison Company
  - Pennsylvania Electric Company
  - Jersey Central Power and Light Company
  - New Jersey Power & Light Company
- Pennsylvania Power & Light Company
- Baltimore Gas and Electric Company
- Potomac Electric Power Company

Carolinas-Virginia Power Pool (CARVA)[4]

- Virginia Electric & Power Company
- Carolina Power & Light Company
- Duke Power Company
- South Carolina Electric & Gas Company

Southern Company System (Holding Co.)

- Alabama Power Company
- Georgia Power Company
- Gulf Power Company
- Mississippi Power Company

American Electric Power System (AEP) (*Holding Company*)

- Appalachian Power Company
- Indiana & Michigan Electric Co.
- Kentucky Power Company
- Kingsport Power Co.
- Michigan Power Co.
- Sewell Valley Utilities Co.
- Wheeling Electric Co.
- Ohio Power Company

Allegheny Power System (APS) (*Holding Company*)

- Monongahela Power Company
- Potomac Edison Company
- West Penn Power Company

Central Area Power Coordination Group (CAPCO)

- Cleveland Electric Illuminating Company
- Duquesne Light Company
- Ohio Edison System (Holding Company)
  - Ohio Edison Company
  - Pennsylvania Power Company
- Toledo Edison Company

Cincinnati, Columbus, Dayton Pool (CCD)

- Columbus & Southern Ohio Electric Co.
- Dayton Power & Light Co.
- Cincinnati Gas & Electric Co.

Kentucky-Indiana Power Pool (KIP)

- Indianapolis Power & Light Co.
- Public Service Co. of Indiana
- Kentucky Utilities Company

Michigan Pool

- Consumers Power Company
- Detroit Edison Company

Missouri-Kansas Pool (MOKAN)[5]

- Empire District Electric Company
- Kansas City Power & Light Company
- Kansas Gas & Electric Company
- Kansas Power and Light Company
- Missouri Public Service Company

Middle South Utilities System (Holding Co.)

- Arkansas Power and Light Company
- Louisiana Power and Light Company
- Mississippi Power & Light Company
- New Orleans Public Service, Inc.

South Central Electric Companies (SCEC)

- Gulf States Utilities Company
- Oklahoma Gas and Electric Company
- New Orleans Public Service Company
- Central Louisiana Electric Company
- Public Service Co. of Oklahoma
- Southwestern Electric Power Company
- Arkansas Power and Light Company
- Louisiana Power and Light Company
- Mississippi Power and Light Company
- Kansas Gas and Electric Company
- Empire District Electric Company

Texas Utilities System (Holding Company)

- Dallas Power & Light Company
- Texas Electric Service Company
- Texas Power and Light Company

Illinois-Missouri Pool

- Central Illinois Public Service Company
- Illinois Power Company
- Union Electric Company

Upper Mississippi Valley Power Pool

- Cooperatives
  - Cooperative Power Association
  - Dairyland Power Cooperative
  - Minnkota Power Cooperative
  - Northern Minnesota Power Assoc.
  - Rural Cooperative Power Assoc.
  - United Power Association
- Investor-owned Companies
  - Interstate Power Company
  - Lake Superior District Power Co.
  - Minnesota Power & Light Company
  - Montana-Dakota Utilities Co.
  - Northern States Power Company
  - Northwestern Public Service Company
  - Otter Tail Power Company

Iowa Pool

- Iowa Electric Light and Power Co.
- Iowa-Illinois Gas and Elec. Co.
- Iowa Power and Light Company
- Iowa Public Service Company
- Iowa Southern Utilities Company
- Corn Belt Power Cooperative

Wisconsin Power Pool

- Wisconsin Public Service Corporation
- Wisconsin Power and Light Company
- Madison Gas and Electric Company

Missouri Basin Systems Group (MBSG)

- U. S. Bureau of Reclamation
- Basin Electric Power Cooperative
- Central Power Electric Cooperative
- Nebraska Public Power System
- Other Members

California Power Pool

- Southern California Edison Company
- Pacific Gas and Electric Company
- San Diego Gas & Electric Company

