ELECTRIC POWER RESEARCH INSTITUTE

Closed-Cycle Cooling System Retrofit Study

Capital and Performance Cost Estimates

2011 TECHNICAL REPORT

Closed-Cycle Cooling System Retrofit Study

Capital and Performance Cost Estimates

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PRODUCT DESCRIPTION

EPRI is investigating implications of a potential U.S. Environmental Protection Agency (EPA) Clean Water Act §316(b) rulemaking that would establish "Best Technology Available" (BTA) based on closed-cycle cooling retrofits for facilities with once-through cooling. This report focuses on estimated costs associated with closed-cycle cooling system retrofits that include: 1) capital costs, 2) energy required to operate the closed-cycle system, 3) heat rate penalty, and 4) extended downtime required to retrofit some facilities.

Results & Findings

EPRI estimates there are 428 power facilities potentially subject to a retrofit requirements, based on their use of greater than 50 million gallons per day (MGD) of once-through cooling water. These facilities generate approximately 312,000 MW of electricity, including 60,000 MW from 39 nuclear facilities and 252,000 MW from 389 fossil facilities. The potential cost of closed-cycle cooling retrofits—based on capital costs, costs associated with lost revenue from outage time to install the towers and associated structures, and plant operational cost inefficiencies—exceeds a net present value (NPV) of $95 billion or an annualized cost of $7 billion, assuming a 30-year plant life span. The component NPV costs include $62 billion capital, $17.3 billion lost revenue for extended outages to perform retrofits, $8.8 billion for incurred heat rate penalties, and $7.1 billion for lost generation to operate cooling tower fans and water pumps. It is assumed that all facilities would be retrofit with wet mechanical draft cooling towers, which are the most commonly used form of closed-cycle cooling over the past two decades. This report discusses closed-cycle cooling retrofits and provides additional details on the methods used to estimate costs, retrofit challenges, cost breakdowns by nuclear and fossil plants and other factors, and uncertainties associated with the estimates.

Challenges & Objective(s)

Section 316(b) of the Clean Water Act establishes statutory requirements for fish protection at cooling water intake structures (CWISs). In 2004, the U.S. Environmental Protection Agency (EPA) established a rule for implementing Section 316(b) for existing CWISs using >50 MGD. The rule was withdrawn by EPA following a legal challenge and subsequent Second Circuit Court ruling. EPA is currently working on revising the rule for existing facilities, and a draft for public review and comment is expected in early 2011, with a final rule in 2012. The specifics of any future 316(b) rule are uncertain; however, EPA has indicated that closed-cycle cooling retrofits are one option under consideration. While closed-cycle cooling is commonly employed at new generating facilities, retrofit of closed-cycle cooling to existing CWISs is a challenge for a variety of factors, including lack of space, location of existing facility infrastructure, local environmental issues, and economic reasons.

Applications, Values & Use

Information in the report is intended to inform Clean Water Act §316(b) policy development and future rule compliance efforts by the power industry, resource and regulatory agencies, and the public.

EPRI Perspective

Data in this report provide regulators, industry, and other stakeholders with information on the cost implications of basing 316(b) BTA requirements on closed-cycle cooling. Additionally this information is used as input for a project to evaluate the financial and electric system implications of closed-cycle cooling system retrofits as well as a study to estimate the environmental and economic impacts of such retrofits.

Approach

EPRI gathered and evaluated cost information from the industry and developed a cost-estimating model. This model related retrofit costs and facility flow for a subset of nuclear and fossil facilities to establish cost estimates for the various degrees of retrofit difficulty (easy, average, difficult, and more difficult for fossil facilities, and difficult and more difficult for nuclear facilities). EPRI also estimated three additional retrofit costs as a result of lost revenue due to:

- Extended outages necessary for tower installation at some facilities
- Heat rate penalties for most facilities resulting from reduced cooling efficiency
- Increased operating power requirements for cooling towers (fans and pumps)

The capital costs were aggregated and extrapolated to all 428 facilities potentially subject to a retrofit requirement along with estimates of lost revenue due to extended outage time, operating energy requirements for the cooling tower, and the heat rate penalty to provide an estimated national total NPV and annualized costs.

Keywords

Closed-Cycle Cooling
Clean Water Act §316(b)
Fish Protection
Cooling Towers
EPA
Cooling Water Intake Structure (CWIS)

ABSTRACT

The U.S. Environmental Protection Agency (EPA) is currently developing revised regulations for power plant cooling water intake structures under §316(b) of the Clean Water Act. EPA is considering technology-based aquatic life protection performance standards that may require closed-cycle cooling as "Best Technology Available" (BTA) for existing thermoelectric facilities that currently use once-through cooling. This study estimates four closed-cycle cooling system retrofit-related costs, should EPA establish BTA requirements based on results achievable by closed-cycle cooling. EPRI estimates there are 428 power facilities potentially subject to a retrofit requirement, based on their use of greater than 50 million gallons per day of once-through cooling water. These facilities generate approximately 312,000 MW of electricity, including 60,000 MW from 39 nuclear facilities and 252,000 MW from 389 fossil facilities. The potential cost of closed-cycle cooling retrofits—based on capital costs, costs associated with lost revenue from outage time to install the towers and associated structures, and plant operational cost inefficiencies—exceeds a net present value (NPV) of $95 billion or an annualized cost of $7 billion, assuming a 30-year plant life span. The component NPV costs include $62 billion capital, $17.3 billion lost revenue for extended outages to perform retrofits, $8.8 billion for incurred heat rate penalties, and $7.1 billion for lost generation to operate cooling tower fans and water pumps. It is assumed that all facilities would be retrofit with wet mechanical draft cooling towers, which are the most commonly used form of closed-cycle cooling over the past two decades. This report discusses closed-cycle cooling system retrofits and provides additional details on the methods used to estimate costs, retrofit challenges (for example, space constraints), cost breakdowns by nuclear and fossil plants and other factors, and uncertainties associated with the estimates.

EXECUTIVE SUMMARY

This report presents the results of an analysis of the costs of retrofitting with closed-cycle cooling systems those existing steam-electric power plants, which were designed for, built with, and are currently operating on once through cooling. The motivation for this and earlier studies has been regulatory activity subsequent to Section 316(b) of the U.S. Clean Water Act (1-1) in which consideration has been given to requiring all once-through cooled plants to retrofit closed-cycle cooling equipment.

In the current Phase II Rulemaking, EPA is focusing on an evaluation of “Best Technology Available” (BTA) including use of closed-cycle cooling. EPRI initiated a research program to inform the rulemaking on the implications of issuing a Rule requiring closed-cycle cooling retrofits based on the factors the Second Circuit ruled were allowed to consider. Following the Supreme Court decision, EPRI also initiated work to assess benefits relative to the cost. Fundamental to determining if industry can bear the cost of retrofits, impacts to energy production and efficiency and benefits relative to the cost is knowledge of the costs of retrofits for affected Phase II facilities. That is a major motivation for this study.

Purpose of study

The primary objective of this study is to develop an estimate of the national capital cost of retrofitting all the Phase II facilities among power generation plants. Three other significant cost elements were estimated. These are the cost of replacement energy during the time that plants are unable to operate during the retrofit process, the annual cost of additional operating power required for closed-cycle cooling and the cost of heat rate penalties resulting in reduced plant efficiency and output incurred because of thermal limitations of closed-cycle cooling.

Scope

The national cost estimates include the capital, downtime, operating and penalty costs for 428 plants of which 39 are nuclear plants and 389 are fossil plants fueled with coal, oil or gas which withdraw more than 50 million gallons per day (MGD) from the surface waters of the United States.

Methodology

The study focuses on developing a methodology to account for the highly site-specific nature of cooling system retrofit costs in a determination of total national costs. It is well accepted that the retrofitting of existing once-through cooled plants with closed-cycle cooling is significantly more costly, both at an individual plant and on the average, than the installation of closed-cycle cooling at new, greenfield facilities. The methodology consists of three steps. The first two address the estimation of cost at individual plants; the third aggregates and extrapolates individual plant estimates to a national total:

1. Step 1 establishes a likely range of capital costs for a plant simply as a function of the circulating water flow rate in the original once-through cooling system. Separate correlating equations were determined for fossil and nuclear plants.
2. Step 2 places an individual plant cost within the likely range of costs on the basis of the perceived degree of difficulty of a retrofit at that plant. The degree of difficulty is based on site-specific information obtained from a cost-estimating worksheet survey of over 185 facilities. Estimates are made for approximately 125 facilities and a distribution of the family of Phase II facilities over a range of degrees of difficulty from "Easy" to "More Difficult" (for fossil plants) and "less Difficult" to "More Difficult" (for nuclear plants) is extrapolated. For those sites judged to be intermediate between any two of the four dgrees of difficulty the average of the two bounding categories was used.
3. Step 3 estimates the national costs using the number of plants and their cooling water flow rates in each category of difficulty using the cost vs. flow rate correlations developed in Step 1.

