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ECONOMIC IMPLICATIONS OF OPEN VERSUS CLOSED CYCLE COOLING FOR NEW STEAM ELECTRIC POWER PLANTS: A NATIONAL AND REGIONAL SURVEY

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ABSTRACT

Current and anticipated thermal pollution regulations will prevent many new steam electric power plants from operating with once-through cooling. Alternative cooling systems acceptable from an environmental view fail to operate with the same efficiencies, in terms of resources consumed per Kwh of electricity produced, offered by once-through cooling systems. As a consequence there are clear conflicts between meeting environmental objectives and meeting minimum cost and minimum resource consumption objectives. This report examines, at both the regional and national level, the costs of satisfying environmental objectives through the existing thermal pollution regulations.

This study forecasts the costs of operating those megawatts of new generating capacity to be installed between the years 1975 and 2000 which will be required to install closed cycle cooling solely to comply with thermal regulations. A regionally disaggregated approach is used in the forecasts in order to preserve as much of the anticipated inter-regional variation in future capacity growth rates and economic trends as possible. The net costs of closed cycle cooling over once-through cooling are based on comparisons of the costs of owning and operating optimal closed and open-cycle cooling configurations in separate regions, using computer codes to simulate joint power plant/cooling system operation. The expected future costs of current thermal pollution regulations are determined for the mutually exclusive - collectively exhaustive eighteen Water Resources Council Regions within the contiguous U.S., and are expressed in terms of additional dollar expenditures, water losses and energy consumption. These costs are then compared with the expected resource commitments associated with the normal operation of the steam electric power industry. It is found that while energy losses appear to be small, the dollar costs could threaten the profitability of those utility systems which have historically used once-through cooling extensively throughout their system. In addition the additional water demands of closed cycle cooling are likely to disrupt the water supplies in those coastal areas having few untapped freshwater supplies available.

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"Computer Optimization of the MIT Advanced Wet/Dry Cooling Tower Concept for Power Plants," by Choi, M., and Glicksman, L.R., MIT Energy Laboratory Report No. MIT-EL 79-035, September 1979.

"Operational Issues Involving Use of Supplementary Cooling Towers to Meet Stream Temperature Standards with Application to the Browns Ferry Nuclear Plant," by Stolzenbach, K.D., Freudberg, S.A., Ostrowski, P., and Rhodes, J.A., MIT Energy Laboratory Report No. MIT-EL 79-036, January 1979.

"An Environmental and Economic Comparison of Cooling System Designs for Steam-Electric Power Plants," by Najjar, K.F., Shaw, J.J., Adams, E.E., Jirka, G.H., and Harleman, D.R.F., MIT Energy Laboratory Report No. MIT-EL 79-037, January 1979.

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"Mathematical Predictive Models for Cooling Ponds and Lakes," Part B: User's Manual and Applications of MITEMP by Octavio, K.H., Watanabe, M., Adams, E.E., Jirka, G.H., Helfrich, K.R., and Harleman, D.R.F.; and Part C: A Transient Analytical Model for Shallow Cooling Ponds, by Adams, E.E., and Koussis, A., MIT Energy Laboratory Report No. MIT-EL 79-039, December 1979.

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Table of Contents

	Page
Title Page	i
Abstract	ii
Acknowledgements	iii
Table of Contents	v
List of Figures	vii
List of Tables	viii
Chapter I Introduction	1
1.1 Background	1
1.2 Current Thermal Pollution Regulations for New Plants	2
1.3 Development of Once-Through Cooling Under Existing Regulations	4
1.4 Objectives of this Study	5
1.5 Outline of Presentation	5
Chapter II Estimates of the Number of New Power Plants and the Cooling Systems they will Employ to the Year 2000	7
2.1 Introduction	7
2.2 Energy Demand Scenarios	8
2.3 New Once-Through Cooling Development	13
Alternative Pattern 1	19
Alternative Pattern 2	21
Alternative Pattern 3	22
Alternative Pattern 4	23
Chapter III Comparisons of Cost and Resource Consumption between Open and Closed Cycle Cooling Systems: Individual Plant Level	32
3.1 Introduction	32
3.2 Simulation Algorithm	33
3.3 Site Selection by Region	42
3.4 Economic Parameters	43
3.5 Simulation Results	50

		Page
Chapter IV	Comparison of Cost and Resource Consumption between Open and Closed Cycle Cooling Systems: Regional and National Level	68
4.1	Introduction	68
4.2	Comparison of Cost and Resource Consumption	69
4.3	Discussion of Total Costs	76
	Dollar Costs	76
	Fuel Consumption	78
	Water Consumption	79
Chapter V	Summary and Conclusions	84
5.1	Introduction	84
5.2	Fuel Consumption as a Consequence of Controls	84
5.3	Dollar Costs of Controls	85
5.4	Water Consumption as a Consequence of Controls	86
5.5	Concluding Remarks	87
References		92
Appendix A	Discussion of Alternative Siting Patterns	95
Appendix B	Discussion of Economic Parameters	109

List of Figures

Figure		Page
2.1	Water Resources Council Regions for the Contiguous U.S.	11
2.2	Location of Rivers in the United States where Once-Through Cooling could be Installed for a 1000 MW Fossil Steam Electric Plant in the Absence of Thermal Standards	14
2.3	Expected Distribution of New Capacity by Cooling Water Source and by Cooling System under Existing Thermal Regulations by the Year 2000 for the Contiguous U.S.	16
3.1	Evaporation from Representative Wet Towers as a Function of Wet-Bulb Temperature (TWB) and Dry-Bulb Temperature (TDB)	41
5.1	Distribution of Potential Once-Through Cooling Development by Water Body Size over Currently Projected Development	90
A.1	Cooling Systems in use Before 1973 as a Function of the Design Condenser Flow vs. the Average River Flow Past the Plant	99
A.2	Cooling Systems in use Before 1973 as a Function of the Design Plant Capacity vs. the Average River Flow Past the Plant	100
B.1	Regional Plant Cost Escalation Rates Over Time	114

List of Tables

Table		Page
2.1	Representative Energy and Electricity Demand Scenarios found in the Literature	9
2.2	Percentages of New Capacity Expected to be Installed Between 1975 and 2000 that could use Once-Through Cooling (High Energy Demand Scenario)	17
2.3	Percentages of New Capacity Expected to be Installed Between 1975 and 2000 that could use Once-Through Cooling (Low Energy Demand Scenario)	18
2.4	NERA Survey Results Indicating Cooling System Use for New Proposed Generating Capacity to be Installed Between 1977-1990	25
2.5	Comparison Between NERA's Estimates of the Percentage of New Capacity that will Install Closed Cycle Cooling for Environmental Reasons and this Study's Estimates of the same	28
2.6	Estimated Megawatts of New Capacity Requiring Closed Cycle Cooling for Purposes of Meeting Environmental Standards under the High Energy Demand Scenario	30
2.7	Estimated Megawatts of New Capacity Requiring Closed Cycle Cooling for Purposes of Meeting Environmental Standards under the Low Energy Demand Scenario	31
3.1	Projected Real Dollar Price Escalation Rates for Select Resources	46
3.2	Real Dollar Price Escalation Rates used in this Study	47
3.3	Projected 1980 Component Costs ($1977); High Price Escalation Scenario	48
3.4	Projected 1980 Component Costs ($1977); Low Price Escalation Scenario	49
3.5	Incremental Annual Operating Cost of Closed Cycle Cooling; High Price Escalation Scenario	52
3.6	Incremental Annual Operating Cost of Closed Cycle Cooling; Low Price Escalation Scenario	58
3.7	Incremental Present Valued Cost of Closed Cycle Cooling; High Price Escalation Scenario	64

Table		Page
3.8	Incremental Present Valued Cost of Closed Cycle Cooling; Low Price Escalation Scenario	65
3.9	Relative Incremental Annual Resource Costs Associated with Closed Cycle Cooling for Fossil Plants	66
3.10	Relative Incremental Annual Resource Costs Associated with Closed Cycle Cooling for Nuclear Plants	67
4.1	Expected Annual Cost of Current Thermal Regulations by Region (High Energy Demand)	70
4.2	Expected Annual Cost of Current Thermal Regulations by Region (Low Energy Demand)	71
4.3	Incremental Fuel Consumption in the Year 2000 Due to Thermal Controls	73
4.4	Incremental Freshwater Consumption in the Year 2000 without the Installation of Salt-Water Towers at Coastal Sites	74
4.5	Incremental Freshwater Consumption in the Year 2000 with the Installation of Salt-Water Towers at Coastal Sites	75
4.6	Impact of Thermal Control Induced Freshwater Demands in Relation to Regional Freshwater Demands (High Energy Demand Scenario)	81
4.7	Comparison of Thermal Control Induced Freshwater Requirements with New Freshwater Imports Authorized for the Period 1975 - 2000	83
5.1	Distribution of Potential Once-Through Cooling Development by Water Body Size Over Currently Projected Development	91

I INTRODUCTION

1.1 Background

At present in the U.S. efforts are being made to control domestic energy consumption and protect the environment. The concomitant pursuit of these two objectives are in obvious conflict in those sectors where environmental controls require additional energy use. One such sector is the Steam Electric Power Industry. Concerned that waste heat will have deleterious effects on aquatic environments, state and federal agencies have promulgated regulations that limit the discharge of waste heat to natural water bodies. For many new plants, these regulations require electric utilities to modify plant operating practices or adopt closed cycle cooling in place of open-cycle cooling. Neither of these two remedies allows a plant to operate with the same net thermodynamic efficiency offered by open-cycle cooling. Consequently, plants operating with thermal controls incur higher fuel costs than do plants operating without similar controls. In addition, closed cycle systems have higher capital costs and generally consume greater amounts of water (through evaporation) than do comparable open-cycle systems. Therefore, it must be recognized that implicit in any policy limiting once-through cooling there will be tradeoffs among cost, environmental impacts and resource consumption.

A fair amount of literature has been prepared asserting that the total costs of thermal controls (retrofitting existing plants and outfitting new plants) will have significant effects on the electric industry's ability to finance its operations, including capitalization for new plant and equipment (UWAG, 1974, 1977; Teknekron, 1976). Concern for these effects was a major consideration in the decision by a U.S. Court of Appeals remanding the EPA's thermal regulations and instructing that agency to consider the relationship between environmental protection and the costs of retrofitting closed cycle cooling systems at existing plants. Much of the current debate over thermal regulations surrounds the question of backfitting existing plants with the issue of outfitting new plants receiving less attention. There is a rationale for this disparity in emphasis: backfitting is more expensive than outfitting (due to the inflexibilities of working with an existing plant designed for open cycle cooling) and poses the most immediate costs. Nevertheless, we feel that the emphasis of the current debate has left the issue of outfitting without benefit of proper analysis. We, therefore, chose to examine the costs and resource commitments, at both a regional and national level, of outfitting new power plants to meet current thermal pollution regulations.

1.2 Current Thermal Pollution Regulations for New Plants

Public Law 92-500 (The Federal Water Pollution Control Act Amendments of 1972) instructs the Environmental Protection Agency to develop and promulgate effluent limitations for new steam electric power plants which will assure protection and propagation of indigenous aquatic ecosystems (§301(b)(2); §302(a); §306(b)(1)). At the same time, section 316(a) of this law provides for alternative thermal effluent standards for an individual plant when it can be demonstrated that the thermal discharge from such plant will assure protection and propagation of the indigenous aquatic ecosystem at that plant site.[1]

The EPA's effluent limitations for new plants (40 CFR 423, 1974) call for no discharge of heat from the main condensers into natural bodies of water, with the exception of heat released with the circulating water blowdown, thereby prohibiting once-through cooling for new plants. However, a particular plant may be exempt from this general effluent limitation and be allowed to install once-through cooling under the section 316(a) provision if it can be demonstrated that the thermal effluent from the once-through system will not harm the indigenous aquatic community (40 CFD 122, 1974). This demonstration must be presented either before the appropriate state or interstate agency if the agency has a discharge permit program approved by the EPA, or before the EPA if the state within which the discharge will occur has not received EPA approval for a discharge permit program. The EPA's water quality criteria for determining whether the protection objectives have been satisfied are based on a consideration of incremental temperature rises

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[1] In addition to the §316(a) provision for effluent standards, PL 92-500 contains a section, §316b, mandating that the design, construction and capacity of cooling water intake structures shall minimize undesirable, environmental impacts, primarily the impingement of organisms on the intake structure or the entrainment of these organisms into the condenser cooling system. While intake considerations alone may determine the acceptability of once-through cooling in particular locations, it is generally felt that the severity of intake impacts (eg. measured by the size of the intake's zone of influence relative to the size of the receiving waterbody) is correlated with the severity of the discharge impact (eg. measured by the size of the mixing zone or the overall temperature rise). At any rate the ability of a once-through cooling system to meet thermal standards will be used herein as the basis of acceptability for once-through cooling.

above the ambient temperature and the amount of time important species are expected to be exposed to these increases (EPA, 1976).

State water quality criteria for determining whether the protection objectives have been satisfied are incorporated into water quality standards which generally specify both the allowable temperature rise and the maximum allowable temperature within a body of water. For streams and rivers, the thermal standards are generally defined for a critical low flow (eg. 7-day, ten-year low flow). In addition most states set separate standards for streams or sections of streams which support cold water fisheries and for streams or sections of streams which support warm water fisheries.

1.3 Development of Once-Through Cooling Under Existing Regulations

Given the current state and federal water quality standards and criteria, the effluent limitation exemption provision under §316(a) allows new once-through cooling development, but at a much lower level than has been observed historically. Peterson, et al.(1973) estimates that even if plants located on streams were spaced to maximize the amount of once-through cooling possible within existing thermal standards, the share of steam electric capacity installed with once-through cooling on rivers would drop from 38% in 1970 to roughly 15% in 1990. The Federal Energy Regulatory Commission (1977) estimates the share of steam electric capacity installed with once-through cooling on <u>all</u> water bodies (lakes, rivers and oceans) will drop from 65% in 1975 to 23% in the year 2000. The U.S. Water Resources Council (1977) estimates that the share of steam electric capacity installed with once-through cooling on all bodies will drop to 16% in the year 2000. In addition, the U.S. Water Resources Council anticipates the overwhelming share of new capacity installed with once-through cooling between 1975 and 2000 will be located on the oceans with an absolute decline in the number of megawatts installed with freshwater once-through cooling systems. Thus, as a consequence of thermal pollution regulations, it is expected that the share of both new and total steam electric capacity installed with once-through cooling will fall below pre-1972 shares, with further once-through cooling development occurring primarily at coastal sites.

1.4 Objectives of this Study

In this study we assess the regional and national costs that may result as a consequence of restrictions on new once-through cooling development. In keeping with the intent of Congress that all costs of thermal control be identified (§302(b)(1), §304(b)(1)(B), §306(b)(1)(B)) we evaluate costs in terms of dollars spent and additional water and energy consumed in order to comply with water quality regulations.

1.5 Outline of Presentation

Chapter II presents our estimates of the new steam electric generating capacity to be installed between 1975 and 2000 which will be required to install closed cycle cooling in order to comply with water quality regulation. We assess the shares of new capacity that could be installed with once-through cooling both under current water quality regulations and with relaxed thermal regulations. Chapter III presents our assessment of the incremental costs of closed cycle cooling over once-through cooling for representative fossil and nuclear plants. Using power plant operating simulation models originally developed by Crowley, et al.,(1975) and modified at M.I.T. (Najjar, et al., 1978) we make separate cost estimates for various regions in the contiguous United States. In Chapter IV we combine our estimates of the new steam electric capacity which will be required by law to install closed cycle cooling with our assessment of the incremental costs of closed cycle cooling for representative plants. The result is our assessment, in terms of dollars spent and additional water and energy consumed, of the costs of complying with current thermal regulations. We represent these costs in terms of the annual costs between 1975 and 2000 of having new plants comply with existing standards of performance.

II ESTIMATES OF THE NUMBER OF NEW POWER PLANTS AND THE COOLING SYSTEMS THEY WILL EMPLOY TO THE YEAR 2000

2.1 Introduction

The objective of this chapter is to estimate the number of new plants (or alternatively the amount of new electric generating capacity) to be built between the years 1975 and 2000 that will be required to install closed cycle cooling systems in order to comply with current thermal pollution regulations. That is, of the new plants that will be built between 1975 and the year 2000 a small percentage will be able to install once-through cooling under the current thermal regulations while a larger percentage of these new plants would be able to install once-through cooling were these regulations relaxed or removed altogether. Therefore, the difference between the number of new plants that could install once through cooling without thermal controls and the number of new plants that will install once-through cooling under the existing regulations represents the net number of new electric generating stations that will be required to install closed cycle cooling to comply with current thermal pollution regulations.

Our estimates of the net electric generating capacity affected by current thermal regulations are made in two steps. In section 2.2 we estimate the total number of megawatts of new generating capacity that could be installed between the years 1975-2000. These estimates are made for separate regions covering the contiguous United States and are developed from energy demand projections found in the literature. In section 2.3 we investigate a number of potential new facility siting patterns that incorporate water availability considerations to indicate where new generating stations could be located, in every region, for the purposes of making greater use of once-through cooling were the current thermal controls relaxed or removed. Because water availability is a determining factor for whether once-through cooling can be installed at any site, each facility siting pattern represents a separate estimate of the potential for being able to use once-through cooling at new power plants were thermal controls not binding.

The analyses performed in sections 2.2 and 2.3 are carried out by Water Resource Council Region and aggregated to the national level. (Figure 2.1 indicates the location of the 18 WRC Regions withing the contiguous United States.) Our national estimates for the net percentage of new plants that will install closed cycle cooling to comply with thermal regulations are then compared to similar estimates prepared for the Utility Water Act Group (UWAG) by National Economic Research Associates.

2.2 Energy Demand Scenarios

The scenarios projecting future electric capacity additions used in this study come from the published literature. Since 1972 at least thirteen different government agencies, industry groups and universities have published eighteen separate studies which, in all, provide forty-seven energy demand scenarios for the United States. Of these 47 forecasts, 20 offer projections to the year 2000, and are summarized in Table 2.1.