Pacific Northwest Coordination Agreement

- Bonneville Power Administration
- City of Eugene, Oregon
- City of Seattle, Washington
- City of Tacoma, Washington
- Colockum Transmission Company
- Montana Power Company
- Pacific Power & Light Company
- Portland General Electric Company
- P. U. Dist. No. 1 of Chelan County, Washington
- P. U. Dist. No. 1 of Cowlitz County, Washington
- P. U. Dist. No. 1 of Douglas County, Washington
- P. U. Dist. No. 1 of Pend Oreille County, Washington
- P. U. Dist. No. 2 of Grant County, Washington
- Puget Sound Power & Light Company
- United States Corps of Engineers
- Washington Water Power Company

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[1] Data for the nine systems which initiated NEPOOL studies. As of January 1970, nearly all New England utilities were represented in the expanded negotiations which were in process since June 1969.

[2] Holding company.

[3] Power Authority of the State of New York takes part in pool planning and operations, but not in commercial transactions of the pool.

[4] Pooling agreement terminated as of October 20, 1970.

[5] There are also five satellite members: St. Joseph Light & Power Co.; Board of Public Utilities of Kansas City, Kansas; City of Independence, Missouri; Central Telephone and Utilities Corp.—Western Power Division; and Associated Electric Cooperative, Inc.

Table A-2-2

Informal Coordinating Organizations or Power Pools

[January 1, 1970]

PLANNING ORGANIZATIONS AND THEIR MEMBERS

Associated Mountain Power Systems (AMPS)

- Idaho Power Co.
- Montana Power Co.
- Pacific Power & Light Co.
- Utah Power & Light Co.
- Washington Water Power Co.

Total 5 Systems

Joint Power Planning Council (JPPC)

- Pacific Power & Light Company
- Portland General Electric Co.
- Puget Sound Power & Light Co.
- Washington Water Power Co.
- Bonneville Power Administration
- Publicly Owned Utilities in Oregon, Washington, Idaho and Montana (104 Systems)

Total 109 Systems

Mid-Continent Area Power Planners (MAPP)

- Black Hills Power & Light Co.
- Northwestern Wisconsin Electric Co.
- Omaha Public Power District
- Nebraska Public Power District
- Central Iowa Power Cooperative
- Eastern Iowa Light & Power Coop.
- Iowa Power Pool Members
  - Iowa Electric Light and Power Co.
  - Iowa-Illinois Gas and Electric Co.
  - Iowa Power and Light Co.
  - Iowa Public Service Co.
  - Iowa Southern Utilities Co.
  - Corn Belt Power Cooperative
- Union Electric Company
- Municipal Systems in Nebraska, South Dakota, Iowa and Minnesota (28 Systems)
- Manitoba Hydro-Electric Board
- Upper Mississippi Valley Power Pool
  - Cooperatives
    - Cooperative Power Association
    - Dairyland Power Cooperative
    - Minnkota Power Cooperative
    - Northern Minnesota Power Assoc.
    - Rural Cooperative Power Assoc.
  - Investor-owned Companies
    - Interstate Power Company
    - Lake Superior District Power Co.
    - Minnesota Power & Light Company
    - Montana-Dakota Utilities Company
    - Northern States Power Company
    - Northwestern Public Service Co.
    - Otter Tail Power Company

Total 54 Systems

Western Energy Supply & Transmission Associates (WEST)

- Arizona Public Service Co.
- Los Angeles Dept. of Water & Power
- El Paso Electric Co.
- Nevada Power Co.
- Public Service Company of Colorado
- San Diego Gas & Electric Co.
- Sierra Pacific Power Co.
- Southern California Edison Co.
- Tucson Gas & Electric Co.
- Utah Power & Light Co.
- Arizona Electric Power Coop.
- Public Service Co. of New Mexico
- Arizona Power Authority
- Burbank Public Service Dept.
- City of Colorado Springs
- Colorado-Ute Electric Association, Inc.
- Glendale Public Service Department
- Imperial Irrigation District
- Pacific Power & Light Co.
- Pasadena Municipal Light & Power Dept.
- Plains Electric G.&T. Coop., Inc.
- Salt River Project
- Central Telephone & Utilities Corp. (Southern Colo. Power Div.)

Total 23 Systems

OTHER INFORMAL COORDINATING GROUPS AND THEIR MEMBERS

Colorado Power Pool (COLOPP)

- Public Service Company of Colorado
- City of Colorado Springs
- Southern Colorado Power Div. of C.T.U.