In addition, estimates were made of three other significant cost elements. There were the cost of energy replacement during the time a plant is down for retrofitting, the annual cost of additional operating power and the annual cost of the heat rate penalty resulting from thermal limitations of the closed-cycle cooling system.

Estimates of the downtime duration for nuclear and fossil plants were based on a limited number of independent engineering studies for nuclear plants and information from a few actual retrofits at fossil plants.

Key Findings

Cost ranges

Independent information on actual and estimated retrofit costs at over 80 plants yielded likely ranges of costs for individual plant retrofits as a function of cooling water flow rate. Separate equations in the form of

Retrofit Capital Cost, $ = Cost coefficient, $/gpm x Circulating water flow, gpm

were developed for fossil and nuclear plants.

The cost coefficients for the four degrees of difficulty for fossil plant retrofits are:

Easy:	**$181/gpm**
Average:	**$275/gpm**
Difficult:	**$405/gpm**
More Difficult:	**$570/gpm**

The cost coefficients for the two degrees of difficulty for nuclear plant retrofits are:

"Less difficult":	**$274/gpm**
"More difficult":	**$644/gpm**

Degrees of difficulty

After observing the wide variation in cost for retrofitting plants of comparable size, it was concluded that the low, mid-range and high costs corresponded, in a general way, to retrofit projects of varying degrees of difficulty. Based on discussions with plant personnel and architect-engineering firms and the application of professional judgment, the list of 11 factors given in Table ES-1 was compiled which were believed to be the important influences which determine the site-specific degree of difficulty.

Table ES-1
Factors influencing degree of difficulty

Factor	Description
1	The availability of a suitable on-site location for a tower
2	The separation distance between the existing turbine/condenser location and the selected location for the new cooling tower
3	Site geological conditions which may result in unusually high site preparation or system installation costs
4	Existing underground infrastructure which may present significant interferences to the installation of circulating water lines
5	The need to reinforce existing condenser and water tunnels
6	The need for plume abatement
7	The presence of on- or off-site drift deposition constraints
8	The need for noise reduction measures
9	The need to bring in alternate sources of make-up water
10	Any related modifications to balance of plant equipment, particularly the auxiliary cooling systems, that may be necessitated by the retrofit
11	Re-optimization of the cooling water system or extensive modification or reinforcement of the existing condenser and circulating water tunnels

Space constrained sites

At some sites the retrofitting of closed-cycle cooling is simply infeasible due to a lack of space for a cooling tower. In the majority of cases, these sites are located in dense urban locations where there is simply no space available on the site to locate a cooling tower of sufficient size and the surrounding land is occupied, often with valuable urban properties such as apartment or office buildings. In a few cases, at rural sites, the existing facility site itself has no room for a cooling tower. In these rural locations, there may be open, undeveloped adjacent land. In such cases, it may be possible to acquire additional land, unless it is a sensitive area such as unique habitat or a state or federal park.

In addressing this issue, EPA says that "Land upon which to construct cooling towers may be difficult or impossible to obtain." and that "The Agency did not include these potential costs in its analyses."[1] Therefore, in this study any costs for land acquisition are not included, and the assumption is made that if new land must be acquired in order to site a tower, the site is considered to be "infeasible for retrofit". Seven sites, out of the 125 sites for which site-specific analyses were performed, were deemed "infeasible" on the basis that no space was available on which to locate a cooling tower.

Operating power costs

In addition to the initial capital cost, other costs are incurred as a result of a closed cycle cooling system retrofit. Major items are the cost of increased operating power and the cost of reduced plant efficiency and capacity resulting from higher turbine exhaust pressures normally imposed by the retrofit.

The additional operating power required by a closed-cycle cooling system consists of two parts: pumping power and fan power:

- The additional pumping power ranges from a minimum of 0.25% to a maximum of approximately 0.55% of plant output or 2.5 to 5.5 MW for a 1,000 MW plant.
- Similarly, fan power requirements average about 0.6% of plant power or 6 MW for a 1,000 MW plant.
- The sum of the additional operating power required is, therefore, estimated to range from about 0.85 to 1.7% of plant output or 8.5 MW to 17 MW for a 1,000 MW plant.

If the cooling system is re-optimized as discussed in Chapter 7, the usual result is that the circulating water flow is reduced to nominally one-half of what it had been in the original once-through system. Similarly, the cooling tower will have nominally half the cells that would be required if the system had not been re-optimized with a corresponding reduction in the fan power requirement. Therefore, the additional operating power for re-optimized systems would be estimated to range from 4.3 to 8.5 kW/MW.

[1] Federal Register, Vol. 69, p. 41605, July 9, 2004

Efficiency and capacity penalty costs

Conversion of a once-through cooling system to a closed-cycle cooling system using a wet cooling tower frequently results in an increase in the achievable turbine backpressure for most of the year and a corresponding loss of plant efficiency and output. The size of the loss is strongly dependent on details of the relationship between the original source water temperature and the atmospheric temperature and humidity at the site. It is extremely difficult to generalize. A detailed discussion of how the loss is estimated is given in Chapter 7. The annual average loss at sites most adversely affected lies between 2 and 4%. Losses on the hottest days of summer at some sites can be higher.

While nearly all plants will incur some penalty on an annual average basis, some will incur no penalty or even experience increased efficiency or output during the hottest periods of the year. This is the case in situations where

- the summertime source water temperature exceeds the temperature of cold water from a cooling tower,
- the plant output is curtailed to meet once-through cooling discharge temperature limitations or
- low summertime flows in the source waterbody limit plant operations.

Instances of high summertime source water temperature were included in the example sites discussed in Chapter 7 and the slight performance improvements were included in the calculation of an national average penalty. However, there was no available information on the frequency, duration or magnitude of the other two effects and no consideration of them was taken in the analysis.

Cost of downtime

The other significant cost is the loss of revenue during downtime required for the installation of the retrofit cooling system. There is very little information available to establish national averages. However, based on some recent engineering studies and discussions with staff at plants where actual retrofits had been performed, a set of assumed downtimes for nuclear plants, baseloaded fossil plants and other fossil plants were used to develop national estimates for the replacement energy cost of downtime due to retrofits.

National cost estimate

Extrapolation to national totals

The number of plants, total capacity and circulating water flow for in-scope Phase II fossil and nuclear power plants are summarized in Table ES-2 for both fossil and nuclear facilities.

Table ES-2
Capacity and water flows at Phase II Facilities

Plant Type	No. of plants	Total capacity	Total circulating water flow
		MW	gpm
Fossil	389	252,392	139,506,944
Nuclear	39	59,931	42,788,889
Total	428	312,323	182,295,833

If the family of Phase II plants is assumed to have the same distribution of degrees of difficulty as was found for the 125 plants analyzed on a site-specific basis, the cost is approximately $64 billion.

Table ES-3 lists the capital costs plus the additional three cost elements as well as the aggregated costs in the form of an annualized costs and a net present value for the nuclear and fossil plants categorized by the plants' source water types.

Table ES-3
National costs for all Phase II plants categorized by source water type.

Plant Type	Source Water	Capacity	Water Flow	Costs: Capital	Operating Power	Heat Rate Penalty	Downtime	Annualized Cost	Net Present Value
		MW	GPM	$ millions	$ millions	$ millions	$ millions	$ millions	$ millions
Nuclear	Great Lakes	6,000	3,840,000	$1,760	$13	$16	$740	$200	$2,860
	Lakes/Reservoirs	20,000	13,990,000	$6,420	$46	$60	$2,700	$740	$10,430
	O/E/TR	22,000	17,615,000	$8,090	$58	$75	$3,400	$940	$13,140
	Rivers	12,000	7,344,000	$3,370	$24	$31	$1,420	$390	$5,480
	Total Nuclear	60,000	42,789,000	$19,640	$141	$182	$8,270	$2,280	$31,920
Fossil	Great Lakes	27,000	14,242,000	$4,330	$44	$54	$920	$480	$6,460
	Lakes/Reservoirs	61,000	32,831,000	$9,980	$100	$124	$2,120	$1,110	$14,890
	Oceans/Estuaries/ Tidal Rivers	70,000	41,923,000	$12,750	$128	$158	$2,710	$1,410	$19,010
	Rivers	94,000	50,511,000	$15,360	$155	$191	$3,260	$1,700	$22,910
	Total Fossil	252,000	139,507,000	$42,420	$427	$527	$9,010	$4,700	$63,270
All plants	Total Phase II	312,000	182,296,000	$62,060	$568	$709	$17,280	$6,970	$95,190

Additional estimates were made for two different assumptions. The first is the set of all Phase II plants adjusted by the portion of pants assumed to be infeasible to retrofit and reduced by a number of plants assumed to retire rather than retrofit. The second was the adjusted set further reduced by excluding California coastal fossil plants on the basis that they were already directed to retrofit by the California State Water Resources Control Board.