In these estimates the anticipated new capacity is generally computed from an electric energy demand forecast, in MWH, which can be forecast separately or can in turn be calculated from a total energy demand forecast and an electrification forecast. The initial step in

Table 2.1 Representative Energy and Electricity Demand Scenarios found in the Literature

Source	Publication Date	Total Energy 10^{15} BTU/Year		Electricity 10^{12} KWH/Year		Electricity* Share(%)		Peak Load** 10^3 MW		Capacity*** 10^3 MW	
		1985	2000	1985	2000	1985	2000	1985	2000	1985	2000
CTM High	11/72				9.890				1851		2221
CTM Medium	11/72				3.450				646		745
CTM Low	11/72				2.010				376		451
Dupree-West	12/72	116.6	191.9	4.140	9.010	36.4	48.1	775	1686	930	2023
B.O.M.-Central C	1973			4.378	10.432			819	1952	983	2343
HUD.-Jorgenson	9/74	108.2	164.5	3.363	6.981	31.8	43.4	629	1306	755	1568
ERDA-48 Scenario 0	6/75	107.3	165.5	3.455	6.903	33.0	42.7	647	1292	776	1550
ERDA-48 Scenario I	6/75	96.9	122.5	3.199	4.152	33.8	34.7	599	777	718	932
ERDA-48 Scenario II	6/75	107.3	165.4	3.455	6.792	33.0	42.0	647	1271	776	1525
ERDA-48 Scenario III	6/75	106.7	161.2	3.747	8.236	36.0	52.3	701	1541	841	1850
ERDA-48 Scenario IV	6/75	107.1	158.0	3.334	4.694	31.9	30.4	624	878	749	1054
ERDA-48 Scenario V	6/75	98.1	137.0	3.217	4.335	33.6	32.4	602	811	722	974
ERDA Imp. Dep.	6/76	100.0	156.2	3.321	5.860	34.0	38.4	621	1097	746	1316
ERDA Dom. Dev.	6/76	96.7	135.9	3.321	6.348	35.2	47.8	621	1188	746	1426
FERC-Mod. C.C.	4/77	103.5	163.4	4.070	9.332	40.3	58.5	762	1746	914	2096
EPRI-Ref.En.Sys.	6/77	100.9	142.4	2.880	5.030	29.2	36.2	539	941	647	1130
ERDA W/Carter	9/77			3.050	5.315			571	995	685	1194
EPRI-Demand'77 High	3/78	104.8	196.0	3.889	9.200	38.0	48.1	728	1722	873	2066
EPRI-Demand'77 Base	3/78	97.6	159.0	3.655	7.400	38.3	47.7	684	1385	821	1662
EPRI-Demand'77 Cons.	3/78	94.4	146.0	3.544	6.600	38.4	46.3	663	1235	796	1482

*Assuming Heat Rate = 10,238.4 BTU/KWH, Refers to Electricity's Share of Total U.S. Energy Consumption
**Assuming System Load Factor = .61
***Assuming Margin = 20% of Peak Load

estimating the installed capacity requirements for any year is to forecast the point peak load demand (e.g. highest 24 hr. continuous demand in MW) expected in that year. This is defined, Meier (1976), as:

$$MW^{t}_{p} = \frac{E_A^{\ t}}{SLF^{t}_{A} \cdot 8760}$$

where:

MW^t_p = expected peak demand in year t (MW)

E^t_A = expected electricity generation in year t (MWH)

SLF^t_A = expected system load factor in year t

8760 = number of hours per year

The SLF^t_A is the ratio of a system's average annual power output and its actual maximum power output, and is commonly in the range of .55 to .65.

While MW^t_p represents the maximum power demand expected on the system in year t_1 the actual amount of capacity installed by that year must exceed this in order that there are sufficient reserves in the event planned and unplanned outages prevent some plants from operating during the period of peak demand. A commonly used standard of relability is that the available system capacity at any time (installed capacity minus capacity not currently operable) will exceed demand in all but one day every ten years. Currently the norm is that a reserve margin equal to 20%-30% of the peak demand will be adequate to meet all but the one day in ten year event (Meier, 1976).

Referring to Table 2.1, we see an incredible range in the projections found in the literature: The lowest forecast for new electric

Figure 2.1 Water Resources Council Regions for the Contiguous U.S.

generating capacity installed by the year 2000 is one-fifth the highest estimate. Even for projections published after 1976 the range in predictions remains large, with the highest projection almost twice that of the lowest. Most of this observed variation between projections is due to differences in key assumptions made for each projection. For example, differences in the assumed growth rates for energy demand in general and in electrification in particular, in assumptions regarding the share of the nation's electricity that will come from steam electric plants, and in assumptions regarding policies for reducing peak demand (e.g. peak load pricing) can all be small individually, but when combined and compounded over a twenty-five year period contribute to a remarkable variation in the final results.

Because many of the parameters used in these forecasts are sensitive to changes in government policies and in the economic environment, both of which are uncertain, it is hard to say which projections are most reasonable, or to identify a single "most probable" forecast describing new capacity growth. Therefore we chose a high energy demand case, using the FERC projections, and a low energy demand, using the ERDA Accelerated Domestic Development forecasts. These two projection cover a reasonable range of the forecasts published so far.

The FERC projection to the year 2000, using a sectorial economic model to forecast demand, expects energy demand will grow, on average, by 3.39%/year and electrification will grow by 2.93%/year. New energy technologies (geothermal, wind, solar) are not expected to contribute a large portion to total U.S. energy supplies by the year 2000.

The ERDA projection to the year 2000, using a series of macroeconomic/inter-industry growth and energy system optimization models, anticipates energy demand will grow on average by 2.63%/year, and electrification will grow by 2.13%/year. Electrification is lower in the ERDA projection than in the FERC projection because it is anticipated that new energy technologies will compete with the steam electric industry in supplying the nation's energy needs by the year 2000.

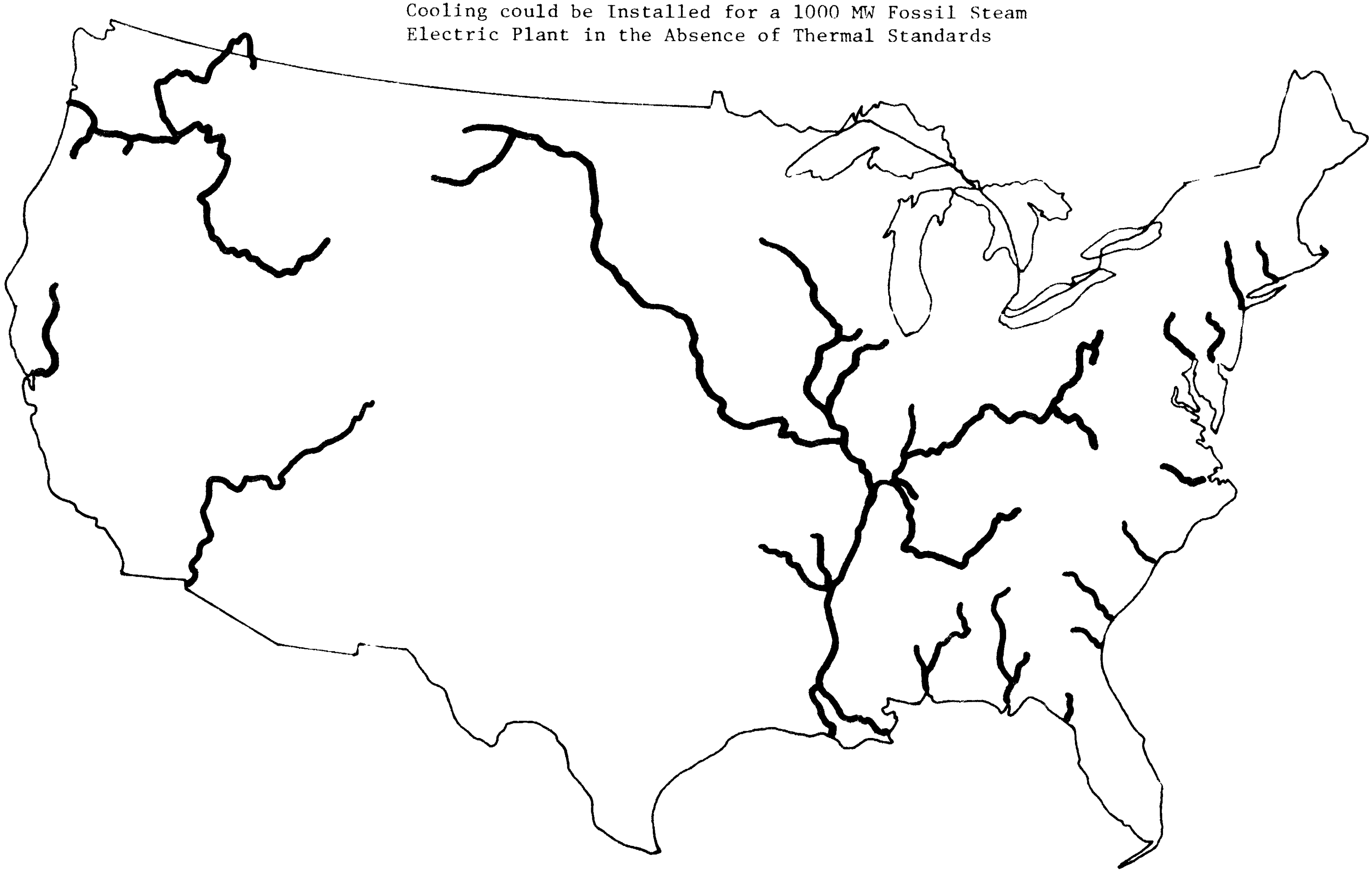
2.3 New Once-Through Cooling Development

In this section we evaluate how new once-through cooling could develop in the future under both current and relaxed thermal regulations. For this purpose we speculate how the geographic distribution of new plants might appear with the current restrictions on once-through cooling and compare these with siting patterns we could expect if these restrictions are relaxed.

It is worth emphasizing that even without environmental controls, once-through cooling is constrained by water availability. A once-through cooling system for a typical 1000 MWe fossil plant will withdraw between 750-1500 cfs from the nearby source of water and will require this flow with a very high reliability. This condition is met at coastal sites, on large lakes and along large rivers, the latter being predominately east of the Mississippi. Using the 7 day 10 year low flow as a measure of reliability, Figure 2.2 indicates the locations of river segments in the contiguous United States that can support the use of once-through cooling at large fossil steam electric power plants in the absence of environmental controls.

Our estimates of the proportion of new electric capacity to be installed between 1975 and 2000 which might use once-through cooling under

Figure 2.2 Location of Rivers in the United States where Once-Through Cooling could be Installed for a 1000 MW Fossil Steam Electric Plant in the Absence of Thermal Standards

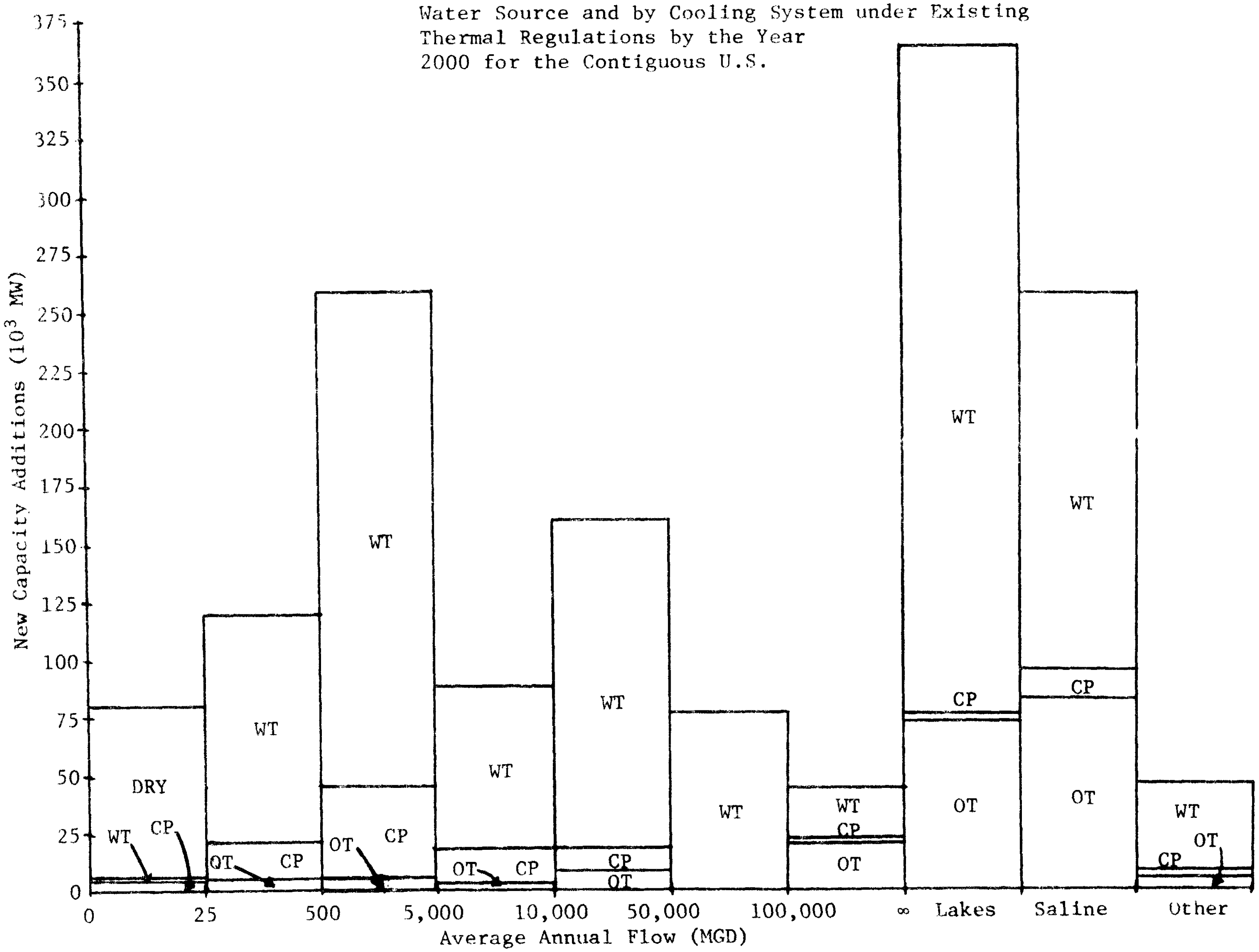


current thermal regulations come from the FERC projections introduced earlier. From a survey taken of the electric power industry, FERC locates existing and future plants by aggregated sub-area (ASA) within each WRC Region and by water source within each ASA. In addition the FERC projection specifies the cooling system(s) anticipated for each new plant, thereby reflecting what the utility industry expects will be the status of once-through cooling for new plants under existing and anticipated water quality regulations. The histogram in Figure 2.3, derived from the FERC projections, illustrates projected installed capacity by cooling system type (dry tower, wet tower, pond or once-through) and by location to the type of cooling water body. These estimates indicate that, nationally, 12.9% of new installed capacity will use once-through and 87.1% will utilize some sort of closed cycle cooling under existing thermal regulations.

Although the FERC projections reflect the high energy demand projection, we feel the same percentages of new capacity going to once-through cooling could be applied to the ERDA low energy demand scenario. The only alteration necessary to go from the high demand forecast to the low demand one is a reduction in capacity at each of the new plant sites given in the FERC projection to account for the lower overall capacity growth in the ERDA forecast.

Thus for both the high energy demand case and for the low energy demand case we use the FERC once-through cooling development projection to represent the percentage of new plants which would use once-through cooling under existing regulations. Tables 2.2 and 2.3 indicate these percentages, by WRC region, for the high and the low energy demand scenarios, respectively.

Figure 2.3 Expected Distribution of New Capacity by Cooling Water Source and by Cooling System under Existing Thermal Regulations by the Year 2000 for the Contiguous U.S.



WT = Wet Towers, OT = Once Through, CP = Cooling Ponds, DRY = Dry Towers

Table 2.2 Percentages of New Capacity Expected to be Installed Between 1975 and 2000 that could use Once-Through Cooling (High Energy Demand Scenario)

Water Resource Council Region	With Current Thermal Regulations	With Relaxed Thermal Regulations Alternative Siting Patterns:			
		One	Two	Three	Four
One	25.3	91.0	67.1	75.6	100.0
Two	13.9	59.0	42.1	66.4	94.1
Three	11.2	26.0	39.3	57.9	64.5
Four	7.0	81.0	70.1	100.0	100.0
Five	3.2	62.0	16.7	24.6	24.6
Six	2.6	61.0	15.2	47.8	47.8
Seven	0.9	78.0	13.4	28.3	33.0
Eight	42.5	100.0	61.1	71.8	88.8
Ten	8.2	54.0	24.8	33.1	33.1
11-17	15.6	36.0	27.8	46.3	47.3
Eighteen	43.1	78.0	47.2	77.3	100.0
Contiguous U.S.	12.9	54.0	35.6	54.0	60.9

Table 2.3 Percentages of New Capacity Expected to be Installed Between 1975 and 2000 that could use Once-Through Cooling (Low Energy Demand Scenarios)

Water Resource Council Region	With Current Thermal Regulations	With Relaxed Thermal Regulations Alternative Siting Patterns:			
		One	Two	Three	Four
One	25.3	91.0	71.3	77.7	100.0
Two	13.9	57.0	44.1	90.1	100.0
Three	11.2	26.0	48.1	76.6	100.0
Four	7.0	81.0	76.7	100.0	100.0
Five	3.2	63.0	24.7	40.9	41.2
Six	2.6	59.0	27.2	82.4	87.4
Seven	0.9	78.0	16.9	37.4	52.0
Eight	42.5	100.0	66.4	100.0	100.0
Ten	8.2	53.0	28.2	51.6	51.8
11-17	15.6	36.0	34.6	60.9	72.6
Eighteen	43.1	100.0	46.4	76.7	100.0
Contiguous U.S.	12.9	50.0	42.3	69.4	83.9

To estimate the percentage of new plants which might use once-through cooling under more lenient regulations than are currently in effect, we postulate a number of alternative siting and cooling system selection patterns which reflect this leniency, using the siting patterns originally indicated in the FERC model as our guides. The favorable feature of the FERC siting patterns is that they account for many of the siting criteria utilities normally consider when locating new plants. These criteria include site proximity to load demand and fuel source, population density in the neighborhood of the site, and location with respect to the existing and anticipated system grid. In practice, the cooling system options available at a site (e.g. the possibility of accomodating once-through cooling) also serve as criteria for plant location. However, since the FERC siting patterns reflect anticipated restrictions of the use of once-through cooling for new plants, these patterns place less emphasis on the possibility of using once-through cooling at any potential site than they would were these restriction lifted.

In speculating how once-through cooling might be used under relaxed thermal controls, we attempt to correct the earlier bias against this mode of cooling found in the FERC projections by placing a greater emphasis on using once-through cooling systems in our alternative siting patterns. For this purpose, we consider four alternative patterns: one that applies engineering considerations to determine whether once-through cooling may be located on particular bodies of water, and three that apply relaxed themal standard criteria for using once-through cooling.

Alternative Pattern 1 (Extension of Historical Patterns)

Here, we locate new power plants in every aggregated sub area in WRC

Regions 1-12, 17 and 18 on major bodies of water, following the same distributions by water source that were observed before 1973. In this manner the siting patterns found in these sub areas before 1975 are replicated for the years 1975-2000. Historically, open-cycle cooling has been of little consequence in WRC Regions 13-16, and, consequently, we do not assess in detail the once-through cooling potential in these four regions. In addition, prior to 1973, once-through cooling was installed at relatively few plants in regions 11, 12 and 17. Therefore, for this siting pattern we lump our results for regions 11-17 in a single catagory. For our high energy demand scenario, we use the FERC projections by ASA to estimate how many megawatts of new fossil and new nuclear capacity will be installed in every ASA between 1975 and 2000. The projections for new capacity additions by ASA are scaled down in the low energy demand scenario to account for the overall lower rates of capacity expression incorporated in this scenario. In locating new capacity additions to resemble pre-1975 patterns, we assume that new fossil plant sizes will not exceed 800 MW and that new nuclear plant sizes will not exceed 1200 MW. We make the assumption that capacity located on lakes and oceans will use once-through cooling. On river sites, the feasibility of once-through cooling is based on historical relationships involving the ratio of average annual river flow to the size of the station. Based on an analysis of plants built before 1973, it was found that a ratio of 10 mgd/MWe separated plants using closed cycle from plants using open cycle cooling. Thus in this hypothetical plant siting scenario an average annual river flow of at least 10 mgd/MWe served as the minimum acceptable flow in order to use once-through cooling on any river. In our opinion this ratio represents a conservative estimate of the flow necessary for the use of once-through cooling based on engineering and reliability considerations. Because this criterion reflects engineering rather than environmental considerations, the cumulative thermal effects among new and existing plants are not considered.

Tables 2.2 and 2.3 indicate the percentage, by Water Resource Council Region, of new capacity which could utilize once-through cooling under this pattern. Nationally, the percentages are 54% and 50% for the high and low energy demand scenarios respectively. Further details of our analysis are presented in Appendix A-1.