Total 3 Systems

The Intercompany Pool (INTERPOOL)

- Pacific Power & Light Company
- Portland General Electric Co.
- Puget Sound Power & Light Co.
- Washington Water Power Co.

Total 4 Systems

Southern California Municipal Group (SCMG)

- Los Angeles Department of Water and Power
- Glendale Public Service Dept.
- Burbank Public Service Dept
- Pasadena Municipal Light & Power Dept.

Total 4 Systems

Colorado Systems Coordinating Council (CSCC)

- Central Municipal Light & Power System
- Colorado Springs Dept. of Public Utilities
- Town of Estes Park
- Fort Collins Light & Power Department
- City of Fort Morgan
- Glenwood Springs Municipal Elec. System
- Julesburg Power & Light Department
- La Junta Municipal Utilities
- Utilities Board of the City of Lamar
- Las Animas Municipal Light & Power System
- City of Longmont
- Loveland Electrical Department
- City of Trinidad
- Colorado-Ute Electric Assoc., Inc.
- Arkansas Valley G. & T., Inc.
- Tri State G. & T. Assoc., Inc.
- Home Light & Power Co.
- Public Service Company of Colorado
- Central Telephone & Utilities Corp. (Southern Colo. Power Div.)
- Western Colorado Power Co.
- USBR

Total 21 Systems

Florida Operating Committee

- Florida Power & Light Co.
- Florida Power Corp.
- Tampa Electric Co.
- City of Jacksonville
- Orlando Utilities Commission

Total 5 Systems

Wisconsin-Upper Michigan Systems (WUMS)

- Wisconsin-Michigan Power Co.
- Upper Peninsula Power Co.
- Wisconsin Power Pool (3 Systems)
- Wisconsin Electric Power Co.

Total 6 Systems

Rocky Mountain Power Pool (RMPP)

- Public Service Company of Colorado
- Pacific Power & Light Co.
- USBR Regions 4 and 7
- Montana Power Co.
- Consumers Public Power District
- Southern Colorado Power Division of C.T.U.
- City of Colorado Springs
- Utah Power & Light Company
- Black Hills Power & Light Co.
- Tri-State G. & T. Assoc., Inc.
- Colorado-Ute Elec. Association, Inc.
- Cheyenne Light, Fuel & Power Co.
- Western Colorado Power Co.

Total 13 Systems

New Mexico Power Pool (NMPP)

- Community Public Service Company
- El Paso Electric Company
- Plains Electric G. & T. Coop.
- Public Service Company of New Mexico
- USBR Rio Grande Project

Total 5 Systems

Northwest Power Pool (NWPP)

- Bonneville Power Administration
- Eugene Water & Electric Board
- Idaho Power Co.
- Montana Power Co.
- Pacific Power & Light Co.,
- Portland General Electric Co.
- Puget Sound Power & Light Co.
- P.U.D. No. 1 of Chelan County
- P.U.D. No. 1 of Douglas County
- P.U.D. No. 2 of Grant County
- Seattle Department of Lighting
- Tacoma Public Utilities (Lt. Div.)
- Utah Power & Light Co.
- Washington Water Power Co.
- British Columbia Hydro & Power Authority
- West Kootenay Power & Light Co.
- Corps of Engineers-North Pacific Div.
- USBR-BPA (Southern Idaho)

Total 18 Systems

Table A-2-3

Multiple Memberships in Informal Coordinating Organizations or Power Pools

System	NMPP	WEST	SCMG	CSCC	NWPP	RMPP	COLOPP	INTERPOOL	JPPC	AMPS	MAPP
El Paso Electric Co	X	X									
Public Service Co. of N.M	X	X									
Plains Electric G. & T. Coop	X	X									
City of Los Angeles		X	X								
City of Glendale		X	X								
City of Burbank		X	X								
City of Pasadena		X	X								
Pacific P. & L. Co. (Wyoming)		X				X					
Utah Power & Light Co		X			X	X				X	
Public Service Co. of Colorado		X		X		X	X				
City of Colorado Springs		X		X		X	X				
Central Telephone & Utilities Corp. (Southern Colorado Power Division)		X		X		X	X				
Colorado-Ute Electric Association		X		X		X					
Western Colorado Power Co				X		X					
Tri-State G. & T. Association				X		X					
Bureau of Reclamation	X			X		X					
Portland General Electric Co					X			X	X		
Puget Sound Power & Light Co					X			X	X		
Pacific Power & Light Co					X			X	X	X	
Washington Water Power Co					X			X	X	X	
Bonneville Power Administration					X				X		
Idaho Power Co					X					X	
Montana Power Co					X	X				X	
Nebraska Public Power District						X					X