Table ES-4
National retrofit costs for different assumptions

				Costs					
Plant Type	Plants Considered	Capacity	Water Flow	Capital	Operating Power	Heat Rate Penalty	Downtime	Annualized Cost	Net Present Value
		MW	GPM	$ millions	$ millions	$ millions	$ millions	$ millions	$ millions
All plants (nuclear and fossil)	All Phase II plants at original allocation	312,000	182,296,000	$62,060	$568	$709	$17,280	$6,970	$95,190
	All Phase II plants re-allocated for infeasible	312,322	182,295,833	$60,100	$546	$682	$16,827	$6,613	$92,166
	All Phase II plants minus retired at original allocation	286,264	167,892,556	$57,670	$524	$664	$16,818	$6,403	$89,236
	All Phase II plants minus California coastal fossil plants at original allocation	297,507	175,616,667	$60,030	$543	$683	$17,016	$6,619	$92,261
	All Phase II plants minus retired plants and California plants at adjusted allocation	271,449	161,213,389	$53,970	$499	$639	$16,446	$6,068	$84,548

Validation of estimates

The cost estimates in the analysis were compared, where possible, with independent retrofit cost estimates provided by the plants which had been generated by experienced engineering firms or plant engineering departments. There are 35 plants for which both independent cost information and adequate plant/site descriptions on which to base a degree of difficulty estimate were available. Typical agreement for these 35 cases was +/-25% although some differed by as much as 50%. Comparisons were also made between the total retrofit costs for the group of 35 plants and for two subgroups within the 35; namely, California coastal plants and 9 plants for which very complete cost detail had been provided The agreement in the comparative total costs in the large group and in both sub-groups was within 10%. This indicates that the methodology used in this study has no significant bias toward either higher or lower costs in the estimate of the national total cost. It is noted that these comparison could be done only for the capital cost component. No plant-specific information was available with which to validate the other three cost elements.

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1
INTRODUCTION

This report presents the results of an analysis of the costs of retrofitting with closed-cycle cooling systems those existing steam-electric power plants, which were designed for, built with, and are currently operating on once through cooling. The motivation for this and earlier studies has been regulatory activity subsequent to Section 316(b) of the U.S. Clean Water Act (1-1)[2] in which consideration has been given to requiring all once-through cooled plants to retrofit closed-cycle cooling equipment. The primary objective of this analysis is to develop an estimate of the national capital cost and associated operating and maintenance costs and plant efficiency penalties of implementing closed-cycle retrofits on all applicable units.

Background

Legislative and regulatory history

In 1972, Congress amended the Clean Water Act (CWA) to regulate cooling water intake structures. Specifically, §316(b) of the CWA requires EPA to ensure that "the location, design, construction and capacity of cooling water intake structures shall reflect the best technology available for minimizing adverse environmental impact." (1-2). EPA's first attempt to promulgate regulations under 316(b) was remanded by the Fourth Circuit court in 1977 on procedural grounds. No new rule was issued for many years until the Agency, under a consent decree, established a schedule for conducting a §316(b) rulemaking proceeding in three phases: Phase 1 covering "new facilities"; Phase II, covering existing steam electric power plants that commenced construction on or before January 17, 2002 and that withdraw more than 50 million gallons per day (MGD) from waters of the United States; and Phase III, covering all existing facilities, including power plants and industrial facilities, not covered by Phase II. This study is not related to any facilities covered by either the Phase I or Phase III rulemakings.

The Phase II rule addressed existing facilities which are the subject of this study and was issued on July 9, 2004 (1-3). The rule was challenged by a number of environmental groups led by Riverkeeper, Inc. as well as several state environmental agencies, two power companies and the Utility Water Act Group. The challenges were consolidated into a single case which was argued before the United States Court of Appeals for the Second Circuit on June 8, 2006 and in which a decision was issued on January 25, 2007.

[2] References listed in order within each chapter; i.e., (Chap. #-Ref. #). Complete citation lists are at the end of each chapter.

One of the major issues in the case was the role of cost in determining "Best Technology Available" (BTA). Environmental groups and states argued that EPA had violated §316(b) by rejecting closed-cycle cooling as the basis for §316(b) performance standards based on the Agency's weighing of costs and benefits. The Second Circuit decision (1-4) rejected the use of "cost-benefit" analysis.

Although the Second Circuit Decision held that cost/benefit considerations could not be used to reject closed-cycle cooling retrofits as BTA, retrofits could be rejected if the industry could not bear the cost or if there were significant adverse environmental impacts or impacts to energy production and efficiency.

The Second Circuit's holding prohibiting use of cost-benefit analysis under §316(b) was appealed to the U. S. Supreme Court (1-5). The appeal was granted, and the case was argued on December 2, 2008. The Supreme Court issued its decision on April 1, 2009 (1-6) and determined that EPA could consider benefits relative to costs in making the BTA determination.

While that appeal was underway, EPA issued a memorandum dated March 20, 2007, to EPA's Regional Offices announcing withdrawal of the §316(b) Phase II Rule. This was followed by a notice in the Federal Register on July 9, 2007. Specifically, the memorandum and Federal Register notice stated the withdrawal of the Rule was a result of the impact of the Second Circuit's remand's impact on the overall compliance approach. EPA determined that so many of the Rule's provisions were affected by the Decision that the overall Phase II approach was no longer workable for compliance. The memorandum and Federal Register notice further directed EPA Regional Offices and delegated states to implement §316(b) in NPDES permits on a BPJ basis, until issues underlying the Second Circuit decision were resolved. EPA then assembled a team to initiate work on a revised §316(b) regulation based on the Second Circuit Decision.

Because EPA has said that, in revising the Rule, it will focus on an evaluation of BTA including use of closed-cycle cooling, EPRI initiated a research program to inform the rulemaking on the implications of issuing a Rule requiring closed-cycle cooling retrofits based on the factors the Second Circuit ruled were allowed to consider. Following the Supreme Court decision, EPRI also initiated work to assess benefits relative to the cost. Fundamental to determining if industry can bear the cost of retrofits, impacts to energy production and efficiency and benefits relative to the cost is knowledge of the costs of retrofits for affected Phase II facilities.[3] That is a major objective of this report. Additional objectives are to provide a better understanding of the impacts to energy production as a result of energy requirements of closed-cycle cooling systems or facility outages required for retrofits.

Prior studies

Throughout the period of legislative, regulatory and judicial activities summarized above, a number of studies have been conducted. These studies have recognized, as did the regulatory process, significant differences between the application of closed-cycle cooling at new plants and

[3] For the current Rulemaking, the EPA has combined consideration of what had been Phase II and Phase III facilities into a single category called "Existing Facilities". For the purpose of this study, the analyses will consider only those facilities formerly included under the Phase II categorization

the retrofit of existing plants from once-through to closed-cycle cooling. Those differences are of major importance in both the design and construction phases.

The design issues are related to the fact that closed-cycle cooling usually provides warmer cooling water and hence higher turbine exhaust pressures than does once-through cooling. Therefore, if a plant is designed originally for closed-cycle cooling, the selection of the turbine, the condenser and other major plant components will be made to accommodate the turbine exhaust pressure for that system while still providing the desired plant capacity at acceptable efficiency. A closed-cycle cooling system retrofit to an existing plant with a turbine, condenser and other components originally selected for different conditions will usually incur efficiency and capacity penalties.

Similarly, the installation and construction is typically far more difficult for retrofits at existing plants than for new plants at "greenfield" sites. Primary difficulties are a lack of available space close to the existing turbine halls for cooling towers and the presence of numerous, on-grade, underground and overhead interferences to the installation of circulating water lines between the existing condenser and the new cooling tower. These factors, while entirely site-specific, can, and typically do, result in cooling system retrofit capital costs which are significantly higher than the expected cost for a comparably sized system at a new plant.

Studies by both Federal and State agencies and by industry under the direction of the Utility Water Act Group (UWAG) and the Electric Power Research Institute (EPRI) or by individual plants have attempted to estimate the capital and performance costs of such retrofits.

Federal studies include the original development documents assembled as part of the Phase I and Phase II Rule makings (1-7, 1-8) by EPA and a supporting study by the U.S. DOE (1-9). The State of California sponsored an analysis of the cost of retrofit of ocean plants. (1-10).