Alternative Pattern 2 (Maximize Once-Through Cooling using FERC Siting under Relaxed Regulations)

Unlike Pattern 1 where we locate new plants according to historic patterns, we retain all the new sites that are identified in the FERC projections as well as maintain the same projected capacity at each site. Moreover, the criteria for using once-through cooling at every site is different from the criteria used in Pattern 1, and is based on a maximum allowable temperature rise at the edge of a mixing zone. While this criteria is more restrictive in allowing once-through cooling at any one site than the engineering criteria of 10 mgd/MWe used in Pattern 1, we feel the allowable temperature rise considered here is more lenient than current standards. The allowable temperature rise is approxiamately 5°F for lakes and for rivers at low flow, with the low flow in rivers defined as the lowest monthly flow expected every twenty years. For sites on estuaries and open coasts the amount of allowable once-through cooling is determined by the relative openness of the sites and ranges from a minimum of 1000 MW per site for enclosed estuarine sites to a maximum of 5000 MW per site for sites on the open coast. Further details are included in Appendix A1.

Tables 2.2 and 2.3 indicate the percentage of plants by Water Resource Council Region that could install once-through cooling under this siting pattern for the high and low energy demand scenarios, respectively. Nationally, these percentages are 35.6% and 42.3% for the high and low energy scenarios, respectively. Comparing these percentages with the percentages expected under current regulations, it is apparent that the limitations on once-through cooling suggested by this pattern represent a liberal relaxation over current standards. (Few states have water quality standards allowing a temperature rise greater than 5°F, while almost all set lower allowable increases for lakes in general as well as for streams that are classified as cold water fisheries; Peterson, et al., 1973).

Alternative Pattern 3 (Maximize Once-Through Cooling by Aggregated Sub-Area)

In Pattern 2 all we have done is to switch from using closed cycle cooling at a designated FERC site to open cycle cooling provided the lenient thermal standards are not violated in doing so. Nevertheless, because all the original FERC sites are maintained, the siting patterns found in Pattern 2 reflect the same bias against using the potential for installing once-through cooling as a siting criteria for new plants that was found in the FERC siting pattern. We attempt to correct this bias by considering in Pattern 3 modifications which reflect a greater potential for using once-through cooling at new sites.

Here, as in Pattern 2, we use FERC sites and adopt the same 5°F nominal temperature rise limitation. However we modify the old siting pattern by relocating capacity within each ASA from sites which have no remaining once-through cooling potential to sites with potential remaining. Thus, we relax the siting criteria implied in the original FERC forecast to accomodate additional once-through cooling; the overall generation patterns implied in the FERC projections need hold only down to the ASA level and not at every site indicated by FERC. The regional breakdown of allowable once through cooling based on this pattern is included in Tables 2.2 and 2.3. Nationally, the percentages are 54.0% and 69.4% for the high and low energy demand scenarios respectively.

<u>Alternative Pattern 4</u> (Maximize Once-Through Cooling by Water Resource Council Region)

Here, as in Patterns 2 & 3, we use FERC sites and adopt the same 5°F nominal temperature rise criteria for once-through cooling. However, we modify the FERC patterns further still by relocating new capacity within each WRC region from aggregated sub-areas having no remaining once-through cooling to ASA's with potential remaining. By allowing this redistribution of capacity between ASA's we have greatly relaxed the FERC siting criteria to accomodate once-through cooling by assuming the non-cooling siting criteria implied in the FERC projection need be maintained only down to the broad regional level. The regional breakdown of allowable once-through cooling based on this pattern is included in Tables 2.2 and 2.3. Nationally, the percentages are 60.9% and 83.9% for the high and low energy demand scenarios, respectively.

Summarizing the results of our analysis so far, for two energy demand scenarios we have estimated the net number of megawatts in electric generating capacity which we feel will be required to install closed cycle cooling systems to comply with current thermal regulations restricting further once-through cooling development. Our proceedure has been to take a proposed future plant siting pattern which reflects a heavy bias against the further use of once-through cooling and, in a sequential manner, modify the pattern to reflect an ever increasing emphasis on the potential for using once-through cooling as a siting criteria. Tables 2.2 and 2.3 provide estimates of the percentages, by Water Resource Council Region, of new plants whcih could utilize once-through cooling for each of the four alternative plant siting and cooling system selection patterns which allow more liberalized use of once-through cooling. Nationally, these percentages range from 35.6% to 60.9% for the high energy demand scenario and from 42.3% to 83.9% for the low energy demand scenario. These numbers are in sharp contrast to the 12.9% projected by the electric utility industry given the current thermal regulations.

One could offer the criticism that our siting pattern modifications are arbitrary in the sense that our plant relocations are constrained by hydrologic boundaries (WRC Region and sub-area boundaries). In reality, utilities are more likely to be constrained by service area and/or electric reliability council boundaries when relocating proposed plants. While this criticism is well taken we can compare our estimates of new capacity that would be able to use once-through cooling were thermal controls to be removed/relaxed with estimates from a survey made by National Economic Research Associates (NERA). NERA conducted a survey

Table 2.4 NERA Survey Results Indicating Cooling System Use for New Proposed Generating Capacity to be Installed Between 1977-1990

	Total Additions	Once-Through Cooling	Man-Made Lakes Open Cycle	Man-Made Lakes Closed Cycle	Closed Cycle Cooling
	280,968	38,695	7,171	48,810	186,292
%	100.0	13.8	2.6	17.4	66.3

Ref.: UWAG (1978)

for the Utility Water Act Group (UWAG) to determine the percentage of new proposed capacity that will be required to use closed cycle to comply with thermal control regulations.

The NERA survey identified four alternative cooling system configurations: once-through cooling on oceans and rivers, once-through cooling on man made lakes, closed cycle cooling on man made lakes, and closed cycle cooling not located on man-made lakes. Table 2.4 presents their survey results indicating the number of megawatts proposed for commercial operation between 1977 and 1990 that are tentatively planned to operate with each of the four cooling systems.

Utilities proposing to operate plants with closed cycle cooling not on lakes were asked to identify the reasons for their choice. Possible reasons included engineering/economic factors, need to comply with state water quality standards, need to comply with federal water quality standards or any combinations among these three. The NERA results indicated that 48.3% of the new capacity that will be installed with closed cycle cooling, with the exception of closed cycle cooling on man made lakes, will do so wholly to comply with state and federal thermal regulations. While the NERA results do not indicate what percentage of the new capacity planning to use closed-cycle cooling on man made lakes will do so to comply with thermal regulations, it may be reasonable to assume it is roughly equivalent to the percentage indicated for the other closed cycle cooling category. Making this assumption, the percentage of the new capacity proposed to be brought into commercial operation between 1977 and 1990 that will use closed cycle cooling wholly in response to thermal regulations is:

$$100 \times \frac{.483\ (186{,}292 + 48{,}810)}{280{,}968} = 40.4\%$$

The NERA results indicated that 85.6% of the new capacity that will be installed with closed cycle cooling, with the exception of closed cycle cooling on man made lakes, will do so for environmental and joint engineering/economic/environmental resons. Again, it may be reasonable to apply this same percentage to closed cycle cooling located on man-made lakes. Making that assumption, the percentages of the new capacity proposed to be brought into commercial operation between 1977 and 1990 that will use closed cycle cooling because of environmental and joint engineering/economic/environmental factors is:

$$100 \times .856\ \frac{(186{,}292 + 48{,}810)}{280{,}968} = 71.6\%$$

Table 2.5 compares our estimates of the percentage of new capacity that will install closed cycle cooling for environmental reasons and NERA's estimates for the same. For the high energy demand scenario we estimate that between 22.7% and 48% of the new capacity planned to be built between 1975 and 2000 will be required to comply with thermal regulations while for the low energy demand scenario the range is between 29.5% and 71.1%. As noted our interpolation of the NERA survey results suggests 40.5% of the new capacity planned to 1990 will use closed cycle cooling (lake and non lake) to comply with thermal standards alone and 71.6% will use closed cycle cooling either wholly or partially in response to thermal regulations.

Examining Table 2.5 we observe that our projections of the per-

Table 2.5 Comparison Between NERA's Estimates of the Percentage of New Capacity that will Install Closed Cycle Cooling for Environmental Reasons and this Study's Estimates of the Same

NERA		This Study Alternative Siting Patterns**				
		One	Two	Three	Four	
40.5%*	71.6%†	41.1%	22.7%	41.1%	48.0%	High Energy Demand
		37.1%	29.4%	56.5%	71.0%	Low Energy Demand

*Percentage installing closed cycle cooling wholly for environmental reasons

†Percentage installing closed cycle cooling either wholly or partially for environmental reasons

**Percentage installing once-through cooling under each alternative siting scenario minus the percentage expected to install once-through cooling under the FERC forecast.

Ref: UWAG (1978)

centages of new capacity that will install closed cycle cooling solely to comply with environmental regulations from siting pattern scenarios 1 and 3 do not differ greatly from the percentages indicated in the NERA study. This suggests that while our siting pattern modifications may not reflect precisely how these modifications would actually be realized, their results are nevertheless comensurate with the independent NERA study.

The development of the four alternative generations patterns describing possible levels of future once-through cooling development under relaxed thermal regulations offers us the opportunity to examine a range of possible outcomes were current controls to be relaxed. In addition, this range offers us a basis for comparison with similar results from other studies. For our cost analysis presented later in this report we chose one pattern out of our four to describe future once-through cooling development under relaxed controls. We use Pattern 1 (Extrapolation from Historic Trends) because the percentages given by this patterns are representative of both the four patterns we have developed and the NERA survey results presented earlier.

For our estimates of the costs of current thermal standards, to be presented in chapter Four, we assume new fossil and new nuclear capacity additions to the year 2000 will be linearly distributed over time. Tables 2.6 and 2.7 indicate the number of megawatts of new capacity that will be installed with closed cycle cooling for environmental reasons, in five year intervals, under Alternative Pattern 1 for the high and low energy demand scenarios, respectively.

Table 2.6 Estimated Megawatts of New Capacity Requiring Closed Cycle Cooling for Purposes of Meeting Environmental Standards under the High Energy Demand Scenario

WRC Region	1975-1980		1980-1985		1985-1990		1990-1995		1995-2000		Saline*	
	F	N	F	N	F	N	F	N	F	N	F	N
One	2,200	3,900	2,200	3,900	2,200	3,900	2,200	3,900	2,200	3,900	80%	47%
Two	4,300	9,000	4,300	9,000	4,300	9,000	4,300	9,000	4,300	9,000	80%	76%
Three	3,800	6,400	3,800	6,400	3,800	6,400	3,800	6,400	3,800	6,400	4%	3%
Four	7,500	13,000	7,500	13,000	7,500	13,000	7,500	13,000	7,500	13,000	0%	0%
Five	10,200	11,000	10,200	11,000	10,200	11,000	10,200	11,000	10,200	11,000	0%	0%
Six	960	3,200	960	3,200	960	3,200	960	3,200	960	3,200	0%	0%
Seven	6,300	12,600	6,300	12,600	6,300	12,600	6,300	12,600	6,300	12,600	0%	0%
Eight	3,200	6,200	3,200	6,200	3,200	6,200	3,200	6,200	3,200	6,200	0%	0%
Ten	4,500	3,100	4,500	3,100	4,500	3,100	4,500	3,100	4,500	3,100	0%	0%
11-17	2,500	11,400	2,500	11,400	2,500	11,400	2,500	11,400	2,500	11,400	44%	23%
Eighteen	1,100	2,200	1,100	2,200	1,100	2,200	1,100	2,200	1,100	2,200	100%	100%
Total	46,600	82,000	46,600	82,000	46,600	82,000	46,600	82,000	46,600	82,000		

*Estimated percentage of new capacity that will install closed cycle cooling to meet environmental standards but would install coastal once-through cooling without standards.

Table 2.7 Estimated Megawatts of New Capacity Requiring Closed Cycle Cooling for Purposes of Meeting Environmental Standards under the Low Energy Demand Scenario

WRC Region	1975–1980		1980–1985		1985–1990		1990–1995		1995–2000		Saline*	
	F	N	F	N	F	N	F	N	F	N	F	N
One	1,300	2,400	1,300	2,400	1,300	2,400	1,300	2,400	1,300	2,400	80%	47%
Two	2,500	5,300	2,500	5,300	2,500	5,300	2,500	5,300	2,500	5,300	80%	76%
Three	2,300	3,900	2,300	3,900	2,300	3,900	2,300	3,900	2,300	3,900	4%	3%
Four	4,800	8,300	4,800	8,300	4,800	8,300	4,800	8,300	4,800	8,300	0%	0%
Five	6,000	6,500	6,000	6,500	6,000	6,500	6,000	6,500	6,000	6,500	0%	0%
Six	550	1,800	550	1,800	550	1,800	550	1,800	550	1,800	0%	0%
Seven	4,000	8,000	4,000	8,000	4,000	8,000	4,000	8,000	4,000	8,000	0%	0%
Eight	2,000	3,800	2,000	3,800	2,000	3,800	2,000	3,800	2,000	3,800	0%	0%
Ten	2,900	2,000	2,900	2,000	2,900	2,000	2,900	2,000	2,900	2,000	0%	0%
11-17	1,500	6,900	1,500	6,900	1,500	6,900	1,500	6,900	1,500	6,900	44%	23%
Eighteen	1,100	2,100	1,100	2,100	1,100	2,100	1,100	2,100	1,100	2,100	100%	100%
Total	29,000	51,000	2,900	51,000	29,000	51,000	29,000	51,000	29,000	51,000		

*Estimated percentage of new capacity that will install closed cycle cooling to meet environmental standards but would install coastal once-through cooling without standards.

III COMPARISONS OF COST AND RESOURCE CONSUMPTION BETWEEN OPEN AND CLOSED CYCLE COOLING SYSTEMS: INDIVIDUAL PLANT LEVEL

3.1 Introduction

This chapter presents the methodology we use to estimate the incremental costs and resource commitments associated with the use of closed-cycle cooling over once-through cooling. Costs are estimated by plant type (fossil or nuclear) and by year (1975 to 2000) for every Water Resource Council Region using the cooling system simulation codes developed in the course of our earlier work (Najjar, 1978). The results from these codes are expressed as unit incremental annual costs ($/MWe) for five year periods up to the year 2000. In addition incremental fuel consumption rates (BTU/MWe) and water consumption rates (acre-ft/MWe) are computed. The product of these unit costs and rates times the amount of new capacity installed between 1975 and 2000 that will be required by water quality regulations to use closed-cycle cooling represents the annual cost and resource commitments implied by current thermal controls to the year 2000.

The first section of this chapter gives a brief description of the general plant/cooling system performance simulation algorithms we use and some arguments for using the approach we do. Greater detail is presented in our earlier work (Najjar, et al., 1978). The next two sections describe the criteria with which we select the economic and meteorologic/hydrologic parameters incorporated in our simulation codes. The final section presents the results from these simulation runs.

3.2 Simulation Algorithm

We select mechanical draft freshwater evaporative towers as the representative closed cycle alternative to once-through cooling with a surface discharge. Two other closed cycle systems, cooling ponds and natural draft towers, are often competitive with mechanical draft towers; however, installation and generating costs for these two are more site specific than are the costs for mechanical draft towers. Given the infeasibility of analyzing all potential sites in all regions we believe it is reasonable to consider only mechanical draft towers.

Two representative plant types are chosen in our simulations: a fossil unit facing an 800 MW base-load demand and a nuclear unit facing a 1200 MW base-load demand. Capacity factors for each plant are 0.75. In each region, cost comparisons between closed-cycle and open-cycle cooling for the two plants are made by comparing optimal configurations for each cooling system type. The optimal configuration is determined by varying the size of the power plant and the cooling system to find that configuration with the lowest combination of capital and operating costs. For once-through systems we vary the flow rate through the condenser; for closed cycle we vary the size of the towers. In general, larger system sizes have higher capital costs, but are more consistent in maintaining efficient plant operating conditions, thereby leading to lower penalty costs. An optimum can usually be found at some intermediate size. The optimal configuration for any cooling system will depend on the specific plant operation conditions, the meteorology and/or hydrology at the plant site and a number of economic factors (Najjar, 1978; Sebald, 1976; Croley, et al., 1975; United Engineers, 1974). Plant operating conditions include plant capacity, specified constraints on the turbines' operation (e.g. back pressure limitations) and the operating lifetime of the unit. The relevant economic factors include current and anticipated future prices for fuel, prices for replacement energy and cooling system make-up water, plant and equipment costs and the capital amortization factor.

Specific equipment costs for once-through systems include expenditures for intake and discharge structures, for the condenser and for pumphouse and electrical equipment. For evaporative towers, equipment costs include expenditures for tower structures and foundations, for the condenser and for pumphouse and electrical equipment.

The base year (1977) capital costs for once-through cooling systems operating with surface intake and discharge canal structures are from Najjar (1978) and are expressed by the following equations:

Fossil unit:

$$CCAP = 1.537 \times F^{0.348} \qquad 150 \leq F \leq 400$$

Nuclear unit:

$$CCAP = 0.632 \times F^{.525} \qquad 400 \leq F \leq 1000$$

where:

CCAP = cooling system capital cost ($ millions)

F = condenser flow rate (1000 gpm)

The base year capital costs for mechanical draft towers also come from Najjar (1978) and are expressed by the following equations:

Fossil unit:

$$CCAP = 5.41 + 1.68 \times TL \qquad 4 \leq TL \leq 8$$

Nuclear unit:

$$CCAP = 7.08 + 1.75 \times TL \qquad 8 \leq TL \leq 13$$

where:

TL = tower length (100 ft)

The equations for capital cost account for all component costs with the exception of replacement capacity capital costs. (See Tables 3.3 and 3.4)

Our capital cost estimates for open-cycle and tower cooling systems incorporate a number of simplifications which would not appear in actual practice. In practice a number of cooling system components are designed and integrated into the complete cooling system on the basis of site specific sub-optimization studies. Additionally, in practice mechanical draft tower capital costs are determined by a number of site specific design performance parameters (Crowley, 1975; Najjar, 1978; Dickey and Cates, 1973). Our capital cost equations for both open-cycle and tower cooling systems are based on a single set of sub-optimization studies and design performance parameters that were applicable to a mid-western (Illinois) site examined in an earlier work (Najjar, et al., 1978).

The plant operating lifetime enters in the determination of costs by setting the number of years over which plant and equipment are amortized. Furthermore, given the expectation that real prices for fuel and other inputs will change with time, the plant lifetime and the initial year of operation, together, set the range of input prices within which a plant will operate.

Our simulation codes evaluate system costs as the sum of capital, operating, and penalty costs, using a fixed demand, scalable plant concept. (See Fryer; 1976.) Transmission costs are not included. Open-cycle cooling performance is governed by ambient water temperatures while evaporative tower performance is governed by wet-bulb temperatures. For each site a discrete annual frequency distribution is compiled for both ambient water temperature and wet bulb temperature based on their historical probability of occurrence. A plant must meet a constant electrical demand through a combination of its power output plus additional energy purchases, when necessary. For any plant/cooling system combination the model records expenditures for fuel consumed directly by the plant plus expenditures for outside energy purchases (penalty costs) that are necessary to meet this demand during each environmental condition. The sum of every year's operating costs discounted to the initial year of operation is then added to the capital cost (plant + cooling system + replacement capacity required during the worst environmental condition expected in a year) to give the total cost of owning and operating that particular plant/cooling system configuration.

Our simulation codes include a scaling sub-optimization routine which, for a fixed cooling system size, seeks the least expensive combination of base-load steam plant capacity and combustion turbine capacity necessary to meet a constant electrical demand. Since base load steam capacity is more expensive to install but less expensive to operate than combustion turbine capacity, there is an optimal combination of these two capacities which will supply the fixed demand for a fixed cooling system size.