Table A-2-4

292

Individual Members of Regional Reliability Councils[1]

Northeast Power Coordinating Council (NPCC)

Boston Edison Co.
Burlington Electric Light Dept.
Central Hudson Gas & Electric Corp.
Central Maine Power Co.
Central Vermont Public Service Corp.
Consolidated Edison of N. Y., Inc.
Eastern Utilities Associates
Green Mountain Power Corp.
Hydro-Electric Power Comm. of Ontario
Long Island Lighting Co.
New England Electric System
New England Gas & Electric Assoc.
New York State Electric & Gas Corp.
Niagara Mohawk Power Corp.
Northeast Utilities
Orange and Rockland Utilities, Inc.
Power Authority of the State of New York
Public Service Company of New Hampshire
Rochester Gas and Electric Corp.
The United Illuminating Company

Mid-Continent Area Reliability Coordination Agreement (MARCA)

Basin Electric Power Cooperative
Black Hills Power and Light Co.
Central Iowa Power Coop.
Cooperative Power Assoc.
Corn Belt Power Coop.
Dairyland Power Coop.
Eastern Iowa Light and Power Coop.
Interstate Power Co.
Iowa Electric Light & Power Co.
Iowa-Illinois Gas & Electric Co.
Iowa Power and Light Co.
Iowa Public Service Co.
Iowa Southern Utilities Co.

Associates: Union Electric Co.
Manitoba Hydro-Electric Board of Canada

Lake Superior District Power Co.
Minnesota Power & Light Co.
Minnkota Power Coop., Inc.
Montana-Dakota Utilities Co.
Nebraska Public Power District
Northern Minnesota Power Association
Northern States Power Co.
Northwestern Public Service Co.
Omaha Public Power District
Otter Tail Power Co.
Rural Coop. Power Association
U. S. Bureau of Reclamation

Southwest Power Pool Agreement (SPP)

Arkansas-Electric Coop. Corp.
Arkansas-Missouri Power Co.
Arkansas Power & Light Co.
Associated Electric Coop., Inc.
Board of Public Utilities, Kansas City, Kan.
Central Louisiana Electric Co., Inc. (The)
City Power & Light Dept., Independence, Mo.
City Utilities of Springfield, Missouri
Empire District Electric Co. (The)
Grand River Dam Authority
Gulf States Utilities Company
Kansas City Power & Light Co.
Kansas Gas and Electric Co.
Kansas Power & Light Co. (The)
Louisiana Power & · · Co.
Mississippi Power & Light Co.
Missouri Edison Co.[2]
Missouri Power & Light Co.[2]
Missouri Public Service Co.
Missouri Utilities Company
New Orleans Public Service, Inc.
Oklahoma Gas & Electric Co.
Public Service Co. of Oklahoma
St. Joseph Light & Power Co.
Southwestern Electric Power Co.
Southwestern Power Administration
Western Farmers Electric Coop.
Western Power Division—CT & U

Mid-Atlantic Area Coordination Agreement (MAAC)

Atlantic City Electric Co.
Baltimore Gas and Electric Co.
Delmarva Power & Light Co.
Jersey Central Power & Light Co.
Metropolitan Edison Co.
New Jersey Power & Light Co.
Pennsylvania Electric Co.
Pennsylvania Power & Light Co.
Philadelphia Electric Co.
Potomac Electric Power Co.
Public Service Electric and Gas Co.
UGI Corp.

Southeastern Electric Reliability Council (SERC)

Alabama Electric Cooperative
Alabama Power Company
Carolina Power & Light Co.
City of Tallahassee
Crisp County Power Commission
Duke Power Company
Florida Power Corporation
Florida Power & Light Co.
Georgia Power Co.
Gulf Power Co.
Jacksonville Electric Authority
Lakeland Dept. of Elec. & Water
Mississippi Power Co.
Nantahala Power & Light Co.
Orlando Utilities Commission
Savannah Electric & Power Co.
South Carolina Electric & Gas Co.
South Carolina Public Service Authority
Southeastern Power Administration
Tampa Electric Co.
Tapoco, Inc.
Tennessee Valley Authority
Virginia Electric & Power Co.
Yadkin, Inc.