Industry studies include two by UWAG: one by the Washington Group (1-11) and one by the Stone & Webster Engineering Corporation (1-12). EPRI has sponsored two cost studies prior to this one: The first, in 2002, submitted as part of the original Phase II Rulemaking process (1-13); the second in 2005 specifically directed at California ocean plants. (1-14). Also, an interim report (1-15) on the present study was submitted to EPA in May, 2008 to assist in informing the on-going development of revised regulations in response to the remand of the original Phase II rule by the Second Circuit Court of Appeals.

This study is part of a larger, comprehensive effort by EPRI which consists of four separate studies. The complete project includes:

1. Estimation of the cost of retrofitting Existing Facilities with closed-cycle cooling (Maulbetsch Consulting)
2. Determination of impacts to energy production and supply by quantification of the number of facilities/Units/MW at risk of closure and the loss of MW due to retrofitting (Veritas Economic Consulting)
3. Quantification of the adverse environmental and social impacts associated with closed-cycle cooling compared to impingement and entrainment losses (URS Corporation)

4. Identification of impacts to transmission system reliability and electric power supply based on results of the second project (Veritas Economic Consulting and PwrSolutions)

Scope

This study develops an estimate of the national cost of retrofitting with closed-cycle cooling systems all electric power plants which had been classified as "Phase II facilities" under Section 316(b) of the Clean Water Act.[4] There are approximately 428 power plants in the U.S. at which all or some of the units are operating on once-through cooling with cooling water intake structures which had been classified as "Phase II Facilities" for purposes of regulation under Section §316(b) of the Clean Water Act (1-1). These plants are listed in Appendix A.

The project consists of several tasks beginning with the development of a methodology for cost estimation in which a range of expected retrofit costs for plants of different types and cooling systems of given capacity is established. Then for an individual plant, its expected position within that cost range is determined based on an estimated "degree of difficulty" of the site-specific retrofit. Subsequent tasks include the identification and acquisition of extensive cost data from actual retrofits and cost estimates from planned retrofits, the development of correlations which define the expected range of costs, and the solicitation of site-specific information from all of the Existing Facilities on which to base the "degree of difficulty" for each.

Many of the plants solicited provided some or all of the information requested. From those plants, a group of plants is selected which best represents the complete family of Existing Facilities by having a similar distribution of plant size, plant type, source water type and geographical location. Plant-specific estimates are made of the degree of difficulty and the corresponding retrofit capital cost for that group of plants. These estimates are then validated by comparison to any available independent cost estimates. These results from these selected plants are then extrapolated to the complete family of Existing Facilities and general qualitative estimates are made of the probable national cost of retrofitting all applicable Existing Facilities.

In addition to the capital cost of retrofitting the plant cooling system, there are other costs resulting from the effects of the retrofit. Major items include the cost of any increased operating power or maintenance requirements, the cost of reduced plant efficiency and capacity due to increased turbine exhaust pressure and the cost of replacement energy which must be provided to the power grid during periods when the plant cannot operate because of retrofit project construction activities. These costs are estimated for a variety of site-specific situations, generalized and extrapolated to an estimate of the total magnitude of those effects on the Nation's electric power grid.

[4] Evaluating whether a cooling system incorporating a cooling pond or impoundment qualifies as closed-cycle cooling or open-cycle was beyond the scope of this analysis. Thus, for purposes of this analysis, it was assumed that all such facilities were at risk of being treated as open-cycle systems, unless the facility has received a determination to the contrary.

Organization of report

The remainder of this report is organized as follows.

Chapter 2 contains a detailed description of the approach adopted in the study. That description includes a complete explanation of the "degree of difficulty" concept and its relationship to cost correlations based on independent cost information from actual and planned retrofits. Also, the set of closed-cycle cooling retrofit technologies considered or excluded from consideration for use in retrofit applications is discussed.

Chapter 3 reviews the independent cost data, the sources from which they were obtained and the development of the cost correlations which establish the expected cost range. Plants for which independent cost data were available are listed in Appendix B.

Chapter 4 describes the factors used to establish the degree of difficulty of retrofit at individual sites and the approach taken to acquiring site-specific information on these factors from as many of the existing facilities as possible. Plants for which site-specific information was provided are listed in Appendix C.

Chapter 5 summarizes the results of site-specific analyses of 100 plants selected to be as representative as possible of the family of 428 Phase II facilities. Particular attention is paid to detailed descriptions of the retrofit project at 9 plants for which either actual costs or very detailed and thoroughly documented costs are available. Appendix D lists the plants for which site-specific analyses were conducted. Appendix E contains brief write-ups of each plant.

Chapter 6 compares the results of estimates using the methodology developed in this study to those plants for which both site-specific information from which estimates could be made and independent cost information were available. The validity and reliability of the methodology is evaluated on the basis of these comparisons.

Chapter 7 provides a discussion of and some estimating methods for those retrofit costs that are not captured in the simple capital costs of retrofit. These include operating power cost for circulating water pumps and cooling tower fans, cooling tower maintenance costs, the costs of efficiency and capacity penalties imposed on the plant by cooling system limitations, and other related costs incurred as a result of a cooling system retrofit, such as licensing and permitting costs. The discussion presents and explains the methodology for each category of costs and presents some illustrative examples.

Chapter 8 presents estimates of the potential cost of closed-cycle cooling system retrofit if it were to be applied uniformly on a national basis. A number of scale-up methods are proposed and evaluated for using cost estimates developed for the limited set of plants for which estimates could be made with some level of confidence to extrapolate a cost estimate for the entire family of Phase II facilities in the power industry.

Finally, Chapter 9 summarizes the report and presents the major, important conclusions.

References—Chapter 1

1-1: Federal Water Pollution Control Act ("Clean Water Act"), 33 U.S.C. 1251 *et seq.*, November 27, 2002

1-2: Federal Water Pollution Control Act, §316 (b), 33 U.S.C §1326(b)

1-3: 40 CFR Parts 9, 122 – 125, Final Regulations to Establish Requirements for Cooling Water Intake Structures at Phase II Existing Facilities, 69 Fed. Reg. 41,576, July 9, 2004.

1-4: Riverkeeper, Inc. *et al.* vs. United States Environmental Protection Agency; Decision from United States Court of Appeals for the Second Circuit, Docket Nos. 04-6692-ag(L) *et al., January 25, 2007*

1-5: United States Supreme Court, Docket No. 07-588, 07-589 and 07-597 (Consolidated), Available at http://www.supremecourtus.gov/docket/07-588.htm), December 2, 2008.

1-6 Entergy Corp. *v*. Riverkeeper, Inc., *et al.,* (2009) 129 S.Ct. 1498, 173 L.Ed.2d 369

1-7: EPA Technical Development Document for the Final Section 316(b) Phase II Existing Facilities Rule, EPA-821-R-04-007, February 12, 2004.

1-8: EPA Economic and Benefits Analysis for the Final Section 316(b) Phase II Existing Facilities Rule, EPA-821-R-04-005, February, 2004.

1-9: *An Investigation of Site-Specific Considerations for Retrofitting Recirculating Cooling Towers at Existing Power Plants---A Four Case Study,* Parsons Infrastructure and Technology Group and the National Energy Laboratory, U.S. Department of Energy, May, 2002.

1-10: *California's Coastal Power Plants: Alternative Cooling System Analysis*, Tetra Tech, Inc., Golden CO; T. Havey, Project Manager, Prepared for California Ocean Protection Council, February, 2008. (Available at http://www.waterboards.ca.gov/water_issues/programs/npdes/cwa316.shtml):

1-11: *Estimated Cost of Compliance with EPA Proposed Rule 316(b) of the Clean Water Act*, The Washington Group, International, Submitted to Hunton & Williams for the Utility Water Act Group, December, 2001.

1-12: Yasi, D.E. and T.A. Adams, Jr., *Engineering Cost Estimate for Retrofitting Recirculated Cooling systems at Existing Facilities,* Stone & Webster Engineering Corporation, Report to Hunton & Williams for the Utility Water Act Group, July, 2003. (Available at http://www.epa.gov/waterscience/316b/phase2/comments/index.html)

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1-14: *Issues Analysis of Retrofitting Once-Through Cooled Plants with Closed-Cycle Cooling: California Coastal Plants*, EPRI, Palo Alto, CA 2007. TR-052907

1-15: *Closed-Cycle Retrofit Study: Capital and Performance Cost Estimates,* EPRI, Palo Alto, CA: Interim report, submitted to EPA, May, 2008

2
COST ESTIMATING METHODOLOGY

Introduction

This chapter describes the general approach to the development of a national cost estimate for retrofitting closed-cycle cooling systems to existing facilities, originally designed for, built with and currently operating on once-through cooling systems. A complete list of the approximately 428 in-scope existing facilities is presented in Appendix A.