In summary, then, our simulation codes search for both the once through cooling system and the tower cooling system with the minimum present valued cost of operation for a representative plant in any region by solving the following equation:

$$\begin{aligned}\underset{j}{\mathrm{Min}}\ TC^{j}_{\ell,T,g} = {} & PCAP_{\ell,T,g} \cdot SF^{j}_{\ell,T,g} + CCAP^{j}_{\ell,T,g} + ECAP^{j}_{\ell,T} \\ & + \sum_{i=T}^{N+T} [\{\sum_{k=1}^{M} (FCON^{j}_{k,\ell,g} \cdot FC^{i}_{\ell,g} + ECON^{j}_{k,\ell,g} \\ & \cdot EC^{i}_{\ell}) \cdot P_{k,\ell} \cdot CAPFAC + MC^{j}_{\ell,T,g}\} \\ & \cdot (1+r)^{-(i-T+1)}\end{aligned}$$

subject to the constraints

$$ECON^{j}_{k,\ell,g} + FCON^{j}_{k,\ell,g} \cdot EFF^{j}_{k,g} = DEMAND_{g} \quad \text{for all } g,j,k,\ell$$

$$ECON^{j}_{k,\ell,g} \geq 0 \qquad \text{for all } j,k,\ell$$

$$FCON^{j}_{k,\ell,g} \leq MAXCON_{g} \qquad \text{for all } g,j,k,\ell$$

plus specific turbine and cooling system operation constraints where:

$TC^{j}_{\ell,T,g}$ = present valued cost of owning and operating a plant of fuel type g brought on line in year T, in region ℓ, and installed with cooling system size j ($)

$PCAP_{\ell,T,g}$ = Capital cost ($1977) for a baseload plant of fuel type g brought on line in year T in region ℓ ($)

$SF^{j}_{\ell,T,g}$ = Optimized plant scaling factor for a baseload plant of type g, brought on line in year T in region ℓ and installed with cooling system size j

$CCAP^{j}_{\ell,T,g}$ = Capital cost ($1977) for a cooling system of size j, installed with plant type g in year T in region ℓ ($)

$ECAP^{j}_{\ell,T,g}$ = Capital ($1977) cost for replacement capacity necessary for a baseload plant of type g installed with a cooling system of size j in year T in region ℓ. ($)

T = Initial year of operation

N = Plant/cooling system lifetime

M = Number of meteorologic or hydrologic conditions simulated in a year

$FCON^{j}_{k,\ell,g}$ = Fuel consumption from plant g operating with a cooling system of size j during environmental condition k in region ℓ (BTU/hr)

$FC^{i}_{\ell,g}$ = Fuel cost ($1977) for plant type g in year i in region ℓ ($/BTU)

$ECON^{j}_{k,\ell,g}$ = Replacement energy consumption for plant type g operating with a cooling system of size j during environmental condition k in region ℓ (MWe/hr)

EC_{ℓ}^{i} = Replacement energy cost in year i in region ℓ (\$/MWe)

$P_{k,\ell}$ = Expected duration of environmental condition k in an average year in region ℓ (hours)

$MC_{\ell,T,g}^{j}$ = Annual miscellaneous costs for plant type g, cooling system size j, installed in year T in region ℓ (\$/year)

CAPFAC = Annual Capacity Factor

r = Constant dollar discount rate

$EFF_{k,g}^{j}$ = Thermal efficiency of steam plant g operating with cooling system j during environmental condition k ($\sim$ 33% for nuclear units; $\sim$ 40% for fossil units)

$DEMAND_g$ = Electrical demand on plant type g (MW)

$MAXCON_g$ = Maximum sustainable fuel consumption for steam plant g (BTU/hr)

The above formulation expresses the present valued cost of operation (\$) of a particular plant/cooling system configuration. From this it is possible to compute the annual cost of operation (\$/year) by assigning an annual fixed charge rate to amortize the capital costs. Thus the cost in any year of operating a plant installed with the optimal cooling system configuration j^* built in year T in region ℓ is thus:

$$AC^{i}_{\ell} = \{PCAP_{\ell,T,g} \cdot SF^{j^*}_{\ell,T,g} + CCAP^{j^*}_{\ell,T,g} + ECAP^{j^*}_{\ell,T,g}\} \cdot FCR +$$

$$+ \sum_{k=1}^{M} (FCON^{j^*}_{k,\ell,g} \cdot FC^{i}_{\ell,g} + ECON^{j^*}_{k,\ell,g} \cdot EC^{i}_{\ell})$$

$$\cdot P_{k,\ell} \cdot CAPFAC + MC^{j^*}_{\ell,T,g}$$

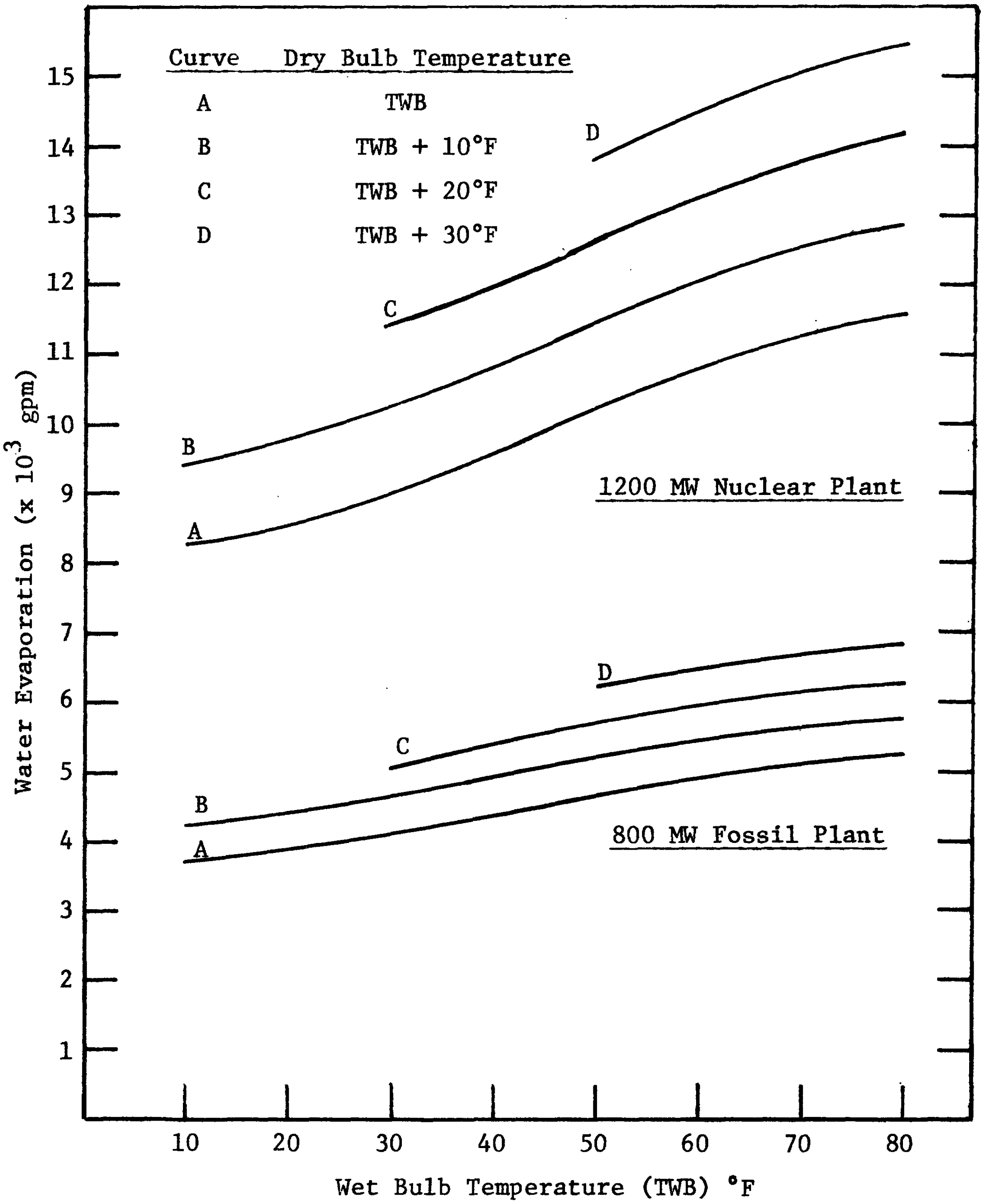
where:

AC^{i}_{ℓ} = Annual cost in year i ($)

FCR = Fixed charge rate (annualization factor)

Once the optimal cooling system has been identified the annual fuel and water consumption can be computed. Fuel consumption comes from the two terms $FCON^{j^*}_{k,\ell,g}$ and $ECON^{j^*}_{k,\ell,g}$ in the previous equation. Mechanical draft tower water consumption is a function of the ambient dry bulb and wet bulb temperatures, fill geometry and turbine operating characteristics. Figure 3.1 illustrates the functional relationship between evaporation and the ambient dry bulb/wet bulb temperatures for a 1200 MWe BWR nuclear unit operating with a 1200 foot mechanical draft tower, and for an 800 MWe coal unit operating with an 500 foot mechanical draft tower. Joint dry bulb/wet bulb temperature frequency distributions for specific sites of interest were not readily available and so for the report our water consumption rates are based on an average evaporation rate at every wet bulb temperature. We do not calculate water consumption from once through cooling directly, but assume the annual water consumption from an optimal once-through system is 71% of the annual consumption from its tower counterpart. This percentage which is from

Figure 3.1 Evaporation from Representative Wet Towers as a Function of Wet-Bulb Temperature (TWB) and Dry-Bulb Temperature (TDB)



our site specific study (Najjar, 1978) is very similar to the average value of 69% cited by Hendrickson (1978).

3.3 Site Selection by Region

Separate hydrologic/meteorologic parameters are used for each Water Resource Council Region. Because environmental conditions can exhibit considerable variation within regions, particularly in those that cover areas of hundreds of thousands of square miles, it is necessary to develop criteria with which to select a "representative" site for each region.

From our scenarios describing once-through cooling potential presented in Chapter 2, we select for each region the aggregated sub area (ASA) which would have the greatest new once-through cooling capacity without thermal regulations. We then examine the historical pattern of plant location within that ASA to locate our "representative" site.

At each site synthetic monthly wet bulb temperature distributions are generated from monthly mean and monthly twelve hour continuous exceedence temperatures. (U.S. Dept. of Commerce, 1977). We assume monthly distributions are normal and use the twelve hour continuous exceedence temperature in each month as an approximation to the temperature exceeded for twelve hours in total for that month. There is, of course, an error in this approximation as the temperature which is exceeded for no more than twelve continuous hours in a month is likely to be exceeded for more than twelve hours total. Therefore while the temperature exceeded a total of twelve hours in a month represents a 1.66% frequency of exceedence on a normal distribution we introduce a small correction term and assume the twelve-hour continuously exceeded temperature represents a 2% frequency of exceedence on a normal distribution. The twelve synthetic monthly temperature distributions at a site are aggregated into the annual wet/bulb temperature distributions we use in our simulation models.

3.4 Economic Parameters

Prices for fuel and replacement energy exhibit both inter-regional and intra-regional variation. Intra-regional price variation is due in part to the fact that the boundaries which define a particular Water Resource Council region are not the same as those that influence input prices. Water resource region boundaries are set by hydrologic conditions: major river basins, coastal areas and, in the case of the Great Lakes Region, the location of large lakes. Fuel prices, on the other hand, are influenced by location to major fuel reserves, by state boundaries and, in many instances, by the boundaries of utility service areas.

Inter-regional price variations are generally larger than intra-regional variations, although this depends on the commodity considered. Coal prices show the greatest inter-regional variation with as much as a two fold difference in the average price among regions. Inter-regional variations in prices for oil and natural gas are moderate, while variation in nuclear fuel prices is generally quite small.

We specify separate fossil fuel prices for each region and assume nuclear fuel prices are uniform for all regions. (See Table 3.3.) This approach is similar to one adopted by EPRI/SRI(1977). The relative fossil fuel price variation among regions is consistent with the variation observed for the year 1975.(U.S. Dept. of Energy, January 1978; National Coal Association, 1976; Edison Electric Institute Yearbook, 1976).

The projected future price escalation factors we use in our performance simulations come from the published literature. There is considerable variation found among projections (Table 3.1). Differing assumptions among projections regarding future demand for electricity (and energy), equipment and fuel supplies and government policies all contribute to the observed variation.

Although we expect price escalation rates will differ from region to region, we do not have sufficient information with which to specify separate rates for each region. Thus we assume escalation rates will apply uniformly over the entire United States. From the range of escalation rates found in Table 3-1 we consider a high price scenario and a low price scenario. The escalation rates for plant and equipment costs and for fuel and replacement energy prices associated with these two scenarios are presented in Table 3.2.

All prices used in our study are in 1977 dollars. The last year for which we have detailed fuel and replacement energy costs by region is 1975 and the last year for which we have U.S. average costs for fuel and replacement energy is 1977. Therefore, the 1980, base year prices for fuel and replacement energy in each region are calculated as follows:

$$FC_{\ell,g}^{1980} = (1 + FCE)^3 \cdot \frac{FC_{\ell,g}^{1975}}{\overline{FC}_g^{1975}} \cdot \overline{FC}_g^{1977}$$

$$EC_{\ell}^{1980} = (1 + ECE)^3 \cdot \frac{EC_{\ell}^{1975}}{\overline{EC}^{1975}} \cdot \overline{EC}^{1977}$$

where:

FCE = Fuel cost escalation rate for a particular price scenario

ECE = Replacement energy escalation rate for a particular price scenario

$\overline{FC}_g^i$ = Average U.S. fuel price in year i for steam plant type "g" ($/BTU)

$\overline{EC}^i$ = Average U.S. replacement energy price in year i ($/MWe)

Tables 3.3 and 3.4 present the 1980 base year resource costs, by region, we use in our simulation models for the high and low price scenarios, respectively. Resource costs for any subsequent year are calculated by using the appropriate escalation factor for that resource. Because our subsequent analyses will treat WRC regions 11-17 as one group, we do not feel it is necessary to specify separate cost estimates for each region in this group. The group average is a sum of weighted estimates for each region, the weights reflecting the proportion of the total new capacity for that group to be installed in each separate region.

While use of once-through cooling and the use of wet towers both consume water through evaporation, we do not incorporate water consumption expenditures in our cost simulation models. The difficulty in setting a price for water consumption is that water markets for electric utilities are usually undetermined in areas where once-through cooling has historically been the dominant mode of cooling. Because the ability to use once-through cooling presupposes a large water supply, we expect that a water

Table 3.1 Projected Real Dollar Price Escalation Rates for Select Resources*

	Coal		Gas		Oil		Uranium	
	1975 -2000	1985 -2000	1975 -2000	1985 -2000	1975 -2000	1985 -2000	1975 -2000	1985 -2000
ERRI/SRI (1977)	N.A.	.2%	N.A.	2.3%	N.A.	1.8%	N.A.	.1%
Spencer and Gildersleeve (1978)	.6%	.7%	4.0%	4.0%	2.4%	2.1%	2.4%	2.7%
EPRI/Supply 77 (1978)	.5%	.5%	2.0%	2.0%	1.7%	1.7%	.3%	.3%
Hudson & Jorgenson (1974)	2.6%	2.3%	2.6%	2.6%	.7%	.8%	N.A.	N.A.

*Escalation rates refer to changes in $\$/10^6$ BTU delivered

Table 3.2 Real Dollar Price Escalation Factors Used in this Study

	High Price Scenario	Low Price Scenario
Coal	.5%	0%
Gas	4.0%	2.0%
Oil	2.0%	1.5%
Uranium	2.0%	.4%
Plant (Capital Cost)	1.5%	1.5%
Cooling System (Capital Cost)	0%	0%

Table 3.3 Projected 1980 Component Costs ($1977); High Price Escalation Scenario

Region	Fossil Fuel† ($/MWht)	Nuclear Fuel ($/MWht)	Replacement Energy* ($/MWhe)
1. New England	7.87	1.36	26.77
2. Middle Atlantic	5.09	1.36	28.86
3. S. Atlantic - Gulf	4.68	1.36	27.40
4. Great Lakes	4.32	1.36	29.00
5. Ohio River Basin	3.36	1.36	31.71
6. Tennessee River Basin	2.71	1.36	31.71
7. Upper Mississippi	3.21	1.36	26.12
8. Lower Mississippi	3.21	1.36	11.54
10. Missouri River Basin	2.24	1.36	7.84
11 - 17	3.53	1.36	25.77
18. California	8.94	1.36	28.78

Nuclear Plant: $800/KW
Fossil Plant: $375/KW (oil); $620/KW (coal)
Replacement Turbine: $150/KW

Discount Rate: 4%
Fixed Charge Rate: 11%
Capacity Factor = .75
} inflation free

†Assumes fossil units in Regions 1 and 18 continue to burn oil; fossil units in all other regions burn coal. [See Edison Electric Institute Yearbook (1976); U.S. Dept. of Energy (1978); U.S. Federal Power Commission (1976)]

*Assumes replacement energy in Regions 3 and 10 continues to come primarily from gas combustion turbines; replacement energy in all other regions comes from oil combustion turbines. [See U.S. Federal Power Commission (197)] [Ref. for fuel costs in 1977; U.S. Dept. of Energy, August, 1978].

Table 3.4 Projected 1980 Component Costs ($1977); Low Price Escalation Scenario

Region	Fossil Fuel† ($/MWht)	Nuclear Fuel ($/MWht)	Replacement Energy* ($/MWhe)
1. New England	7.75	1.30	24.95
2. Middle Atlantic	5.02	1.30	26.02
3. St. Atlantic - Gulf	4.61	1.30	24.72
4. Great Lakes	4.26	1.30	26.15
5. Ohio River Basin	3.31	1.30	28.60
6. Tennessee River Basin	2.68	1.30	28.60
7. Upper Mississippi	3.16	1.30	25.74
8. Lower Mississippi	3.16	1.30	10.89
10. Missouri River Basin	2.20	1.30	7.40
11 - 17	3.28	1.30	25.40
18. California	8.81	1.30	28.36

Nuclear Plant: $800/KW
Fossil Plant: $375/KW (oil); $620/KW (coal)
Replacement Turbine: $150/KW

$\left.\begin{array}{l}\text{Discount Rate: } 4\% \\ \text{Fixed Charge Rate: } 11\%\end{array}\right\}$ inflation free
Capacity Factor = .75

†Assumes fossil units in Regions 1 and 18 continue to burn oil; fossil units in all other regions burn coal.

*Assumes replacement energy in Regions 8 and 10 continues to come primarily from gas combustion turbines; replacement energy in all other regions comes from oil combustion turbines.

price set equal to zero at all inland sites is a reasonable approximation for our simulations. The exception to this will occur at coastal sites where nearby freshwater supplies may not be large enough to accomodate the consumptive requirements of freshwater evaporative towers (e.g. along the coast of Southern California)

It is not feasible for us to examine every specific case where local water supplies would be noticeably affected by the additional water demands from closed cycle cooling systems. We offer, instead, projections on the future water consumption as a consequence of thermal regulation, by region, with additional comments regarding locations where we believe the problems of water supply could become critical.

3.5 Simulation Results

Tables 3.5 and 3.6 present our estimates of the unit incremental annual operating costs ($/MWe/year) of closed cycle cooling by region for the high price escalation and the low price escalation scenarios, respectively. These results, which are presented by plant type (fossil and nuclear) apply for representative units that will begin commercial operation in five-year intervals, beginning in 1980, and indicate the annual cost of operating any unit type in select years subsequent to its initial year of operation.

It is observed that the incremental costs applicable to representative fossil units in Region One and Eighteen are substantially greater than the costs expected for fossil units in all other regions. This is due to the fact that we assume new fossil units in Regions One and Eighteen will continue to follow historical fuel consumption patterns and hence use oil rather than coal as the fuel source. This assumption runs counter to national energy policy objectives, which call for a substitution of coal for oil at new fossil units. Thus, if compliance with energy policy objectives requires the new fossil units planned for Regions One and Eighteen to use coal, it will be necessary to revise (downward) our cost estimates for these two regions.