East Central Area Reliability Coordination Agreement (ECAR)

Appalachian Power Co.
Cincinnati Gas & Electric Co.
Cleveland Electric Illuminating Co.
Columbus & Southern Ohio Electric Co.
Consumers Power Co.
Dayton Power & Light Company
Detroit Edison Company
Duquesne Light Company
East Kentucky Rural Electric Coop.
Indiana-Kentucky Electric Corp.
Indiana & Michigan Elect. Co.
Indianapolis Power & Light Co.
Kentucky Power Company
Kentucky Utilities Company
Louisville Gas & Electric Company
Monongahela Power Company
Northern Indiana Public Service Co.
Ohio Edison Company
Ohio Power Company
Ohio Valley Electric Corp.
Pennsylvania Power Company
Potomac Edison Company
Public Service Co. of Indiana
Southern Indiana Gas & Electric Co.
Toledo Edison Co.
West Penn Power Company

Mid-America Interconnected Network (MAIN)

Associated Electric Coop., Inc.[3]
Central Illinois Light Company
Central Illinois Public Service Co.
City Water Light & Power, Springfield, Ill.
Commonwealth Edison
Illinois Power Company
Interstate Power Company[4]
Iowa Electric Light & Power Company[4]
Iowa-Illinois Gas & Electric Co.[4]
Iowa Power & Light Company[4]
Iowa Public Service Co.[5]
Iowa Southern Utilities Co.[5]
Madison Gas and Electric Co.
Northern States Power Co.[4]
Union Electric Company
Upper Peninsula Power Co.
Wisconsin Electric Power Company
Wisconsin-Michigan Power Company
Wisconsin Power and Light Company
Wisconsin Public Service Corp.

Electric Reliability Council of Texas (ERCOT)

B-K Electric Coop., Inc.
Baird, City of
Bartlett Electric Coop., Inc.
Bluebonnet Elec. Coop., Inc.
Boerne Utilities
Bowie, City of
Brady Water & Light Works
Brazos Elec. Power Coop., Inc.
Brenham Municipal Utilities
Brownsville, City of
Bryan, City of
Cap Rock Elec. Coop., Inc.
Central Power & Light Company
City of Austin
City Public Service Board (San Antonio)
Coleman, City of
Comanche County Elec. Coop. Assoc.
Community Public Service Company
Crosbyton, City of
Cuero Electric Dept.
Dallas Power & Light Company
Deep East Texas Elec. Coop., Inc.
Denton Municipal Utilities
Denton County Elec. Coop., Inc.
DeWitt County Elec. Coop., Inc.
Fannin County Elec. Coop., Inc.
Farmers Electric Coop., Inc.
Fayette Electric Coop., Inc.
Garland, City of
Giddings, City of
Goldthwaite, City of
Gonzales Electric District System
Grayson-Collin Elec. Coop., Inc.
Greenville Municipal Utilities
Guadalupe Valley Elec. Coop., Inc.
Jackson Electric Coop., Inc.
Jasper-Newton Electric Coop., Inc.
Johnson County Electric Coop. Assn.

Kaufman County Electric Coop., Inc.
Kimble Electric Coop., Inc.
LaGrange, City of
Lamar County Electric Coop. Assn.
Limestone County Elec. Coop., Inc.
Livingston, City of
Lockhart Utilities
Lower Colorado River Authority
Luling Utilities
Magic Valley Electric Coop., Inc.
McCulloch Electric Coop., Inc.
McLennan County Electric Coop., Inc.
Medina Electric Coop., Inc.
Mid-South Electric Coop. Assn.
Midwest Electric Coop., Inc.
Navarro County Electric Coop., Inc.
New Braunfels Utilities
New Era Electric Coop., Inc.
Nueces Electric Coop., Inc.
Robertson Electric Coop., Inc.
Robstown, City of
Sam Houston Electric Coop., Inc.
San Bernard Electric Coop., Inc.
San Patricio Electric Coop., Inc.
Schulenburg, City of
Seguin, City of
Shiner, Light & Water Department
Southwestern Electric Service Co.
South Texas Elec. Coop., Inc.
Southwest Texas Elec. Coop., Inc.
Stamford Electric Coop., Inc.
Teague, City of
Hamilton County Elec. Coop. Assn.
Hearne Municipal Plant
Hemphill Electric Department
Hill County Electric Coop., Inc.
Houston Lighting & Power Company
Hunt-Collin Elec. Coop., Inc.
Texas Electric Service Co.
Texas Power & Light Co.
Tri-County Electric Coop., Inc.
Tulia Light & Power Plant
Weimar, City of
West Texas Utilities
Wise Electric Cooperative, Inc.