In once-through systems, cooling water is withdrawn from a natural waterbody, passed once through the power plant cooling system and then returned to the source waterbody. As illustrated in Figure 2-1, the cooling system consists of a steam condenser, typically of the shell-and-tube type, circulating water pumps, circulating water lines, intake and discharge structures and, in most cases, some water treatment equipment, typically chlorination for biofouling control. At some plants, water for cooling is stored or impounded in a reservoir, lake or pond which is constructed specifically for the plant cooling system. In such systems, the impoundment rejects heat from its surface to the atmosphere by evaporation and water is withdrawn from the nearby natural waterbodies only to replace water lost to evaporation.

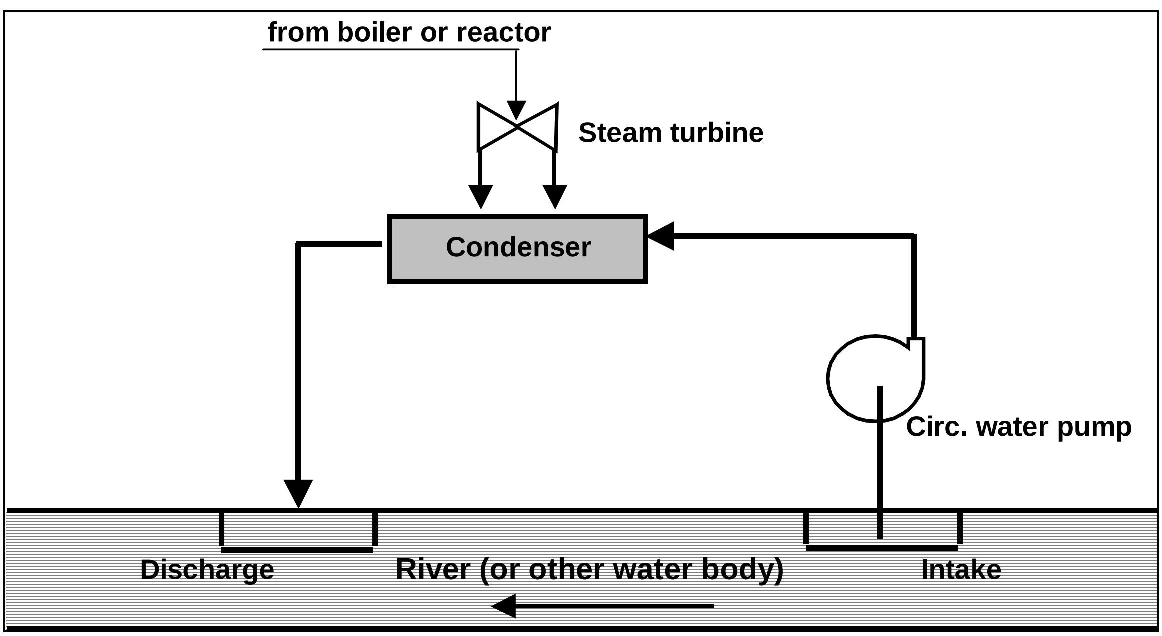

Figure 2-1
Schematic of once-through cooling system

Closed-cycle (or recirculating) wet cooling systems are similar to once-through cooling in that the steam is condensed in a water-cooled, shell-and-tube steam condenser, but differ in that the heated cooling water is not returned to waters of the U.S. but is conveyed to a cooling component, typically a wet cooling tower (other options include cooling ponds, spray enhanced ponds, spray canals, etc.) where it is cooled and then recirculated to the condenser. A typical closed-cycle wet cooling system is shown schematically in Figure 2-2.

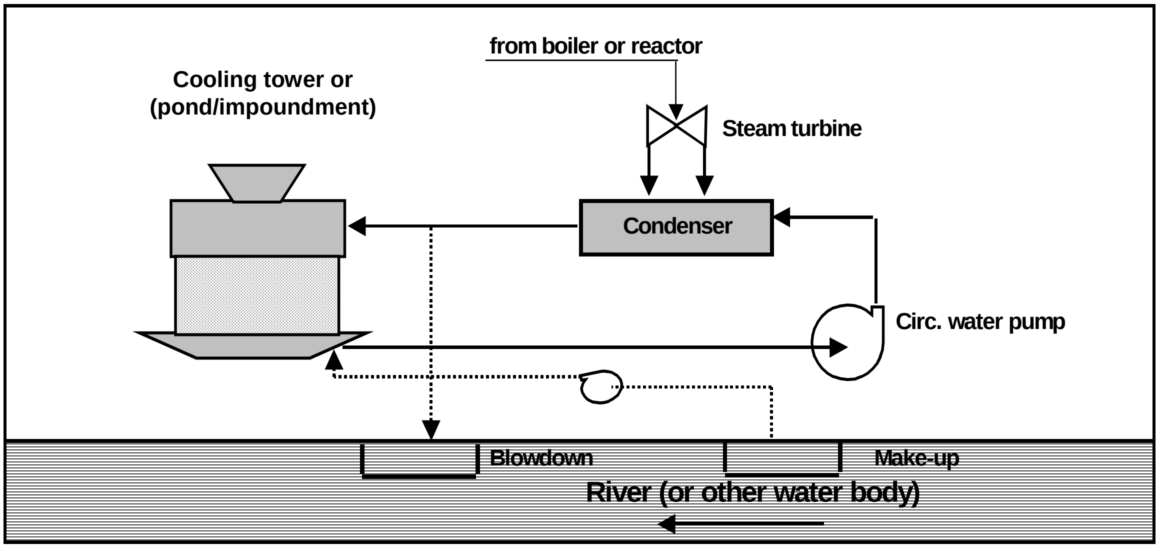

Figure 2-2
Schematic of closed-cycle wet cooling system

The important difference in the context of this study is that the amount of water continuously withdrawn from the natural waterbody is significantly greater for once-through systems. As will be discussed in greater detail in Chapter 3, typical withdrawal rates for once-through cooling range from 400 to 700 gallons per minute (gpm) for each megawatt (MW) of plant generating capacity. Alternatively, closed-cycle systems withdraw only enough water to replace that lost by evaporation to the atmosphere and blowdown to the environment; typically 10 to 15 gpm per MW or approximately 2 to 7% of that withdrawn by once-through cooling. It is noted, however, that closed-cycle cooling systems consume most of the water that they take in through evaporation to the atmosphere. In fact, water consumption, as opposed to withdrawal, in closed-cycle systems is actually greater than it is for once-through cooling for a given heat load.

Figure 2-3 illustrates a basic approach taken in retrofitting closed-cycle cooling systems.

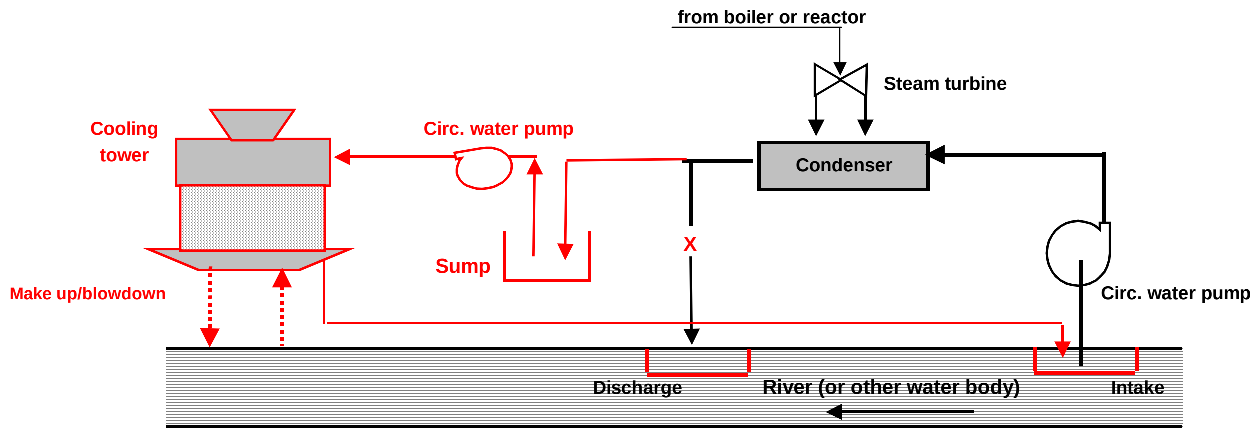

Figure 2-3
Basic approach to retrofit

The existing once-through cooling arrangement in most cases is left largely intact with the same condenser, the same set of circulating water pumps and intake discharge lines and operates at the same circulating water flow rate. However, the existing intake and discharge facilities are modified or eliminated. The hot water from the condenser is discharged into a sump from which a new set of circulating water pumps draws the hot water and pumps it to a new cooling tower. The cold water from the cooling tower then drains by gravity from the cold water basin back to an intake bay from which the original circulating water pumps draw water to be pumped to the condenser. Provisions for both makeup and blowdown from the closed-cycle system must be made to replace water lost by evaporation and blowdown to control the buildup of suspended and dissolved solids in the cooling loop.