Tables 3.7 and 3.8 present our estimates of the lifetime evaluated present valued incremental costs, by WRC region, for representative fossil and nuclear fueled plants under the high and low price escalation scenarios respectively. These costs apply to units that will begin commercial operation in five year increments, beginning in 1980, and are present valued to the initial date of operation.

Tables 3.9 and 3.10 present our estimates of the relative incremental annual resource costs, by region, associated with the operation of closed cycle cooling systems for reprentative fossil and nuclear steam electric plants, respectively.

Table 3.5 Incremental Annual Operating Cost of Closed Cycle Cooling High Price Escalation Scenario*

Region	Initial Year of Operation	Incremental Operating Cost ($/MW-year) 1980 ΔCost	1985 ΔCost	1990 ΔCost	1995 ΔCost	2000 ΔCost
One Fossil	1980	3070	3240	3440	3650	3890
	1985		3310	3510	3720	3960
	1990			3580	3800	4030
	1995				3880	4120
	2000					4200
One Nuclear	1980	4290	4340	4390	4450	4510
	1985		4590	4640	4700	4760
	1990			4910	4970	5030
	1995				5260	5320
	2000					5840
Two Fossil	1980	2150	2170	2200	2230	2260
	1985		2220	2270	2300	2330
	1990			2350	2370	2400
	1995				2440	2470
	2000					2550
Two Nuclear	1980	4440	4480	4520	4570	4620
	1985		4720	4770	4810	4870
	1990			5030	5080	5130
	1995				5360	5420
	2000					5720

*$1977

Table 3.5 cont. Incremental Annual Operating Cost of Closed Cycle Cooling High Price Escalation Scenario*

Region	Initial Year of Operation	Incremental Operating Cost ($/MW 1980 ΔCost	1985 ΔCost	1990 ΔCost	1995 ΔCost	2000 ΔCost
Three Fossil	1980	2020	2050	2040	3130	2180
	1985		2100	2140	2180	2230
	1990			2180	2230	2270
	1995				2280	2320
	2000					2380
Three Nuclear	1980	3970	4010	4060	4100	4160
	1985		4220	4270	4320	4370
	1990			4500	4550	4600
	1995				4800	4850
	2000					5220
Four Fossil	1980	2470	2500	2530	2560	2590
	1985		2580	2610	2640	2670
	1990			2700	2730	2760
	1995				2830	2860
	2000					2960
Four Nuclear	1980	4560	4600	4650	4690	4750
	1985		4850	4900	4950	5004
	1990			5170	5220	5270
	1995				5510	5560
	2000					5880

*$1977

Table 3.5 cont. Incremental Annual Operating Cost of Closed Cycle Cooling High Price Escalation Scenario*

Region	Initial Year of Operation	Incremental Operating Cost ($/MW-year) 1980 ΔCost	1985 ΔCost	1990 ΔCost	1995 ΔCost	2000 ΔCost
Five Fossil	1980	1860	1880	1900	1920	1940
	1985		1950	1970	1980	2010
	1990			2040	2060	2080
	1995				2140	2150
	2000					2230
Five Nuclear	1980	4430	4470	4510	4550	4600
	1985		4710	4750	4800	4850
	1990			5020	5060	5110
	1995				5350	5400
	2000					5800
Six Fossil	1980	2140	2170	2200	2230	2270
	1985		2390	2410	2440	2460
	1990			2490	2510	2540
	1995				2600	2630
	2000					2710
Six Nuclear	1980	4610	4660	4710	4770	4830
	1985		4910	4960	5020	5080
	1990			5230	5290	5350
	1995				5580	5640
	2000					5950

*$1977

Table 3.5 cont. Incremental Annual Operating Cost of Closed Cycle Cooling High Price Escalation Scenario*

Region	Initial Year of Operation	Incremental Operating Cost ($/MW-year) 1980 ΔCost	1985 ΔCost	1990 ΔCost	1995 ΔCost	2000 ΔCost
Seven Fossil	1980	2020	2040	2060	2080	2100
	1985		2110	2130	2150	2170
	1990			2210	2230	2250
	1995				2310	2330
	2000					2420
Seven Nuclear	1980	4330	4380	4430	4490	4560
	1985		4630	4690	4750	4810
	1990			5160	5200	5260
	1995				5490	5550
	2000					5860
Eight Fossil	1980	1810	1850	1900	1960	2020
	1985		2070	2110	2150	2200
	1990			2170	2210	2260
	1995				2280	2330
	2000					2400
Eight Nuclear	1980	4340	4390	4450	4510	4580
	1985		4620	4680	4740	4810
	1990			4930	5000	5070
	1995				5270	5340
	2000					5740

*$1977

Table 3.5 cont. Incremental Annual Operating Cost of Closed Cycle Cooling High Price Escalation Scenario*

Region	Initial Year of Operation	Incremental Operating Cost ($/MW-year) 1980 ΔCost	1985 ΔCost	1990 ΔCost	1995 ΔCost	2000 ΔCost
Ten Fossil	1980	1670	1680	1700	1720	1750
	1985		1750	1770	1790	1820
	1990			2000	2020	2040
	1995				2100	2120
	2000					2210
Ten Nuclear	1980	4320	4360	4420	4480	4540
	1985		4620	4670	4730	4800
	1990			4940	5000	5060
	1995				5490	5550
	2000					5860
11-17 Fossil	1980	2040	2060	2080	2100	2120
	1985		2130	2150	2170	2190
	1990			2230	2250	2260
	1995				2330	2350
	2000					2440
11-17 Nuclear	1980	4330	4380	4430	4500	4560
	1985		4630	4690	4750	4810
	1990			5160	5200	5260
	1995				5490	5550
	2000					5860

*$1977

Table 3.5 cont. Incremental Annual Operating Cost of Closed Cycle Cooling High Price Escalation Scenario*

Region	Initial Year of Operation	Incremental Operating Cost ($/MW-year) 1980 ΔCost	1985 ΔCost	1990 ΔCost	1995 ΔCost	2000 ΔCost
Eighteen Fossil	1980	3130	3330	3530	3760	4010
	1985		3360	3590	3820	4070
	1990			3660	3890	4140
	1995				3960	4160
	2000					4290
Eighteen Nuclear	1980	4550	4590	4630	4680	4730
	1985		4840	4880	4930	4980
	1990			5150	5200	5250
	1995				5490	5540
	2000					5860

*$1977

Table 3.6 Incremental Annual Operating Cost of Closed Cycle Cooling
Low Price Escalation Scenario*

Region	Initial Year of Operation	Incremental Operating Cost ($/MW-year) 1980 ΔCost	1985 ΔCost	1990 ΔCost	1995 ΔCost	2000 ΔCost
One Fossil	1980	3040	3170	3310	3460	3620
	1985		3240	3380	3530	3700
	1990			3450	3600	3760
	1995				3690	3850
	2000					3930
One Nuclear	1980	4270	4280	4290	4300	4310
	1985		4530	4540	4550	4560
	1990			4810	4820	4830
	1995				5110	5120
	2000					5430
Two Fossil	1980	2130	2140	2140	2150	2150
	1985		2200	2210	2210	2220
	1990			2280	2280	2290
	1995				2360	2360
	2000					2440
Two Nuclear	1980	4220	4230	4240	4250	4260
	1985		4480	4490	4500	4510
	1990			4750	4760	4770
	1995				5050	5060
	2000					5360

*$1977

Table 3.6 cont. Incremental Annual Operating Cost of Closed Cycle Cooling
Low Price Escalation Scenario*

Region	Initial Year of Operation	Incremental Operating Cost ($/MW-year) 1980 ΔCost	1985 ΔCost	1990 ΔCost	1995 ΔCost	2000 ΔCost
Three Fossil	1980	1990	2000	2020	2040	2050
	1985		2050	2060	2080	2100
	1990			2110	2130	2150
	1995				2180	2200
	2000					2250
Three Nuclear	1980	3950	3960	3970	3980	3980
	1985		4170	4180	4190	4200
	1990			4410	4420	4430
	1995				4670	4680
	2000					4940
Four Fossil	1980	2450	2460	2460	2470	2470
	1985		2540	2540	2550	2550
	1990			2630	2640	2640
	1995				2740	2740
	2000					2840
Four Nuclear	1980	4340	4350	4360	4370	4380
	1985		4600	4610	4620	4630
	1990			4880	4890	4900
	1995				5190	5200
	2000					5510

*$1977

Table 3.6 cont. Incremental Annual Operating Cost of Closed Cycle Cooling
Low Price Escalation Scenario*

Region	Initial Year of Operation	Incremental Operating Cost ($/MW-year) 1980 ΔCost	1985 ΔCost	1990 ΔCost	1995 ΔCost	2000 ΔCost
Five Fossil	1980	1850	1850	1860	1860	1870
	1985		1920	1920	1930	1930
	1990			1990	2000	2000
	1995				2070	2080
	2000					2160
Five Nuclear	1980	4200	4210	4220	4230	4240
	1985		4450	4460	4480	4480
	1990			4730	4740	4750
	1995				5030	5030
	2000					5340
Six Fossil	1980	2120	2130	2140	2150	2170
	1985		2200	2210	2220	2240
	1990			2290	2300	2310
	1995				2380	2400
	2000					2630
Six Nuclear	1980	4590	4600	4610	4620	4630
	1985		4850	4860	4870	4880
	1990			5130	5140	5150
	1995				5430	5440
	2000					5750

*$1977

Table 3.6 cont. Incremental Annual Operating Cost of Closed Cycle Cooling Low Price Escalation Scenario*

Region	Initial Year of Operation	Incremental Operating Cost ($/MW-year) 1980 ΔCost	1985 ΔCost	1990 ΔCost	1995 ΔCost	2000 ΔCost
Seven Fossil	1980	2020	2020	2020	2030	2030
	1985		2090	2090	2100	2100
	1990			2170	2170	2180
	1995				2260	2260
	2000					2350
Seven Nuclear	1980	4310	4320	4330	4340	4350
	1985		4570	4580	4590	4600
	1990			4850	4860	4870
	1995				5150	5160
	2000					5480
Eight Fossil	1980	1790	1800	1820	1840	1850
	1985		1860	1870	1890	1910
	1990			1930	1960	1970
	1995				2010	2030
	2000					2100
Eight Nuclear	1980	4320	4320	4340	4350	4360
	1985		4560	4570	4580	4590
	1990			4820	4830	4840
	1995				5110	5120
	2000					5410

*$1977

Table 3.6 cont. Incremental Annual Operating Cost of Closed Cycle Cooling Low Price Escalation Scenario*

Region	Initial Year of Operation	Incremental Operating Cost ($/MW-year) 1980 ΔCost	1985 ΔCost	1990 ΔCost	1995 ΔCost	2000 ΔCost
Ten Fossil	1980	1660	1660	1660	1670	1670
	1985		1730	1730	1740	1740
	1990			1812	1820	1820
	1995				1900	1960
	2000					2000
Ten Nuclear	1980	4300	4300	4310	4320	4330
	1985		4560	4570	4580	4590
	1990			4830	4840	4850
	1995				5140	5140
	2000					5460
11-17 Fossil	1980	2030	2030	2040	2040	2050
	1985		2120	2130	2130	2140
	1990			2220	2230	2230
	1995				2330	2330
	2000					2450
11-17 Nuclear	1980	4310	4320	4330	4340	4350
	1985		4570	4580	4590	4600
	1990			4850	4860	4870
	1995				5150	5160
	2000					5470

*$1977

Table 3.6 cont. Incremental Annual Operating Cost of Closed Cycle Coöling Low Price Escalation Scenario*

Region	Initial Year of Operation	Incremental Operating Cost ($/MW-year) 1980 ΔCost	1985 ΔCost	1990 ΔCost	1995 ΔCost	2000 ΔCost
Eighteen Fossil	1980	3110	3240	3400	3550	3730
	1985		3300	3460	3620	3790
	1990			3520	3680	3850
	1995				3760	3930
	2000					4000
Eighteen Nuclear	1980	4330	4340	4350	4360	4370
	1985		4590	4600	4610	4620
	1990			4870	4880	4890
	1995				5170	5180
	2000					5490

*$1977

Table 3.7 Incremental Present Valued Cost of Closed Cycle Cooling*
High Price Escalation Scenario

Region	Plant Type	Initial Year of Operation ($/MW) 1980	1985	1990	1995	2000
One	Fossil	80,400	86,900	93,900	101,900	110,200
One	Nuclear	106,100	111,900	118,200	125,000	132,300
Two	Fossil	46,000	47,600	50,000	52,300	54,700
Two	Nuclear	109,400	115,200	121,300	128,000	135,200
Three	Fossil	37,800	39,300	40,900	42,700	44,500
Three	Nuclear	98,000	103,200	108,800	114,900	121,400
Four	Fossil	52,800	55,200	57,700	60,500	63,200
Four	Nuclear	112,500	118,400	124,700	131,600	139,100
Five	Fossil	41,400	43,300	45,300	47,500	49,700
Five	Nuclear	109,100	114,800	120,900	127,600	134,800
Six	Fossil	42,900	47,900	50,000	52,100	54,400
Six	Nuclear	113,900	120,000	126,400	133,500	141,200
Seven	Fossil	45,900	47,900	50,200	52,500	54,900
Seven	Nuclear	107,100	113,100	119,100	125,800	132,900
Eight	Fossil	47,400	54,400	57,000	59,800	62,900
Eight	Nuclear	107,300	113,200	119,500	126,400	133,700
Ten	Fossil	37,000	38,900	44,400	46,700	49,100
Ten	Nuclear	106,700	112,600	119,000	125,600	132,800
Eleven-	Fossil	46,400	48,400	50,600	52,900	55,400
Seventeen	Nuclear	107,100	113,100	119,100	125,800	132,900
Eighteen	Fossil	81,500	87,400	95,100	103,000	111,500
Eighteen	Nuclear	112,100	118,000	124,300	131,100	138,500

*Evaluated in 1977 dollars at the year of initial operation assuming a 40 year lifetime and an inflation free discount rate of 4%.

Table 3.8 Incremental Present Valued Cost of Closed Cycle Cooling*
Low Price Escalation Scenario

Region	Plant Type	Initial Year of Operation ($/MW)				
		1980	1985	1990	1995	2000
One	Fossil	75,600	80,400	85,400	90,900	96,800
One	Nuclear	102,800	107,600	112,700	118,200	124,100
Two	Fossil	45,300	46,600	48,100	49,700	51,300
Two	Nuclear	106,200	111,100	116,300	121,900	127,900
Three	Fossil	36,000	37,100	38,300	39,600	41,000
Three	Nuclear	95,100	99,300	103,900	108,800	114,000
Four	Fossil	52,400	54,000	55,800	57,700	59,700
Four	Nuclear	109,100	114,100	119,400	125,200	131,400
Five	Fossil	40,100	41,400	42,800	44,000	46,100
Five	Nuclear	105,700	110,600	115,800	121,400	127,500
Six	Fossil	41,300	42,800	44,400	46,100	47,900
Six	Nuclear	110,600	115,500	120,800	126,600	132,700
Seven	Fossil	44,700	46,200	47,800	49,600	51,500
Seven	Nuclear	103,600	108,400	113,600	119,100	125,100
Eight	Fossil	44,200	45,800	47,600	49,600	51,600
Eight	Nuclear	103,600	108,200	113,200	118,600	124,300
Ten	Fossil	35,700	37,000	38,500	40,000	41,800
Ten	Nuclear	103,100	107,900	113,300	118,500	124,500
Eleven-	Fossil	45,100	46,600	48,200	50,000	51,900
Seventeen	Nuclear	103,600	108,400	113,600	119,100	125,000
Eighteen	Fossil	76,500	81,200	86,400	92,000	97,900
Eighteen	Nuclear	108,800	113,800	119,100	124,800	131,000

*Evaluated in 1977 dollars at the year of initial operation assuming a 40 year lifetime and an inflation free discount rate of 4%

Table 3.9 Relative Incremental Annual Resource Costs Associated with Closed Cycle Cooling for Fossil Plants

Region	Annual Cost % over O-T	Annual Energy Loss (10^6 BTU/MWe)	% over O-T	Annual Water Loss (acre-feet/MWe)	% over O-T †
One	1.7%	720	1.3%	3.2	43%
Two	1.5%	520	1.0%	3.3	43%
Three	1.5%	410	.8%	3.6	43%
Four	2.0%	690	1.3%	3.2	43%
Five	1.7%	520	1.0%	3.3	43%
Six	2.2%	650	1.2%	3.4	43%
Seven	1.9%	550	1.0%	3.2	43%
Eight	1.7%	540	1.0%	3.6	43%
Ten	1.8%	620	1.2%	3.2	43%
11-17	1.8%	550	1.0%	3.2	43%
Eighteen	1.6%	680	1.2%	3.4	43%

†Assumes evaporation from once-through cooling systems is 71% that of mechanical draft evaporative towers.

Table 3.10 Relative Incremental Annual Resource Costs Associated with Closed Cycle Cooling for Nuclear Plants

WRC Region	Annual Cost % over O-T	Annual Energy Loss (10^6 BTU/MWe)	% over O-T	Annual Water Loss (acre-feet/MWe)	% over O-T †
One	3.8%	1080	1.6%	4.7	43%
Two	3.9%	930	1.4%	4.8	43%
Three	3.5%	960	1.4%	5.3	43%
Four	4.0%	970	1.4%	4.7	43%
Five	3.9%	900	1.3%	4.8	43%
Six	4.1%	1100	1.6%	5.0	43%
Seven	3.8%	1130	1.7%	4.7	43%
Eight	3.8%	1170	1.7%	5.2	43%
Ten	3.8%	1130	1.7%	4.7	43%
11-12	3.8%	1130	1.7%	4.7	43%
Eighteen	4.0%	940	1.4%	5.0	43%

†Assumes evaporation from once-through cooling systems is 70% that of mechanical draft evaporative towers.

IV COMPARISON OF COSTS AND RESOURCE CONSUMPTION BETWEEN OPEN AND CLOSED CYCLE COOLING SYSTEMS: REGIONAL AND NATIONAL LEVEL

4.1 Introduction

With the assumption that without thermal controls new plants could locate on water bodies in the patterns described by Alternative Siting Pattern #1 (Chapter 2), our cost estimates display greater sensitivity to our energy demand forecasts than to our price escalation forecasts. The number of megawatts of new capacity which we estimate will be affected by thermal standards under the high energy demand scenario is roughly 60% higher than the capacity similarly affected under the low energy demand scenario. (Tables 2.3 and 2.4, Chapter II). In contrast, the estimated unit incremental year 2000 annual operating costs under the high price escalation scenario are only 6% higher then the corresponding costs under the low price escalation scenario. This greater sensitivity to demand forecasts is in part due to the method with which new plants are located on water bodies with the siting pattern #1. If we were to use any of the alternative potential siting patterns described in Chapter Two we would continue to find that overall costs are more sensitive to electric demand projections than to price escalation projection although the relative difference in costs between the low and the high energy demand projections would be reduced to approximately 14% - 23%. Because our cost estimates will show a greater sensitivity to demand projections than to price projections, we will henceforth consider only one price escalation scenario - the high one - for future discussion.