Western Systems Coordinating Council (WSCC)

Arizona Power Authority
Arizona Public Service Co.
Bonneville Power Administration
British Columbia Hydro & Power Authority
California Dept. of Water Resources
Central Telephone & Utilities (South Colorado Power Division)
Chelan County P.U.D. No. 1
City of Glendale, Public Service Dept.
City of Tacoma, Dept. Public Utilities
City of Seattle Dept. of Lighting
Cowlitz County P.U.D. No. 1
Colorado—Ute Electric Association, Inc.
Douglas County P.U.D. No. 1
El Paso Electric Company
Eugene Water & Electric Board
Grant County P.U.D. No. 2
Idaho Power Company
Los Angeles Department of Water & Power
Metropolitan Water Dist. of South Calif.
Montana Power Company
Nebraska Public Power District
Nevada Power Company
Pacific Gas & Electric Co.
Pacific Power & Light Company
Portland General Electric Co.
Public Service Company of Colorado
Public Service Company of New Mexico
Puget Sound Power & Light Co.
Sacramento Municipal Utility District
Salt River Project
San Diego Gas & Electric Co.
Sierra Pacific Power Company
Southern Calif. Edison Company
Tri-State G&T Association
Tucson Gas & Electric Company
U. S. Bureau of Reclamation
U. S. Corps of Engineers
Utah Power & Light Company
Washington Water Power Company
West Kootenay Power & Light Company

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[1] Membership reported by all electric reliability councils as of September 1, 1970, except for the Electric Reliability Council of Texas which is reported as of November 20, 1970.

[2] Also members of MAIN through their parent company, Union Electric Company.

[3] Also member of SPP.

[4] Also member of MARCA.

[5] Member of MARCA. Resigned membership in MAIN as of June 30, 1971

CONVERSION FACTORS

Multiply (English Units) by Obtain (Metric Units)

English Unit	Abbreviation	Conversion	Abbreviation	Metric Unit
acres	ac	0.405	ha	hectares
acre-feet	ac ft	1233.5	cu m	cubic meters
British Thermal Unit	Btu	0.252	kg cal	kilogram-calories
British Thermal Unit/pound	Btu/lb	0.555	kg cal/kkg	kilogram-calories/kilogram
cubic feet/minute	cfm	0.028	cu m/min	cubic meters/minute
cubic feet/second	cfs	1.7	cu m/min	cubic meters/minute
cubic feet	cu ft	0.028	cu m	cubic meters
cubic feet	cu ft	28.32	l	liters
cubic inches	cu in	16.39	cu cm	cubic centimeters
degree Fahrenheit	°F	0.555(a) (°F-32)	°C	degree Centigrade
feet	ft	0.3048	m	meters
gallon	gal	3.785	l	liters
gallon/minute	gpm	0.0631	l/sec	liters/second
horsepower	hp	0.7457	kw	kilowatts
inches	in	2.54	cm	centimeters
inches of mercury	0.03342	atm	atmospheres	
pounds	lb	0.454	kg	kilograms
million gallons/day	mgd	3,785	cu m/day	cubic meters/day
mile	mi	1.609	km	kilometer
pound/square inch (guage)	psig	(0.06805(a) psig +1)	atm	atmospheres (absolute)
square feet	sq ft	0.0929	sq m	square meters
square inches	sq in	6.452	sq cm	square centimeters
tons (short)	t	0.907	kkg	metric tons (1000 kilograms)
yard	y	0.9144	m	meters

(a) Actual conversion, not a multiplier