Many variations on this retrofit arrangement are possible. Depending on the existing type of intake and discharge systems, it may be possible to use existing intake or discharge bays or canals in place of a new sump for the withdrawal and discharge points of the new circulating water loop to and from the tower. In some cases, it is possible to modify the existing circulating water pumps so that the cooling water can be pumped through the condenser and then directly to the top of the tower without the need for a second set of pumps or an intermediate sump. In some cases, it may not be possible to find a location for the tower which permits gravity return of the cold water. In that case, additional return pumps would be required. However, all of these modifications retain the basic premise of the retrofit; i.e., that the existing condenser and cooling water flow rate are retained and a cooling tower is, in some sense, simply inserted into an existing cooling loop in order to recirculate cold water to the condenser and, by so doing, to significantly reduce the continuous withdrawal rate of water from the environment.

Significantly different approaches to closed-cycle cooling system retrofits are possible. Some examples include the use of natural-draft cooling towers in place of mechanical-draft towers, the use of dry cooling in place of wet cooling and a complete re-optimization of the existing system to a different cooling water flow rate and condenser configuration. These options and their relationship to the general conclusions of the study will be discussed in later sections.

General Approach

As noted earlier, the primary objective of this study is to develop the national costs and the effects on plant efficiency and capacity from retrofitting closed-cycle cooling systems to the family of once-through cooled existing facilities. The general approach to conducting the study to achieve this objective consisted of several steps.

Cost determination

Independent cost information

The initial step was to assemble all available independent retrofit cost information to establish the probable range of costs. An earlier EPRI study (2-1) had collected cost data on 58 plants by soliciting information from individual utilities and from reports by DOE (2-2, 2-3). In the current study, additional information was obtained from both new and updated estimates by utilities. Independent cost estimates for 82 plants were obtained and are listed in Appendix B.

The data were sorted and examined to find consistent trends for plants, source water and site characteristics. The general trend of costs show an increase with increasing plant size or circulating water flow as would be expected, but very large cost differences exist at all levels of plant size and flow rate. Therefore, correlations were developed for four levels of lower, intermediate and higher cost retrofits. Separate correlations were developed for fossil and nuclear plants. The analyses of the data and the development of the resulting correlating equations are described in detail in Chapter 3.

Site-specific characteristics

After observing the wide variation in costs for retrofitting plants of comparable size, it was assumed that the variation corresponded, in a general way, to retrofit projects of varying degrees of difficulty. They were characterized as “Easy”, “Average”, “Difficult” and “More Difficult” (or “Less Difficult” and “More Difficult” in the case of nuclear facilities).. Based on discussions with plant personnel and architect-engineering firms and the application of professional judgment, the list of eleven factors given in Table 2-1 was compiled which were believed to be the important influences which determine the site-specific degree of difficulty.

Table 2-1
Site-specific factors affecting the cost of retrofit

Factor	Description
1	The availability of a suitable on-site location for a tower
2	The separation distance between the existing turbine/condenser location and the selected location for the new cooling tower
3	Site geological conditions which may result in unusually high site preparation or system installation costs
4	Existing underground infrastructure which may present significant interferences to the installation of circulating water lines
5	The need to reinforce existing condenser and water tunnels
6	The need for plume abatement
7	The presence of on- or off-site drift deposition constraints
8	The need for noise reduction measures
9	The need to bring in alternate sources of make-up water
10	Any related modifications to balance of plant equipment, particularly the auxiliary cooling systems, that may be necessitated by the retrofit
11	Re-optimization of the cooling water system or extensive modification or reinforcement of the existing condenser and circulating water tunnels

Examination of these factors at an individual plant leads to a judgment of whether a retrofit at that plant would be easy, average or difficult. In principle, each of the Phase II facilities could be examined, ranked as to degree of difficulty and a cost assigned from the low, average or high cost correlations. Clearly an on-site examination or even a detailed telephone discussion of the factors at each plant would require effort and expense well beyond the scope of this study. Therefore, a cost estimating worksheet was constructed which asked questions and requested data, drawings or other information relevant to the evaluation of each of the important factors on the list. The worksheet was distributed to the industry with the assistance of major associations that included EPRI, EEI, UWAG, NERA and APPA with a request that it be completed and returned for each once-through cooled facility owned by the Company. From the worksheets which were returned and contained adequately complete information, 125 plants were selected for site-specific analysis. (See list in Appendix D) The process of acquiring and cataloging the results from these worksheets is discussed in Chapters 4 and 5.

Concurrently, nine plants were identified for which either actual retrofit costs or detailed cost estimates produced by professional engineering firms with extensive power plant construction experience were available. For these sites, sufficient detail was obtained on plant/site characteristics and the cost breakdown among the many elements of the project cost to enable the development of insight into the influence of many of the factors listed in Table 2-1 on the total project cost. Analyses of these nine plants are summarized in Chapter 6.

The analyses of these nine cases aided in the evaluation of the 125 sites chosen for site-specific analysis based on worksheet information. Each of these 125 plants was assigned a degree of difficulty from easy to more difficult. Summary write-ups for each of the plants analyzed are found in Appendix E. A review of the conclusions and trends and a categorization of the results by plant and site characteristics are given in Chapter 5.

From these ratings, a cost estimate was made for a retrofit at each plant using the correlations described in Chapter 3. In a few cases, a retrofit was considered completely infeasible at any cost. A brief discussion of the criteria used for classifying a plant retrofit as “infeasible” and a few examples of such situations are given in Chapter 4.

Two steps remained for the final estimate of the national total capital costs for retrofitting the family of Phase II facilities. The first was a test of the validity and consistency of the cost estimating methodology by comparison of the estimates with independent cost information. There are approximately 35 plants for which both independent cost information and adequately completed worksheet were available. The results of these comparisons are presented in detail in Chapter 6.

Finally, the cost estimates for the plants which were analyzed were aggregated and extrapolated to provide an estimated national total cost. The extrapolation procedure is described and the results presented in Chapter 8.

Other considerations

In addition to the estimated capital cost of the retrofit which is determined as described above there are additional costs which may be incurred as a result of the cooling system retrofit. These include three estimated in this study:

1. Additional operating power requirements and any increased maintenance costs
2. Effect of the modified cooling system on plant efficiency and capacity
3. Costs of plant “downtime” while the retrofit is being installed

and additional assorted costs that include:

- Capital project finance costs
- Labor and chemical costs of cooling tower operation
- Permitting and licensing costs
- Cost of any necessary electric system upgrades due to facility retirement or reduced generation as a result of the retrofit
- Cost of environmental and social impacts of the cooling tower.

The approach to assessing the first three costs is described in the following paragraphs. A detailed discussion of the analysis and the results is given in Chapter 7

Estimate of operating power costs

A retrofitted closed-cycle cooling system using mechanical-draft cooling towers will always consume more operating power than was consumed by the original once-through cooling system. Specifically for the case of mechanical draft cooling towers, additional power is needed for the circulating water pumps to raise the water flow to the top of the tower and for the fans to draw air through the tower fill.

The amount of additional pumping power will depend on the configuration of the new circulating water circuit, the location of the cooling tower and its elevation relative to the steam condenser and the height of the tower. The additional fan power will depend primarily on the size of the cooling load and the number of cells in the cooling tower but to some degree on the design philosophy chosen for the new tower. While a detailed retrofit configuration analysis and operating power estimate for each site is beyond the scope of this study, certain generalized rules of thumb were developed which are consistent with a reasonable approach to cooling system retrofit. These estimates and the method for arriving at them are presented in detail in Chapter 7.

Estimate of effect on plant efficiency/capacity

The retrofitted closed-cycle cooling system will also, for most of the year for most facilities, deliver cooling water to the condenser at a higher temperature than would be available from the natural water source used for once-through cooling. This results in a higher condensing temperature and a correspondingly higher turbine backpressure, which leads to lower plant efficiency, and reduced output. The magnitude of this effect is a function of the closed-cycle cooling system design and the climate at the site. The climatic feature of most importance is the annual variation in the difference between the original natural source water temperature and the local wet bulb temperature.