4.2 Comparison of Cost and Resource Consumption

Tables 4.1 and 4.2 present our estimates of the overall annual costs, by region, of complying with current thermal regulations in select years between 1980 and 2000, for the high and low energy demand scenarios respectively. The annual cost in any year is the product of the unit incremental closed cycle cooling costs summarized in Tables 3.6 through 3.10 and the number of megawatts we expect will operate with closed cycle cooling for environmental purposes by that year (Tables 2.6 & 2.7)

While Tables 4.1 and 4.2 present our estimates of incremental annual costs of thermal pollution control for select years, we can fit a function through these points to derive estimated annual costs in any year. For the national incremental annual costs we found the following functions fit well:

$$NAC^{i} = 52.8\ (i - 1974)^{1.20} \quad (\$10^{6}) \text{ (high energy demand)}$$

$$NAC^{i} = 32.9\ (i - 1974)^{1.20} \quad (\$10^{6}) \text{ (low energy demand)}$$

where

$$NAC^{i} = \text{national incremental annual cost in year } i\ (\$)$$

We can determine the cumulative annual costs of thermal controls from 1975 to 2000 by summing the values of NAC^{i} for the years i between 1975 and 2000. The cumulative national incremental costs can be expected to be in the range of \$20.4 billion (for the low energy demand scenario) and \$32.8 billion (for the high energy demand scenario). These values are expressed in 1977 dollars.

Tables 4.3 presents our estimates of the additional annual fuel

Table 4.1 Expected Annual Cost of Current Thermal Regulations by Region (High Energy Demand)†

Water Resource Council Region	Year 1980	1985	1990	1995	2000
One	23.4	49.1	77.5	108.4	143.3
Two	49.4	102.0	158.6	219.2	284.2
Three	33.0	68.0	105.9	146.6	190.9
Four	77.8	161.0	250.2	345.5	447.7
Five	67.5	139.5	216.7	299.1	387.5
Six	16.6	34.8	54.2	74.9	97.3
Seven	67.4	139.9	219.4	306.8	399.5
Eight	32.6	68.2	106.7	148.0	193.5
Ten	20.9	43.3	68.1	95.4	124.6
11-17	54.4	112.9	177.5	248.9	324.6
Eighteen	13.7	28.6	45.0	62.9	82.4
National	456.7	947.5	1479.8	2055.7	2675.5

† x 10^6 \$1977; High price escalation scenario

Table 4.2 Expected Annual Cost of Current Thermal Regulations by Region (Low Energy Demand)†

Water Resource Council Region	1980	1985	Year 1990	1995	2000
One	14.3	30.1	47.5	66.4	87.8
Two	28.7	59.4	92.3	127.6	165.4
Three	20.3	42.2	65.7	90.6	118.0
Four	49.8	103.0	160.1	221.1	286.5
Five	39.8	82.2	127.7	176.2	228.3
Six	9.6	19.9	31.0	43.0	55.8
Seven	41.7	88.5	139.1	194.3	253.1
Eight	20.1	41.9	65.5	91.0	119.0
Ten	13.4	27.7	43.6	61.1	79.8
11-17	33.1	68.7	108.0	151.4	197.4
Eighteen	13.1	27.3	42.9	59.8	78.5
National	283.9	590.9	923.4	1282.5	1669.6

† x 10^6 \$1977; High price escalation scenario

consumption in the year 2000 as a consequence of thermal pollution controls for our high and low energy demand scenarios. Assuming a linear distribution of new capacity additions between the years 1975 and 2000, we estimate the cumulative energy loss in this twenty-five year interval can range from 0.73 Billion barrels oil equivalent for the low energy demand scenario to 1.16 Billion Barrels oil equivalent for the high energy demand scenario.[1]

Our estimates of the additional freshwater consumption due to environmental controls are sensitive to the way in which we evaluate the freshwater loss from closed cycle plants that would otherwise operate with once-through cooling at coastal sites without controls. Such plants may either install saltwater towers-in which case no additional freshwater consumption occurs-or install freshwater towers-in which case the additional freshwater consumption is equal to the total water evaporation from towers. Table 4.4 presents our estimates regarding the additional fresh water consumption in the year 2000 for the low and the high energy demand scenarios, respectively, assuming that all closed-cycle cooling is with freshwater evaporative towers. Table 4.5 presents similar estimates for the low and the high energy demand scenarios assuming that all closed cycle cooling on coastal sites is with saltwater evaporative towers. If all closed cycle cooling is with freshwater towers we expect the additional freshwater consumption in the year 2000 will range from 2,320,000 acre feet to 3,420,000 acre feet for the low and the high energy demand scenarios, respectively. With closed cycle cooling on coastal

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[1]Assumes one barrel of oil represents 6×10^6 BTU.

Table 4.3 Incremental Fuel Consumption in the Year 2000 Due to Thermal Controls

Region	High Energy Demand (10^6 Barrels oil equivalent)[1]	Low Energy Demand (10^6 Barrels oil equivalent)[1]
One	4.8	3.0
Two	8.9	5.2
Three	6.4	4.0
Four	14.9	9.6
Five	12.7	7.5
Six	3.4	2.0
Seven	14.9	9.4
Eight	7.5	4.6
Ten	5.3	3.4
11-17	11.9	7.3
Eighteen	2.4	2.3
Total US	93.1	58.3
Total US 1975-2000	1,160.0	730.0

[1]Assuming 6×10^6 BTU/Barrel of oil

Table 4.4 Incremental Freshwater Consumption in the Year 2000 without the Installation of Salt-Water Towers at Coastal Sites

Region	High Energy Demand (10^3 acre-feet/year)	Low Energy Demand (10^3 acre-feet/year)
One	290	180
Two	760	430
Three	250	140
Four	420	270
Five	420	250
Six	90	50
Seven	410	250
Eight	210	130
Ten	140	90
11-17	480	290
Eighteen	250	240
Total US	3,420	2,320

Table 4.5 Incremental Freshwater Consumption in the Year 2000 with the Installation of Salt-Water Towers at Coastal Sites

Region	High Energy Demand (10^3 acre-feet/year)	Low Energy Demand (10^3 acre-feet/year)
One	50	30
Two	60	30
Three	230	140
Four	420	270
Five	420	250
Six	90	50
Seven	410	250
Eight	210	130
Ten	140	90
11-17	220	130
Eighteen	0	0
Total US	2,250	1,370

sites using saltwater evaporative towers, we expect the additional freshwater consumption in the year 2000 will range from 1,370,000 acre-feet to 2,250,000 acre-feet for the low and the high energy demand scenarios, respectively.

4.3 Discussion of Total Costs

Dollar Costs

Our estimates for the incremental dollar costs of complying with current thermal regulations may be put in perspective by comparing these values with several other measurements for the steam electric industry: total cost of operation, potential revenues and potential profits, and costs for other environmental controls. We estimate that under our high price escalation scenario the sum of annualized capital costs, fuel costs and replacement energy costs between 1975 and 2000 for all new capacity will range from $1640 billion to $2620 billion (in $1977) for the low and the high energy demand scenarios, respectively.[1] Therefore, the corresponding dollar costs of thermal controls, $20.4 billion and $32.8 billion for the low and the high energy demand scenarios respectively, represent approximately 1.3% of the expected costs of operating new capacity.

In 1977 the average unit revenue per Kwh for investor owned electric utilities (which represented 76% of the commercial electric output in 1977) in $1977, was roughly $.034/Kwh (Edison Electric Institute,

[1] We assume roughly 54% of the new electric capacity planned for the years 1975 to 2000 could be installed with once-through cooling without thermal controls (Chapter II, Alternative Siting Patterns #1). We assume new capacity additions will be constant each year, with new additions to the year 2000 equal to 937,000 MWe under the low energy demand scenario and 1,504,000 MWe under the high energy demand scenario.

1978). Under our high price escalation scenario the average cost of generating electricity will escalate (in real dollars) by roughly .8% per year. If unit revenues escalate at the same rate, then we estimate the cumulative revenues accruing to all new capacity between 1975 and 2000 ($1977) will be between $3090 billion and $4950 billion for the low and the high energy demand scenarios, respectively. Therefore the corresponding dollar costs of thermal controls will represent approximately 0.7% of the expected revenues accruing to all new electric capacity.

For the years 1970 to 1977 the net income (revenues minus the sum of operating costs, debt charges and taxes) per Kwh for investor owned utilities remained at an almost constant $0.0045/Kwh in 1977 dollars (Edison Electric Institute, 1978) (This consistency is partially explained by the fact that profit levels for the industry are regulated by government agencies.) Assuming this constant dollar return is maintained from 1975 to 2000, the cumulative net income accruing to new generating capatiy for that period will be between $351 billion and $561 billion for the low and the high energy demand scenarios, respectively ($1977). Therefore the costs of thermal controls will represent roughly 5.8% of the net income accruing to new generation capacity.

Finally, we offer a very rough comparison between the expected costs of thermal pollution controls and the costs of flue-gas desulferization controls for coal-fired plants. Jahnig and Shaw (1978) estimate that flue gas desulferization increases coal plant operating costs by $0.0059/Kwh. These investigators also suggest that 37% of all new coal fired plants built between 1978 and 1986 will require flue gas desulferization to meet air quality standards. For our rough comparison we will assume

1) that desulferization costs, in real dollars, remain constant at 5.9 mills/Kwh for the interval 1975 - 2000, and 2) that 37% of all new coal fired plants built between 1975 and 2000 will require desulferization. Our high energy demand scenario suggests roughtly 200,000 MW of coal fired capacity will be built between 1975 and 2000. Assuming that this new capacity is distributed linearly over time and that it operates at a 75% capacity factor, the total estimated cost of meeting clean air standards between the years 1975 and 2000 is:

$$\tfrac{1}{2}(25 \text{ years} * 200{,}000 \text{ MW} * 8760 \text{ hr/yr} * .75 * 5.9 \text{ \$/MWH}) = \$100 \text{ Billion}$$

Thus, the estimated costs attributed to these air quality standards is roughly 3 times the estimated cost of current thermal pollution regulations ($32.8 billion for the high energy demand scenario). It should be noted that in the event we have underestimated the actual percentage of new generating capacity going to fossil fired plants, our thermal pollution control cost estimates will be too high and our air pollution control cost estimates will be too low.

Fuel Consumption

The magnitude of the energy losses induced by closed cycle cooling may be perceived by comparing these losses with projected energy commitments elsewhere in the economy. We estimate the annual energy loss from thermal controls for the high energy demand scenario will be roughly 5.5×10^{14} BTU/year in the year 2000. In contrast, under the high demand scenario, the projected national energy consumption in the year 2000 will be 163×10^{15} BTU/year and the projected electric utility fuel consumption will be roughly 91 x 10^{15} BTU/year (WRC, Appendix H, 1977). Thus, energy losses due by thermal controls will represent approximately .3% of the nation's energy consumption and .6% of the electric utility's energy consumption.

Another useful comparison can be made with respect to the amount of energy that could be saved if greater efficiencies in the steam cycle energy conversion process were realized through new technologies. ERDA (1975) estimated a maximum likely savings of 2.5 x 10^{15} BTU/year would be realized by the year 2000, under a 160 quad energy consumption scenario, if new technologies such as superconducting generators and Brayton gas turbines, could be made economically feasible. At .55 x 10^{15} BTU/year, the energy loss due to thermal controls under the high energy demand scenario represents approximately 22% of the energy that could be saved if moderate emphasis were placed on improving the electric conversion process of steam electric power plants.

Water Consumption

To place our estimates of incremental water consumption due to thermal controls in perspective, we compare these estimates with a) the expected <u>growth</u> between 1975 and 2000 in non-agricultural water demands for each WRC region and b) the total non-agricultural water demand projected for each region in the year 2000. While agricultural water use is often the dominant use in every region, agricultural water demands are spread over large land areas and may not disrupt local supplies to the extent non-agricultural uses do. Thus, agricultural water use is not compared here. For regions where recovereable water may be in short supply the first comparison (i.e. with growth in water demand) provides some idea of the extent to which water demands due to thermal controls will compete with all other new users while the latter comparison (i.e. with total demand) suggests the extent to which thermal control induced water demands will compete will all non-agricultural uers. These comparisons are presented in Table 4.6. In addition this table indicates how large these induced demands are relative to the single largest growth in demand from any sector, excluding the agricultural sector and the steam electric utility industry.

The figures in Table 4.6 refer to the high energy demand scenario because both the projections for new regional freshwater demand and the high energy demand scenario itself were developed simultaneously by the U.S. Water Resources Council for its Second National Water Resources Assessment (1978). Consequently, because these water use projections may imply a higher level of future economic activity then is anticipated with the low energy demand scenario, we feel it would be misleading to compare the thermal control induced water demands under the low energy demand scenario with the projections for new regional water demand found in the WRC assessment.

From Table 4.6, we conclude that thermal control induced fresh water demands will represent a substantial fraction of the new fresh water demand in a number of regions (e.g. WRC Regions One, Two, Seven and Eighteen), and in some regions will approach or exceed the level of new demand from the largest non agricultural/electric utility sector (e.g. Regions One, Two, Four, Seven, Ten, and Eighteen).

One final examination of the impact of thermal controls on water

Table 4.6 Impact of Thermal Control Induced Freshwater Demands[1] in Relation to Regional Freshwater Demands (High Energy Demand Scenario)

Region	% of New Consumptive Demand (1975-2000) (FWT)	% of Year 2000 Demand (FWT)	% of New Consumptive Demand (1975-2000) (SWT)	% of Year 2000 Demand (SWT)	% of Largest New Sector Demand† (1975-2000) (FWT)	(SWT)
One	45%	26%	8%	4%	70%	12%
Two	44%	22%	3%	2%	90%	7%
Three	5%	4%	5%	4%	12%	11%
Four	19%	9%	19%	9%	64%	64%
Five	15%	9%	15%	9%	40%	40%
Six	10%	8%	10%	8%	22%	22%
Seven	28%	18%	28%	18%	136%	136%
Eight	15%	9%	15%	9%	25%	25%
Ten	15%	8%	15%	8%	117%	117%
11-17						
Eighteen	22%	7%	0%	0%	62%	0%

FWT Without salt water towers at coastal sites
SWT With salt water towers at coastal sites

[1] Reference for regional freshwater demands between 1975 and 2000: U.S. Water Resources Council Part V, 1978.

† Generally, manufacturing, with the exception of Region Eighteen where the single largest growth in demand will be from domestic use.

use is to compare these induced water demands with the expected increase in freshwater imports for select areas. One suspects that if a region plans to increase its water imports it does so because projected water demands are expected to exceed available supplies. It is in those regions where additional water losses due to thermal controls will have the greatest impact. While there are likely to be a number of regions where future imports of water will be necessary to meet anticipated demands, there are three subareas where plans for additional imports have been approved (WRC subareas 103, 1805 and 1806). Table 4.7 compares the quantities of additional planned imports with projected incremental water consumption due to thermal controls for these subareas. In subarea 103 (Boston-Providence metropolitan areas) either imports will have to double over planned amounts if current thermal controls are maintained (or if salt water cooling towers are infeasible) or new plants will be required to locate farther from their primary points of demand. Subareas 1805 and 1806 are located wholly within the state of California where current water policies effectively prohibit the use of inland freshwater for power plant cooling (Hendrickson, 1978). Therefore, if current thermal controls are maintained then it is quite likely that new plants will either have to install salt/brackish water towers, pay additional charges to treat municipal waste water for cooling purposes, or seek sites outside the state.

Table 4.7 Comparison of Thermal Control Induced Freshwater Requirements with New Freshwater Imports Authorized for the Period 1975-2000

Aggregated Sub-Area	New Imports (10^3 acre-feet/year)	Incremental Water Loss (10^3 acre-feet/year)	% of New Imports
103	160	190	120%
1805	150	30	20%
1806	920	180	20%

[1]Ref. U.S. Water Resources Council National Assessment, Appendix 2, Part 1, 1978.

V SUMMARY AND CONCLUSIONS

5.1 Introduction

The objectives of this chapter are two-fold: first, we shall present a summary of our results estimating the dollar and resource costs of complying with current thermal regulations; second, we shall set forth a number of suggestions and caveats which we feel will aid decision makers in drawing policy conclusions from this study.

5.2 Fuel Consumption as a Consequence of Controls

From the point of view of national energy conservation, it does not appear than an overall relaxation of current thermal standards will save appreciable amounts of energy. We expect that thermal controls will increase overall U.S. energy consumption by 0.3% and increase overall energy consumption from new steam electric power plants by 0.6% by the year 2000. However, the crucial factor in terms of additional energy consumption due to thermal controls may not be the additional average annual energy loss, but may, instead, be the incremental peak energy loss suffered during the summer months. The concern here is that with closed cycle cooling systems incurring peak losses of between 2-5% plant capacity, a utility system having very low reserve capacity margins and having historically relied on once-through cooling for the majority of its cooling needs could suffer from a weakened reliability of system operations during the summer months. Under such circumstances, the utility would, in all likelihood, be forced to pay a higher price for replacement energy than was assumed in this study. Thus, while it does not appear the current thermal regulations will appreciably increase national energy consumption, we do recommend that these regulations offer some flexibility in compliance for those utility systems that can demonstrate system reliability will be seriously impaired by too rapid a switch from open to closed cycle cooling.

5.3 Dollar Costs of Thermal Controls

For the combination of energy demand, price escalation and new plant siting patterns we have examined, it appears that the costs of thermal controls are a small percentage of potential "at site" operating costs and utility revenues. It was shown earlier in Tables 3.9 and 3.10, in Chapter 3, that incremental closed cycle cooling system costs are approximately 2% and 4% of the "at site" operating costs for fossil and nuclear plants, respectively. Because "at site" operating costs make up only a fraction of the total electricity costs borne by consumers, we conclude that current thermal controls will increase the cost of electricity to consumers by no more than 2-4% in those areas that have historically had a high percentage of plants cooled by once-through cooling. Those WRC Regions falling into this category are likely to be regions One, Four, Five, Seven, Eight and Eighteen. Consumers can expect thermal control induced rate increases substantially less than 2-4% over current levels in regions Two, Three, Six, Ten, Eleven, Twelve and Seventeen, where the potential for continued once-through cooling development would remain small in the absence of thermal controls.

Thermal control costs could threaten the profitability of certain utilities if rate setting agencies refuse to allow thermal control costs to be passed on to consumers. Without rate increases, utilities that would be able to install once-through cooling at all new plants in the absence of thermal controls would lose between 14-18% of their after-tax profits as a consequence of the current thermal regulations. Of course, the smaller the potential for installing once-through cooling at new plants in the absence of thermal controls, the smaller the loss on after-tax profits.

Because we do not incorporate a price for water consumed in our models, it is possible that we have underestimated the costs for closed cycle cooling in areas where freshwater is in short supply. Of course, at inland sites, the ability to install once-through cooling presupposes a large freshwater supply. However, there do exist sites along some coasts where ocean once-through cooling could be installed in the absence of thermal controls even though local freshwater supplies are insufficient for inland freshwater once-through cooling. At these locations, the available freshwater supply may be so scarce that such water does have a price (equal to at least the cost of delivery) and it is possible this price may be too high to be ignored.

5.4 Water Consumption as a Consequence of Controls

Nationally, the additional water consumption due to thermal controls will account for between 10% and 14% of the projected growth in non-agricultural water use between 1975 and 2000 (WRC, Part III, 1978). In comparison, overall consumption from the steam electric power industry will represent the leading sector in new demands for water, accounting for roughly 42% of the growth in non-agricultural water consumption. Induced consumption due to thermal controls is approximately one-third of the growth in consumption for the manufacturing sector and for the steam electric industry. It is roughly equal to the growth in water consumption for domestic, commercial and mineral uses combined.

Although water consumption due to thermal controls may not pose serious consequences for most regions of the U.S., we have noted earlier that some regions, particularly coastal areas, may not have sufficient readily available freshwater supplies to accommodate this new demand. Regardless of whether utilities in these regions purchase freshwater, install salt/brackish water closed cycle cooling systems or locate elsewhere, each one of these options will involve substantial expenditures which are not incorporated in our cost estimates. Consequently, we feel that any further assessments of the impacts of water consumption due to thermal controls should be performed specifically for those select regions where a priori evidence suggests freshwater supplies may be scarce.

5.5 Concluding Remarks

It is important to note that the preceding discussion refers to percentage comparisons, which will remain more or less unchanged regardless of the actual growths realized in electrical generation and economic activity. Thus, at the bottom line, the conclusions offered in this chapter are only marginally related to the demand scenarios we have examined in this report.

We conclude that on the national level the overall consequences of thermal pollution control for new steam electric plants appear to be small compared with the magnitudes of dollar expenditures and resource commitments found for those systems within the steam electric industry that will be most heavily affected by current thermal regulations. However, this assessment should not be interpreted as a justification for current levels of thermal controls. Whether the current level of thermal controls can be justified depends on both the magnitude of the improvement of overall environmental quality realized as a consequence of current standards and the relative value with which society measures an improvement in environmental quality versus an increase in resource commitments.

While we have not examined the potential environmental improvements that can be realized under existing thermal regulations, we can postulate how new once-through cooling development could be distributed among water bodies, classified according to size, without controls. Figure 5.1 illustrates the distribution, by water body type, of the new capacity we feel could install once-through cooling in the absence of thermal controls, over and above the once-through development that has been projected under current controls for the contiguous United States under the high energy demand scenario. Table 5.1 presents this information by Water Resource Council Region. To the extent that large water bodies are able to assimilate a given heat input with a lower resultant temperature rise above ambient than small water bodies, Table 5.1 indicates the regions where some relaxation in current standards may be acceptable. At the very least, these distributions may aid regional and state environmental agencies in determining for what types of water bodies (e.g., lake, ocean, large river, etc.) further research on the effects of heat stress on aquatic ecosystems would be most pertinent.

We do not see a need for continuing studies to assess the costs and resource commitments of thermal control at the national level. In addition, we doubt there are substantial gains to be found in continuing cost-assessment studies of this sort at the regional level for most regions. We recognize that many regional factors have been ignored or understated in this study, but we feel that in order to justify a further study to reassess the costs in any region, evidence should be presented indicating that these factors in fact represent greater costs than those we have presented here. The consequences of induced water consumption may be worth examining, although, as we have noted earlier, substantial consequences are likely to be found only along coastal regions where a shift from coastal once-through cooling to closed-cycle cooling may lead to either massive increases in freshwater consumption or to additional costs not accounted for in this study. In the same vein, the consequences of lower operational reliability during summer months as well as the impact of reduced rates of return on investment could justify further investigations, not at the regional level, but for those individual utility systems that will appear to be most adversely affected by the current thermal regulations.

Figure 5.1 Distribution of Potential Once-Through Cooling Development by Water Body Size over Currently Projected Development by the year 2000.

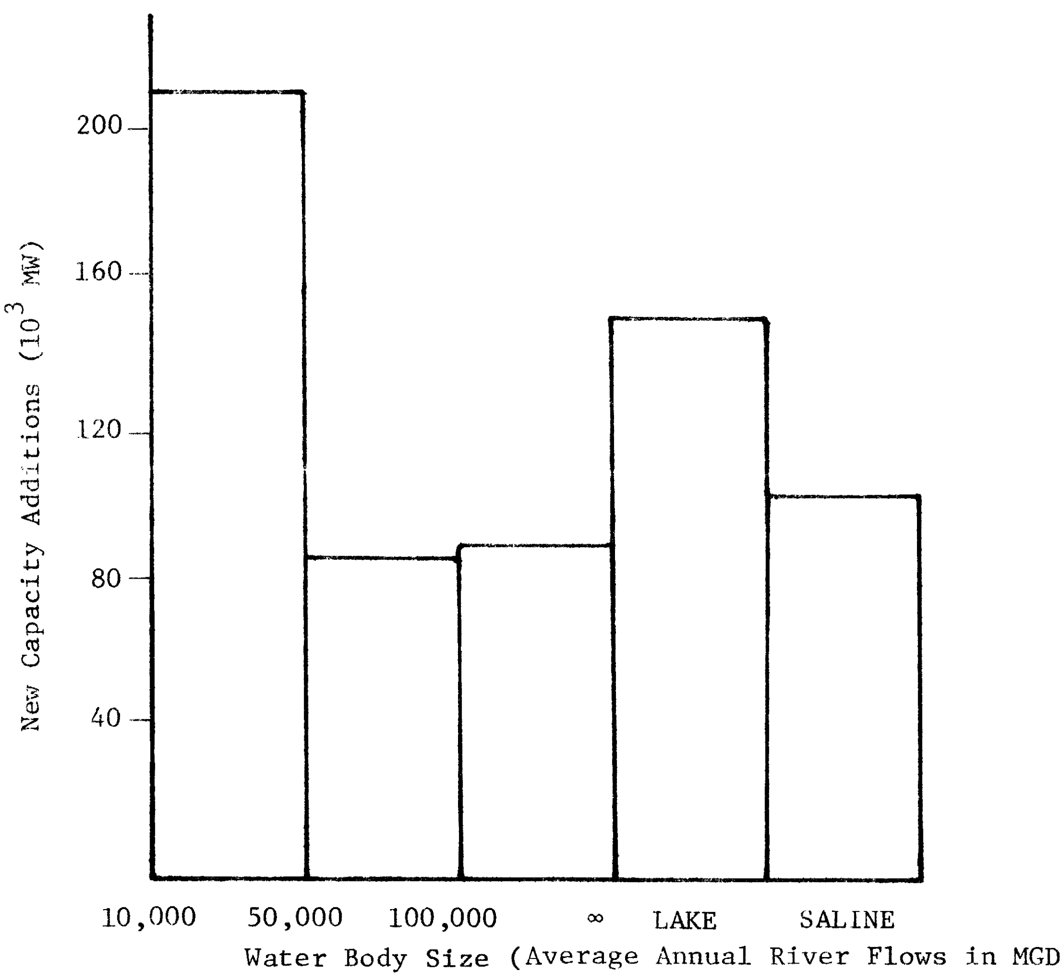

Table 5.1 Distribution of Potential Once-Through Cooling Development by Water Body Size Over Currently Projected Development

Region	Capacity* (MWe)	Water Body Size Rivers (Average Flow)+ 10,000-50,000	50,000-99,999	100,000-∞	Lakes	Saline
One	30,370	41%	0%	0%	0%	59%
Two	66,560	23%	0%	0%	0%	77%
Three	50,830	31%	0%	0%	66%	3%
Four	102,390	0%	0%	11%	89%	0%
Five	105,850	35%	40%	25%	0%	0%
Six	20,640	100%	0%	0%	0%	0%
Seven	94,650	86%	0%	11%	3%	0%
Eight	46,870	13%	0%	87%	0%	0%
Ten	37,850	51%	49%	0%	0%	0%
11-17†	69,470	5%	38%	0%	31%	26%
Eighteen	15,839	0%	0%	0%	0%	100%

*High Energy Demand Scenario

+MGD

†All saline and most lake capacity is found in Texas; Capacity on Rivers $\leq$ 50,000 mgd is found in WRC Region 11; Capacity on rivers $\geq$ 50,000 mgd is found in WRC region 17.

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Appendix A

Discussion of Alternative Siting Patterns

A.1 Introduction

This appendix will describe the development of the alternative future plant siting patterns outlined in Chapter Two. The reader will recall these siting patterns are used to estimate what proportions of the new capacity to be installed between 1975 and the year 2000 could use once-through cooling were thermal controls relaxed or removed. The purpose behind developing a number of such siting patterns is to explore the possible ways new electric generating stations could be located on large bodies of water for the purpose of using once-through cooling while at the same time preserving many of the other siting characteristics utility planners consider when selecting a site from a number of potential power plant sites.

Two methodologies are presented here: The first one is based on an extrapolation of historic siting patterns, and is used in the development of siting pattern number one. The second methodology is based on the use of once-through cooling with a lenient thermal standard, and is used in the development of siting patterns two through four.

A.2 Methodology Number One: Extrapolation of Historic Patterns

This siting pattern suggests where new steam electric power plants could locate with respect to the plant water source based on siting pattern trends observed before current thermal regulations were in effect. The premise behind this pattern is that in the absence of thermal controls new power plants could be sited on major bodies of water in the same patterns that were observed prior to the promulgation of the current thermal standards.

The analysis is performed by regional sub area, the smallest level of detail for which we have accurate historic siting pattern data. By examining patterns at the smallest level possible, we are able to capture details of regional growth and regional cooling use patterns which would otherwise be overlooked were the analysis performed for more aggregated areas. For example, in 1975, the electric generating capacities in subareas 307 and 308 made up, respectively, 11.3% and 11.2% of the total capacity within Water Resource Council Region Three. By the year 2000, however, the Federal Energy Regulatory Commission projects that the share within subarea 307 will almost double to 20.7% while the share within subarea 308 will fall to 2.2%. Furthermore, there are fewer rivers that have historically supported once through cooling in subarea 307 than in 308. With the disaggregated analysis we are able to determine that the difference in growth rates between these two subareas will lead to an overall reduction in the use of once-through cooling for these two combined subareas, a result which would not be found were we to lump these two subareas together. Thus the disaggregated analysis allows us to examine changes in cooling system use which are due wholly to differential growth rates among subareas having different capacities to support once-through cooling.

This analysis proceeds along three lines: 1) forecasting the number of megawatts of new capacity that will be installed in every subarea for the two energy demand scenarios considered in this study; 2) assigning new capacity to major bodies of water; and 3) estimating the minimum streamflow which will, from an engineering view of flow conditions and reliability, support once-through cooling.

For the first task, we turn to the Federal Energy Regulatory Commissions's (FERC) energy forecast which projects new capacity additions by subarea for our high energy demand scenario. While the ERDA (low energy demand scenario) projection does not break down new capacity additions by subarea, we reduce every FERC subarea estimate proportionally until the sum of the new additions for all the subareas in the contiguous United States is equal to ERDA's national estimate.

The second task - assigning new capacity to major bodies of water - consists of three steps. We first identify in every subarea the individual rivers, lakes, and, if applicable, coastal sites on which generating stations were located prior to 1973. We then determine what percentages of the pre-1973 capacity in every subarea had been installed on each water source. Finally, we use these percentages to assign to each water source the projected capacity additions for each sub area. We assume generating unit sizes will average 800 MWe for fossil plants and 1200 MWe for nuclear plants. The smallest unit size assigned to a water source is 100 MWe and 500 MWe for fossil and nuclear plants, respectively. Thus if the total amount of fossil or nuclear capacity to be assigned to a water source is less than the respective minimum unit size, this capacity is divided among the remaining water sources in that sub area.

The third task -- estimating the minimum streamflow which can support once-through cooling -- compares the average annual flows observed past units operating with once-through cooling with the flows past units using closed cycle cooling prior to 1973. In its survey of the steam electric power industry, National Economic Research Associates (NERA) found that only 20% of the units operating with closed cycle cooling before 1973 did so to comply with water quality standards (UWAG, 1978). Therefore, we can assume that most plants that installed closed cycle cooling prior to 1973 did so because the flow conditions past the plant could not support once-through cooling with a sufficient reliability of operation. We approach the comparisons from two perspectives, both of which give us similar results.

Our first approach is to analyze the ratio of the average annual river flow versus installed capacity for plants operating with closed and open cycle cooling. Figure A.1 illustrates the separation between closed cycle and open cycle cooling systems as a function of the average flow past known plants in operation before 1973. It is observed that only one plant operated with closed cycle cooling when the flow at the plant exceeded 10 MGD/MWe. On the other hand, fifteen of the ninety six open cycle cooled plants were able to install once-through cooling on rivers where flows were less than 5 MGD/MWe. Using this approach, then, we do not think it is unreasonable to set the minimum annual average streamflow to power ratio at which once-through cooling can be supported at 10 MGD/MWe.

Our second approach is to analyze the ratio of the annual river flow versus the design condenser flow. Figure A.2 illustrates the separation between closed cycle and open cycle cooling systems as a function of the river flow vs. design condenser flow. It is observed that only four plants operated with closed cycle cooling when the river flow was greater than 10 times the design condenser flow. Thirteen of

Figure A.1 Cooling Systems in use Before 1973 as a Function of the Design Plant Capacity v.s. the Average River Flow Past the Plant

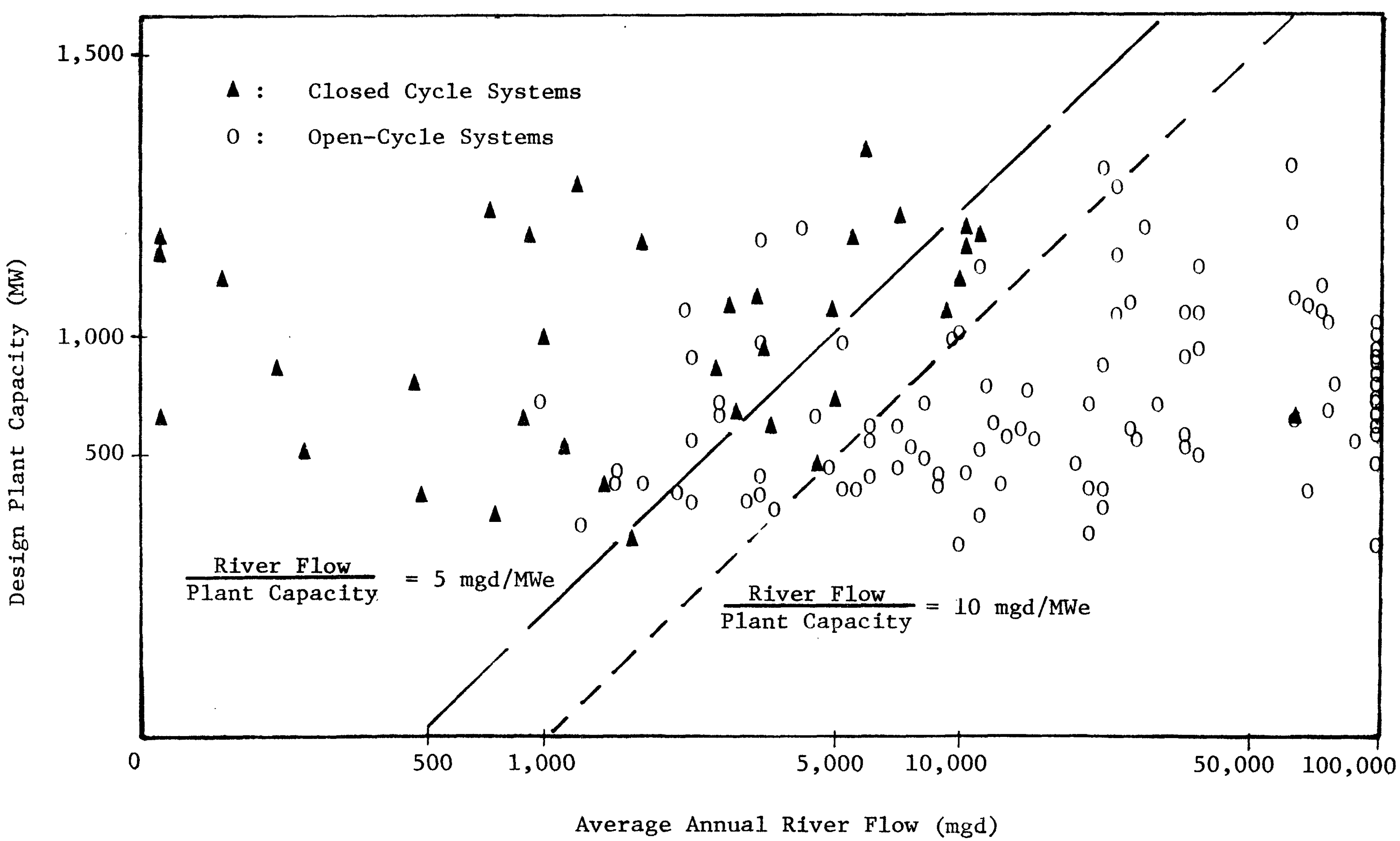
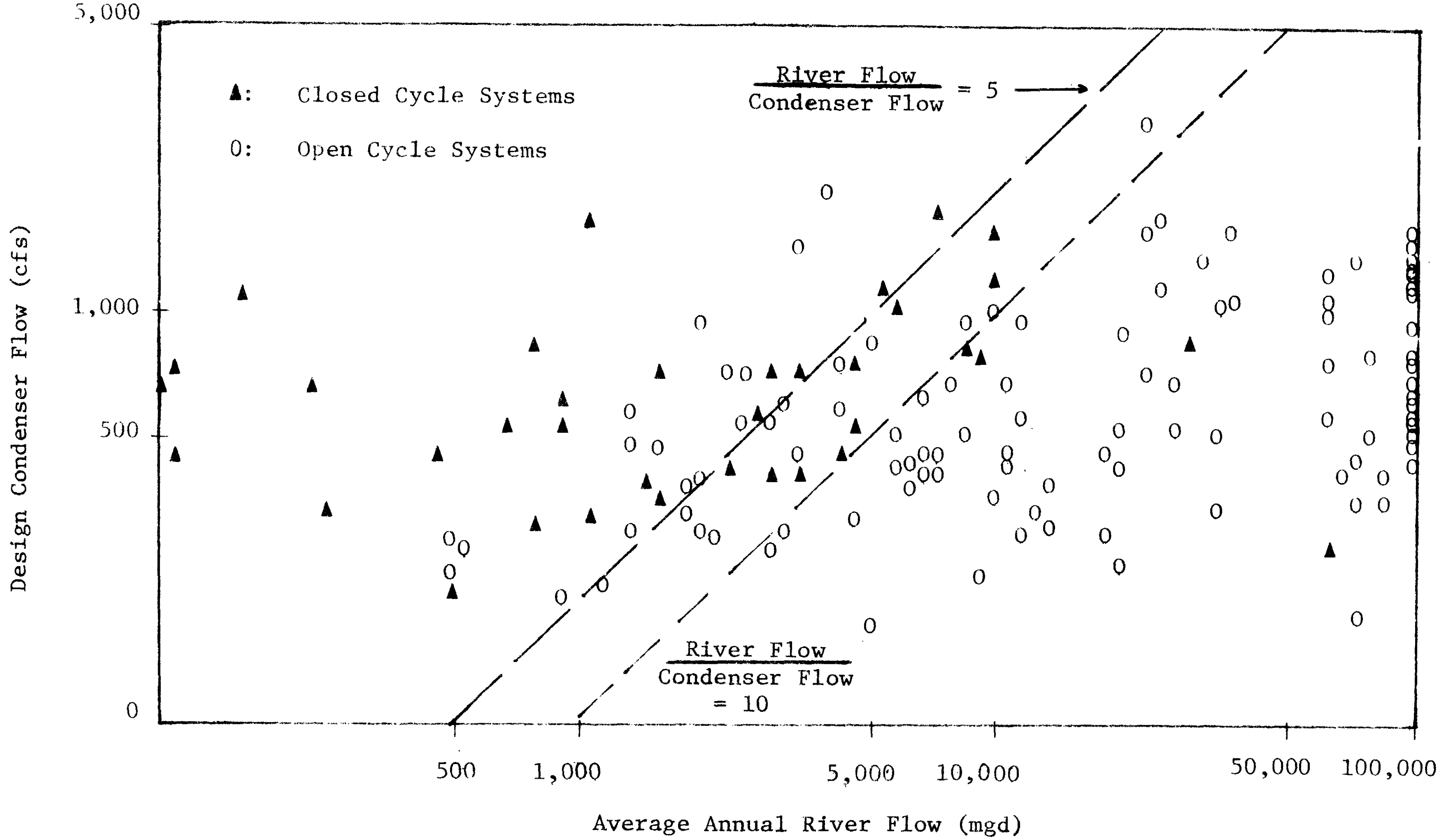


Figure A.2 Cooling Systems in use Before 1973 as a Function of the Design Condenser Flow v.s. the Average River Flow Past the Plant



the ninety-six open cycle cooled plants, on the other hand, were able to install once-through cooling when the average annual riverflow was as low as 5 times the design condenser flow. Using this approach, then, a minimum annual average streamflow to design condenser flow ratio of 10 appears to be a reasonable criteria for the use of once-through cooling.