While a plant by plant analysis of the magnitude of the effect on plant capacity is again beyond the scope of this study, a general approach to estimating the magnitude of this effect is provided in Chapter 7.

Estimate of cost of downtime

The time for which the plant must be taken off-line and out of operation for the construction and installation portions of the cooling system retrofit can vary from a few weeks such that cooling tower tie in could be accomplished during a scheduled maintenance outage to several months to over a year. The length of the downtime is influenced by the complexity of the plant layout, the design philosophy adopted for the retrofit, the plant’s capacity factor and operating schedule and other factors. There is relatively little information available to support generalized estimates of this cost element. A few illustrative examples are given in Chapter 7, and an approach to assigning a range of downtimes for each plant is proposed. It is recognized that this element of the cost estimate is highly uncertain as applied to any individual site.

Additional costs

Cooling system retrofits are large scale projects which influence the effect of the plant on the surrounding neighborhood and can result in environmental effects which were not present with the original once-through cooling system. A detailed analysis of the environmental trade-offs is the subject of a companion report (2-4) However, the project may trigger a number of related licensing/permitting requirements which carry their own substantive and procedural prerequisites. Obtaining the required permits may involve extensive time, effort and consulting assistance which can add a significant cost to the overall retrofit costs. It is beyond the scope of this project to draw any general conclusions regarding these costs, but a brief discussion with some illustrative examples is presented in Chapter 7.

References—Chapter 2

2.1 Cooling System Retrofit Cost Analysis, EPRI, Report No. 1007456, October, 2002

2.2 Veil, John A., Impact on the Steam Electric Power Industry of Deleting Section 316(a) of the Clean Water Act, ANL/EAI8-4, Argonne National Laboratory, U. S. Department of Energy, January, 1993.

2.3 An Investigation of Site-Specific Considerations for Retrofitting Recirculating Cooling Towers at Existing Power Plants---A Four Case Study, Parsons Infrastructure and Technology Group and the National Energy Laboratory, U.S. Department of Energy, May, 2002.

2.4 Adverse Environmental and Social Impacts of Cooling System Retrofits, EPRI Study conducted by URS Corporation, Interim Progress Report., In press.

3
ESTABLISHMENT OF COST RANGES AND CORRELATIONS

Information base for cost range and correlations

Independent estimates of the cost to retrofit a once-through cooled plant to closed-cycle cooling were obtained for 82 plants. These plants are listed in Appendix B, identified by the first three digits of their Plant ID Number (from the list of Phase II facilities in Appendix A) preceded by an "F" for fossil plants and an "N" for nuclear plants. The table in Appendix B also lists the plant/fuel type, plant size, circulating water flow, source water type, plant location, source of the cost estimate and the project cost expressed in March 2010 dollars. The March 2010 dollar costs are scaled from the amount and date of the original cost estimates using "Cost Construction Indices" as obtained from the Engineering News Record (3-1).

Figure 3-1 displays the capital cost of retrofits at the 82 plants vs. the circulating water flow rate. One plant (N-321) is a significant outlier and is so indicated on the plot. This plant is omitted from the development of the correlations because including it would distort the curve fit to the point where the other plants which represent a wide range of conditions would be poorly represented. It is important to note, however, that individual situations exist in which site-specific conditions make a cooling system retrofit extremely difficult, as was the case for Plant N-321. In such cases, the retrofit cost can be much greater than would be expected even for plants judged to be "Difficult" or "More Difficult". Other, although less extreme, examples are seen in Figure 3-1.

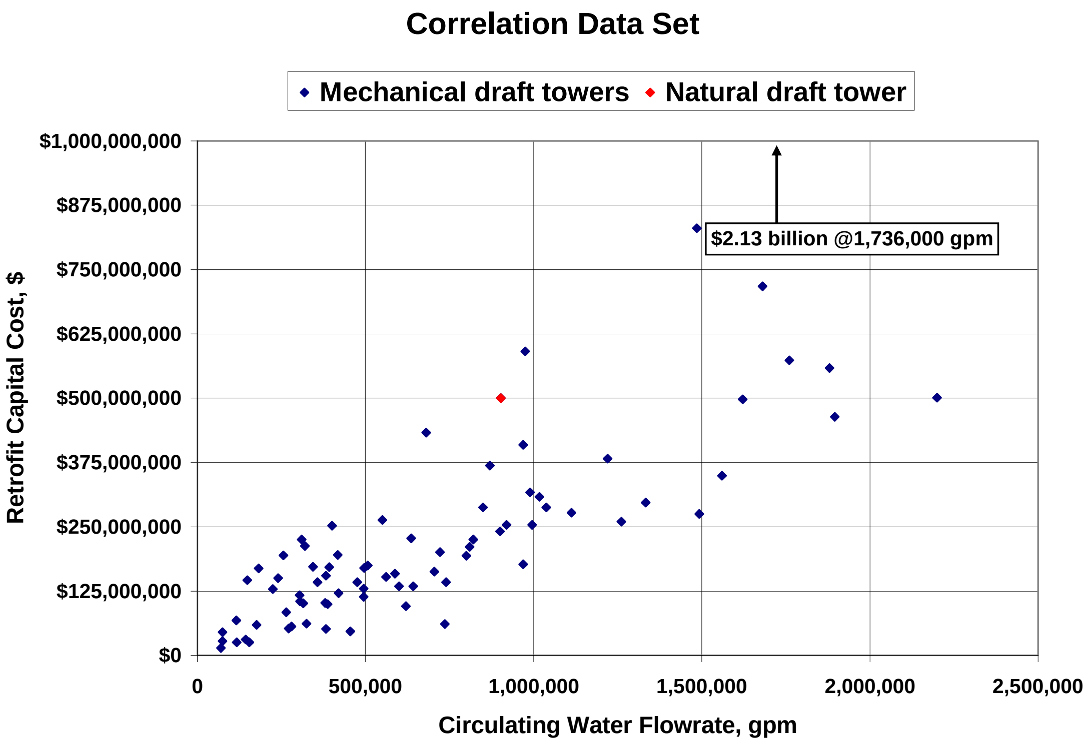

Figure 3-1
Plants with independent cost information

The 82 plants for which cost information is available break down into separate categories for nuclear and fossil plants and for fresh, brackish and saline source water and region of the country as tabulated in Tables 3-1 and 3-2.

Table 3-1
Distribution of Plant and Water Types for Plants Used in Correlations

Plants for Correlation Development			
Water Type	Fossil	Nuclear	Total
Fresh	38	4	42
Brackish	12	5	17
Saline	16	7	23
Total	66	16	82

Table 3-2
Regional Distribution for Plants Used in Correlations

Regional Distribution			
Region	Number of plants		
	Fossil	Nuclear	Total
Mid-Atlantic	7	4	11
Midwest	16	2	18
North Central	1	2	3
Northeast	9	4	13
Pacific	12	2	14
South Central	2	0	2
Southeast	19	2	21
Total	66	16	82

Analysis of data

The 82 capital cost data points were compared and analyzed from several viewpoints prior to the establishment of the correlating equations for the "degree of difficulty" categories.

Choice of scaling factor

In order to establish cost ranges for an individual plant, it is necessary to select a scaling factor with which to modify costs from known plants as a function of the size of the cooling system. A number of obvious possibilities exist including plant capacity, cooling system heat load or cooling water flow rate.

The correlations would not be expected to be equivalent since neither the heat load nor the cooling water flow rate is necessarily well correlated to plant output given significant differences in plant type, plant efficiency and cooling system design. Figure 3-2, for example, shows the wide variation in the circulating water flow normalized with plant capacity (gpm/MW) for the 82 plants. While the range of circulating water flows per unit of plant capacity is similar for both fossil and nuclear plants, the average circulating water flow for nuclear plants is over 20% higher than for fossil plants.