Najjar (1978) found that for a wide range of economic parameters, the optimal condenser flow rate for a nuclear plant is approximately 0.8 MGD/MWe and for a fossil plant, 0.7 MGD/MWe. We can now compare the results of our two approaches towards finding the minimum streamflow which will support once-through cooling: The criteria developed with the second approach - an annual average streamflow at least ten times the design condenser flow - translates into a streamflow vs. capacity ratio of 8 MGD/MWe and 7 MGD/MWe for nuclear and fossil plants respectively. We notice these ratios are very close to the streamflow vs. capacity ratio of 10 which is found with the first approach. We conclude that both approaches give answers that are reasonably close to each other. The criteria of 10 MGD/MWe is the slightly more conservative of the two criteria and is the one used in this study.

One criticism of the two approaches described above is that the real criteria for the use of once-through cooling should be defined with respect to flow conditions during low flow events (eg., the seven day - ten year low flow) rather than during average flow events. A low flow criteria is certainly the more accurate measure of the reliability with which the river will provide condenser flows. Furthermore there are no consistent functional relationships between average annual flow and say, seven day - ten year low flow that can be uniformly applied for the contiguous United States. For example, taking 7Q10 low flow data from Technekron (1976) and average annual flow data from the Federal Energy Regulatory Commission generating capacity forecasts (FERC, 1975) we find that the ratio of low flow to average flow in all rivers is roughly 0.11 in Water Resource Council Regions One and Two, while this same ratio is roughly 0.22 in Water Resource Council Regions Six and Seven.

Differences in climate, natural hydrology, and streamflow regulation from on-stream reservoirs all contribute to the variation observed in the ratio of low flow to average flow among regions. Therefore, it appears that the average annual flow in a stream is not the best measure of the stream's capacity to support once-through cooling.

While we would prefer to use the seven day - ten year low flow in the development of our criteria for the use of once-through cooling on rivers, these measurements are not readily available with good accuracy on most streams where once-through cooling is found. Thus while the average annual flow is an imperfect measurement the fact that it is readily available plus the fact that our two approaches show a fairly clear and consistent separation between closed cycle and open cycle cooling based on this flow persuades us to use the average flow in our criteria for the use of once-through cooling.

A.3 Methodology Number Two: Maximize Once-Through Cooling Within Limits Imposed by Lenient Thermal Regulations

This methodology, which is used in siting patterns 2,3, and 4, allows once-through cooling at new plants provided lenient thermal regulations will be met. The basic methodology is to determine how many megawatts of new electric generating capacity could be installed with once-through cooling on major bodies of water subject to a somewhat lenient thermal regulation limiting the waste heat induced temperature rise to less than 5°F. For rivers, this hypothetical standard must be met during the low monthly flow expected every twenty years.

To illustrate how this standard of performance represents a "lenient" thermal control it is necessary to compare it with existing standards. The thermal standards for most states will allow thermal discharges which will increase the water temperature above its natural level by no more than 3 - 5°F at the edge of a mixing zone. Typically, the mixing zone in rivers may not involve more than ¼ of the flow or cross-sectional area of the stream. In addition, states typically have more stringent standards for waters classified as cold water fisheries (e.g. trout streams); there the maximum temperature rise is from 0° to 1°F. Furthermore, most states set a maximum absolute temperature (T_{max}) for bodies of water. For warm water fisheries this T_{max} ranges from 83° to 93°F and for cold water fisheries the T_{max} ranges from 65° to 68°F (depending on the latitude at which the body of water is located). Finally, most states limit the temperature rise in lakes and reservoirs to 3°F in the epilimnion and in marine and estuarine environments to 4°F, with the further restriction that during reproductive seasons the temperature rise may not exceed 1.5°F.

We can now see how our hypothetical thermal standard serves as a rather lenient restriction on once-through cooling. First, our allowable temperature rise is equal to the highest currently found in almost all states, and applies to both warm and cold water fisheries. Second, our mixing zone extends across the entire river and not just across one-quarter of the cross-section. That is, while the temperature in the remaining 3/4 of the stream would be less than 5°F if our mixing zone were to follow the conventional standards, our standards allow the temperature in the full section of the stream below the discharge to be raised by 5°F. Finally, we do not impose a constraint on the maximum temperature allowed in the river. That is, under the current standards the natural river temperature during summer months may be equal to or greater than the T_{max} limit during low flows; during these periods plants are not allowed to make additional thermal discharges into that river. Our regulation, however, imposes no such restriction.

Our methodology proceeds as follows: taking a standard plant size of 500 MW we determine how many B.T.U.'s of the incoming energy to the plant boiler will be rejected as waste heat to a water source. For a fossil plant operating with a 38% turbine conversion effeciency and a 15% "loss" between the boiler and the turbine due to stack and in-plant losses the ratio of waste heat to final electric output is:

$$1. \quad \frac{\text{waste heat}}{\text{MWH}} = 3.413 \times 10^6 \frac{\text{BTU}}{\text{MWH}} \cdot \left(\frac{1-.38-.15}{.38}\right) = 4.221 \times 10^6 \frac{\text{BTU}}{\text{MWH}}$$

For a nuclear plant operating with a 32% turbine efficiency and 5% in-plant losses, this ratio is:

$$2. \quad \frac{\text{waste heat}}{\text{MWH}} = 3.413 \times 10^6 \frac{\text{BTU}}{\text{MWH}} \left(\frac{1-.32-.05}{.32}\right) = 6.719 \times 10^6 \frac{\text{BTU}}{\text{MWH}}$$

On the average then the ratio of waste heat to final electric output is approximately:

3. $\frac{1}{2}(6.719 + 4.221) \times 10^6 \frac{\text{BTU}}{\text{MWH}} = 5.47 \times 10^6 \frac{\text{BTU}}{\text{MWH}}$

The temperature of the river just downstream of the plant, assuming the waste heat is completely mixed, is:

4. $$\Delta T_{MIXED} = \frac{5.47 \times 10^6 \frac{\text{BTU}}{\text{MWH}} \times 500 \text{ MW}}{62.4 \frac{\text{lb}}{\text{Ft}^3} \cdot 1 \frac{\text{BTU}}{\text{lb-°F}} \times Q_{low} \frac{\text{Ft}^3}{\text{sec}} \times 3600 \frac{\text{sec}}{\text{Hr}}} = \frac{12170}{Q_{low}} \frac{\frac{\text{°F-Ft}^3}{\text{sec}}}{\frac{\text{Ft}^3}{\text{sec}}}$$

where Q_{low} = the low monthly flow for the segment of a river within a particular ASA.

The residual temperature rise is defined as the difference between the 5°F standard and the mixed temperature:

5. $\Delta T_{RES} = 5° - \Delta T_{MIXED}$

The distance downstream required to dissipate the excess heat is proportional to the ratio $\Delta T_{RES}/5°$, i.e.,

6. $$\frac{\Delta T_{RES}}{5°} = \left(- \frac{K\ W\ x}{\rho c \cdot Q_{low}}\right)$$

where K = surface heat transfer coefficient (BTU/Ft^3-°F-sec)

W = average river width (Ft)

x = the distance required to bring the water temperature from the initial 5°F just downstream of the reference plant to ΔT_{RES} (Ft)

ρc = 62.4 BTU/Ft^3-°F

Solving for x:

7. $$x = \frac{\ln\left[\frac{5}{\Delta T_{RES}}\right] \cdot Q_{low} \cdot \rho c}{K \cdot W}$$

Thus, Eq. (7) solves for the minimum spacing between 500 MW plants operating with once-through cooling such that the 5°F temperature rise standard is not violated on a river having a width W and a low flow Q_{low}. The total once-through cooling capacity of the river within an aggregated sub-area is:

8. O-T Capacity = (L/x) 500 MW

where L = the length of the river within the ASA (Ft)

At lake sites the maximum once-through capacity is determined by calculating the number of acres of lake surface area per MW necessary to remain within the 5°F temperature rise limitation. Assuming the plant efficiencies presented earlier, a 5°F temperature rise, and a representative surface heat transfer coefficient of $K/\rho c = 2x10^{-5}$ Ft/sec, the surface area required is:

9. $$62.4 \frac{lb}{Ft^3} \times 1 \frac{BTU}{16\text{-}°F} \times 5°F \times \text{AREA } Ft^2 \cdot 2x10^{-5} \frac{Ft}{sec} = 1520 \frac{BTU}{MW\text{-}sec}$$

or

10. AREA $\cong$ 243,600 Ft^2/MW $\cong$ 5.6 Acres/MW

The size of every major lake listed in the FERC plant listings can be found from U.S.G.S. guides and atlases, and thus the maximum once-through cooling capacity for each lake may be determined. We limit the number of megawatts using once-through cooling at any site to 5000 MW unless the FERC listing indicates a utility has plans to install a larger capacity at a particular lake site.

For saline sites the number of megawatts that may be installed with once-through cooling is determined by the geometry of the local coastline. Coastal sites for which discharges are made directly into the open area are allowed 5000 MW per site. Partially closed and small bays are allowed 3000 MW per site, and estuaries and almost completely enclosed bays are allowed 1000 MW of once-through cooled capacity per site. Saline sites are examined with the aid of maps to determine coastline configuration.

To summarize so far, our preceeding methodology allows us to determine, for every river segment, lake and (if applicable) coastal site in every aggregated subarea, the number of megawatts of <u>new</u> capacity cooled with once-through cooling that can be installed under the hypothetical thermal regulation.

In siting pattern #2 we do not relocate any capacity, but simply switch as many plants as possible from closed cycle cooling to open cycle cooling on every river segment, lake, and coastal region with the limits established earlier. [eg. Eqs. 8 & 10.] However, even after this has been accomplished some river segments, lakes, or coastal regions in an ASA may have once-through cooling capacity remaining, while others within the ASA may yet have capacity that will be required to install closed-cycle cooling. In siting pattern #3, then, we allow capacity to be transferred <u>within</u> every ASA in order to maximize the number of megawatts operating with open-cycle cooling. After this modification some ASA's still have unused once-through cooling potential, and so in siting pattern #4 we allow capacity to be transferred between ASA's (but always within the larger WRC region itself) in order to maximize the use of once-through cooling by new plants.

Appendix B

Discussion of Economic Parameters

B.1 Introduction

This appendix presents the development of a number of economic parameters used in Chapter 3 of this report. Fuel prices, expected fuel price escalation rates, replacement energy prices and expected replacement energy escalation rates are all found in the literature we have referenced earlier, and are therefore not discussed here. However, there are three parameters that are not readily available per se, but can be derived from existing information: the average utility industry inflation free discount rate; the average utility industry inflation free fixed charge rate; and the inflation free plant cost escalation rate.

In this appendix we will outline both the arguments for using the approaches that we do and the procedures themselves. It is our intention that this section will serve as a guide to other investigators in this field.

B.2 The Derivation of the Real Discount Rate

Our estimate of the average utility industry inflation free discount rate is pegged to the nominal (market) rates of return historically offered on utility bonds. The argument here is that investors will demand a nominal rate of return from their bonds which will cover both the real rate of return desired plus the inflation rate expected during the life of the bond.

That is:

1. $1 + r_N = (1 + DR) \cdot (1 + I_e) = 1 + DR + I_e + DR \cdot I_e$

where: r_N = Nominal rate of return

DR = Real dollar rate of return

I_e = Annual inflation rate expected over the lifetime of the bond

For I_e, $DR < .1$, then:

2. $I_e \cdot DR \ll I_e + DR$

Therefore, as a first approximation we can re-write Eq. (1):

3. $r_N \simeq DR + I_e$

Because future expectations are strongly influenced by past behavior, we expect that the inflation rate investors anticipate for the life of a bond is in some measure dependent on both the current inflation rate and recent trends in the inflation rate. We propose the hypothesis that the anticipated inflation rate is equal to the equivalent inflation rate over the previous "N" years. That is:

4. $I_e^j \cong \{[(1 + i^j)\cdot(1 + i^{j-1})\cdot(1 + i^{j-2})\cdot \cdots \cdot(1 + i^{j+1-N})]^{1/N} - 1\}$

where: I_e^j = Inflation rate expected during the life of a bond issued in year j

i^j = Inflation rate in year j

N = Number of preceeding years over which the average is taken

Examining the seventeen year period from 1960 - 1976 we may compare the gas and electric utility bond rates in any year with the average inflation over the N-years preceeding that year [Edison Electric Yearbook, 1977]. The following regressions are found:

5. $r_N = 0.0451 + .53\ I_e;\quad R^2 = .69;\quad N = 1$

6. $r_N = 0.0418 + .63\ I_e;\quad R^2 = .88;\quad N = 2$

7. $r_N = 0.0398 + .71\ I_e;\quad R^2 = .93;\quad N = 3$

8. $r_N = 0.0399 + .76\ I_e;\quad R^2 = .93;\quad N = 4$

If an underlying hypothesis is correct then, from Eq. (3), we would expect the coefficient for the variable I_e in Eqs. (5) - (8) to equal 1.0. While this condition is not met, thereby weakening the argument of our hypothesis somewhat, we observe that for Eqs. (7) and (8) the observed coefficients are not too far off from the expected value. Therefore, while our hypothesis may have some weak points it nevertheless offers a reasonable explanation of the true behavior affecting utility bond rates. Furthermore, we observed that the y-intercept in Eqs. (5) - (8) tends towards a value of 0.04. As the y-intercept in our regression equations corresponds to the real discount rate, DR, in Eq. (3), we conclude that the inflation free rate of return for the steam electric power industry is approximately 4.0%.

B.3 The Derivation of the Inflation Free Fixed Charge Rate

We wish to remove the inflation component incorporated in the conventional utility industry fixed charge rate from that latter parameter. To do this we propose the argument that the real dollar fixed charge rate should offer the same present valued gross return on capital when dollar flows are discounted by the inflation free interest rate as they would when the nominal fixed charge rate is used and dollar flows are discounted by the nominal interest rate. This argument says:

$$9. \quad \sum_{j=1}^{M} FCR^r \cdot \frac{CAPITAL}{(1+DR)^j} = \sum_{j=1}^{M} FCR^N \cdot \frac{CAPITAL}{(1+r_N)^j}.$$

where: FCR^r = Real dollar fixed charge rate

CAPITAL = Initial capital cost

FCR^N = Nominal fixed charge rate

M = Plant lifetime

DR = Real dollar discount rate

r_N = Nominal discount rate

Rearranging and expanding the terms in Eq. (9) gives:

$$10. \quad FCR^r \frac{[(1+DR)^M -1]}{DR(1+DR)^M} = FCR^N \frac{[(1+r_N)^M -1]}{r_N(1+r_N)^M}$$

The average interest rate on utility bonds during the seven-year period from 1970-1976 was approximately 8.6% [Edison Electric Institute, 1977]. Taking the real discount rate, DR, equal to 4% and the plant lifetime equal to 40 years, we obtain:

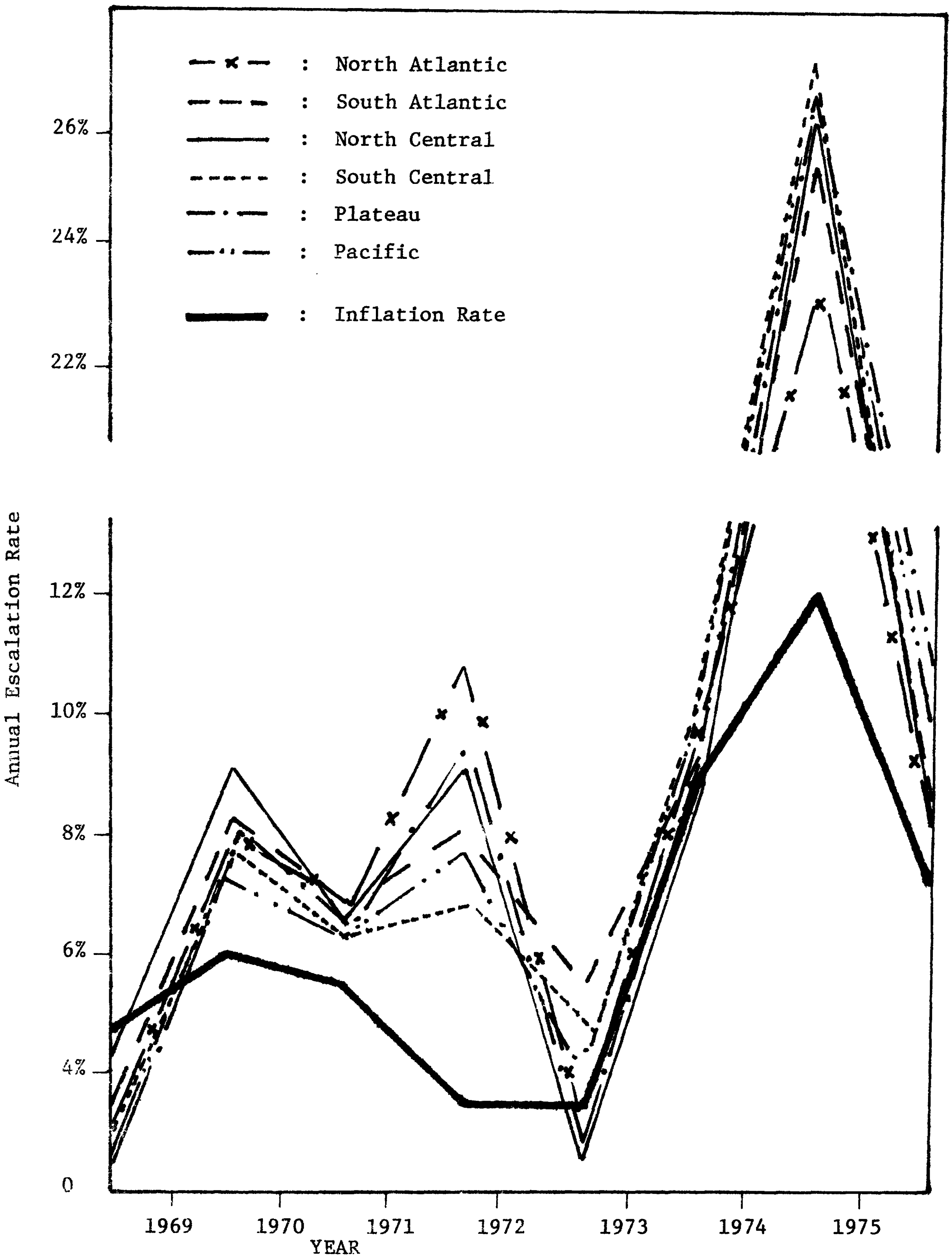
$$11. \quad 19.79 \cdot FCR^r = 11.17 \cdot FCR^N$$

Typical nominal fixed charge rates for the steam electric utility industry are in the range .17 - .19. Therefore, the inflation free fixed charge rate is approximately 0.11.

B.4 The Determination of the Real Dollar Plant Cost Escalation Rate

Figure B.1 illustrates the recent behavior of plant escalation rates for six broad geographical regions comprising the contiguous U.S. [Edison Electric Institute, 1977]. This figure also shows recent movements in the inflation rate. We observe there is some linkage between the nominal plant cost escalation rates in these six regions and the overall inflation rate, where the former almost always exceeds the latter. It appears that the sharp rise in plant costs observed in 1974 is an anomaly with respect to the rest of the record, and will be ignored in our subsequent analysis. Two phenomena are found: 1) on the average, the real dollar plant cost inflation rate was roughly 1.5% from 1969 - 1975; 2) no region has a history of plant cost escalation rates noticeably different from the average. This almost negligible variation in the long-term escalation rates among regions leads us to conclude that all regions will share the same 1.5% real dollar plant escalation rate.

Figure B.1 Regional Plant Cost Escalation Rates Over Time



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