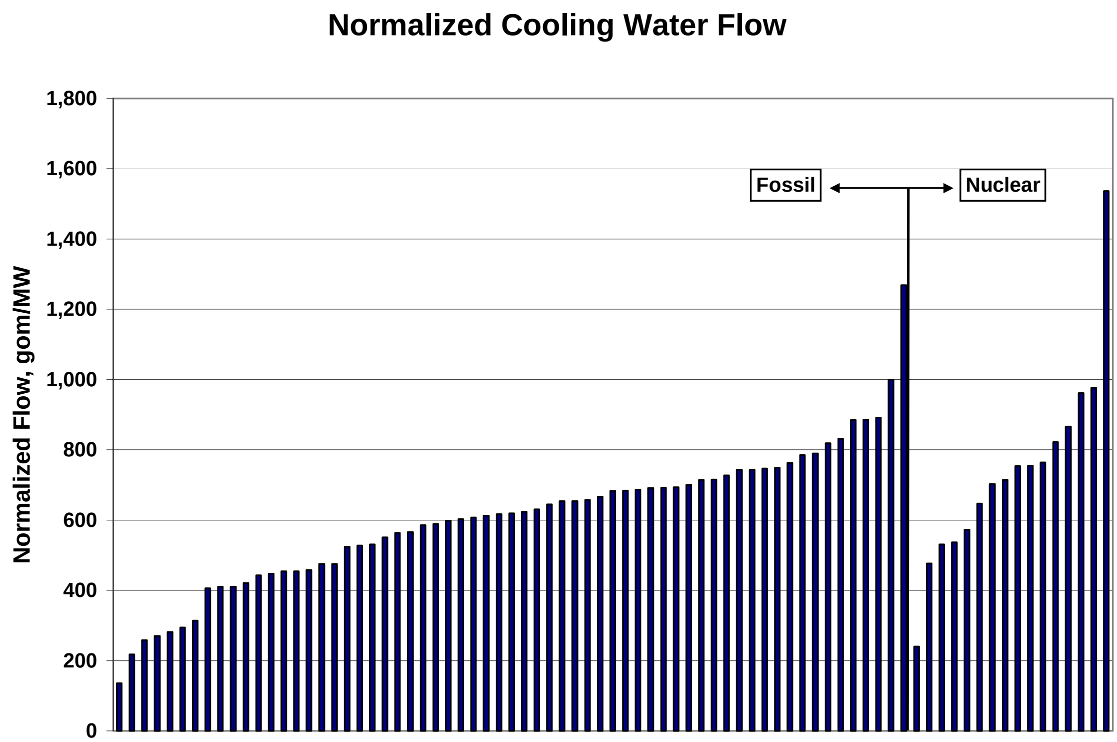

Figure 3-2
Normalized Cooling Water Flow Rate for Selected Plants

The circulating water flow was chosen to be the preferred scaling variable for several reasons:

1. Cooling system cost would be expected to be more closely related with water flow than with plant size (expressed in maximum output power in MW) given that the size of most of the important cooling system components (cooling tower, pumps, and piping) are primarily dependent on flow rate

2. Simple visual inspection of the data plotted against each of the three possibilities indicates a more consistent correlation with cooling water flow rate than with the others. Compare, for example, the plot of retrofit capital cost vs. plant capacity in Figure 3-3 with the plot against circulating water flow in Figure 3-4. While both exhibit considerable scatter, consistent with the site-specific nature of the projects, the cost range is greater and the outliers are more numerous in Figure 3-3. The correlation coefficient for a simple linear fit, while low in both cases, is significantly greater for the plot of retrofit capital cost vs. circulating water flow (R^2 = 0.67) than it is for the plot of retrofit capital cost vs. plant size (R^2 = 0.34).

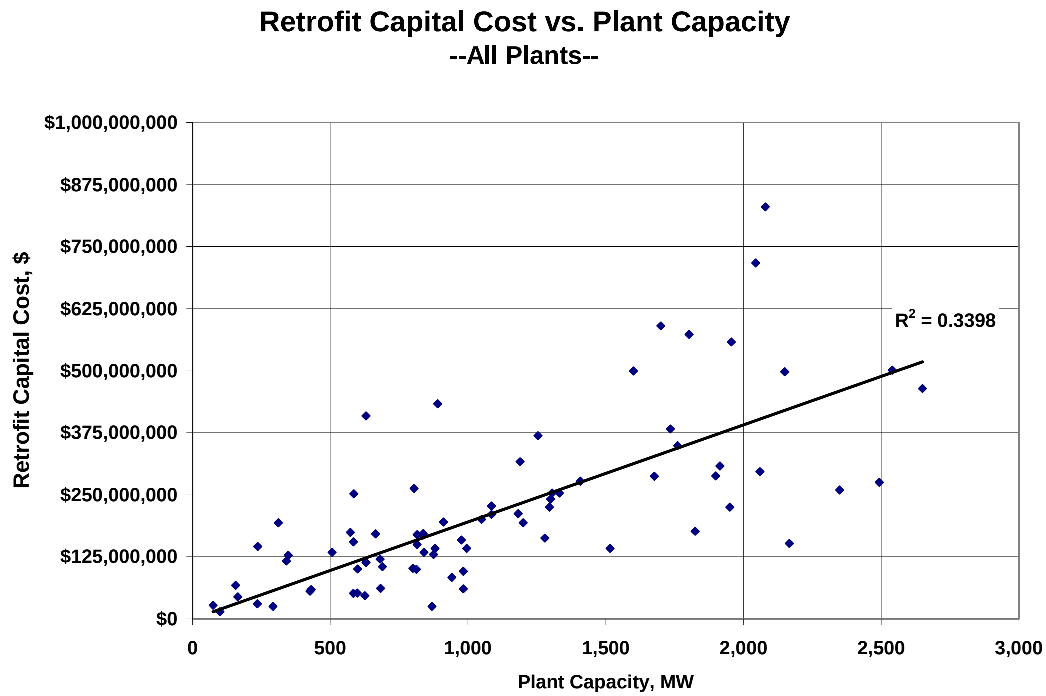

Figure 3-3
Retrofit Capital Cost vs. Plant Capacity

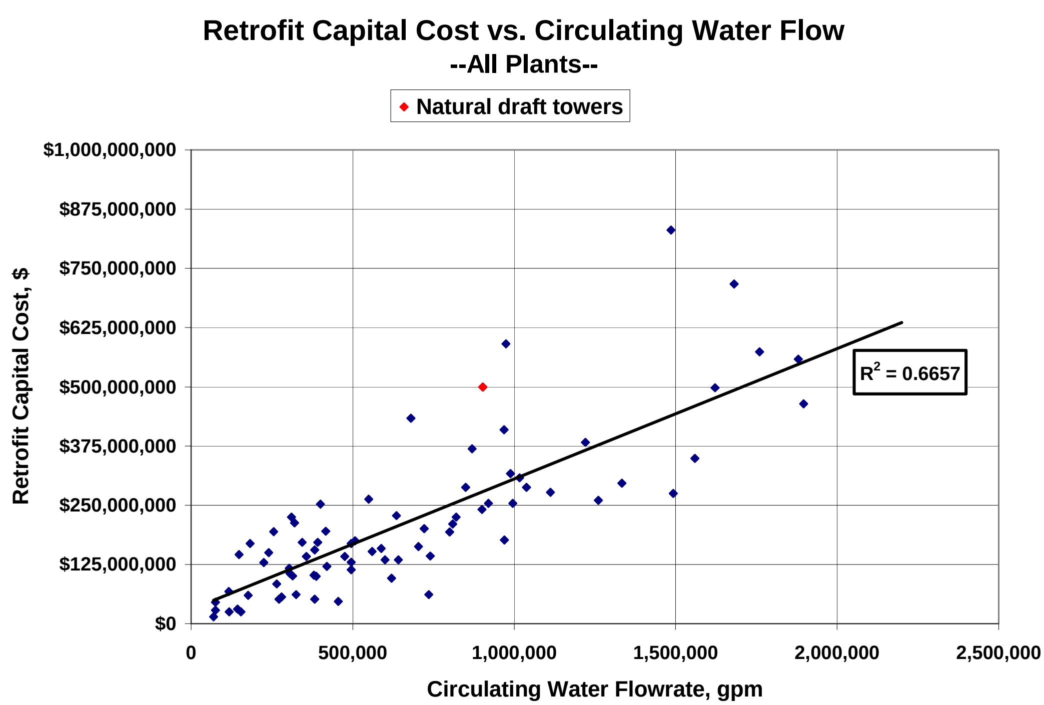

Figure 3-4
Retrofit Capital Cost vs. Circulating Water Flow

Effect of other factors

The costs displayed in Figures 3-3 and 3-4 are from plants of different types, drawing make-up water from sources of different water quality and located in different regions of the country. Also, the estimated costs were obtained from different information sources. Before specifying simple linear cost correlations for each degree of difficulty, the data are examined in more detail to determine whether different correlations are required for different plant types, water sources and regions and whether data from all sources present a consistent picture.

Fuel types----fossil vs. nuclear

Figure 3-5 displays the retrofit capital cost data for all plants, differentiated as fossil or nuclear plants vs. circulating water flow. While there is considerable overlap in the two data sets, important differences exist between the costs for the two plant types. The nuclear plant costs exhibit more scatter than the fossil plants and represent a large fraction of the highest cost projects across the entire range of circulating water flow rates.

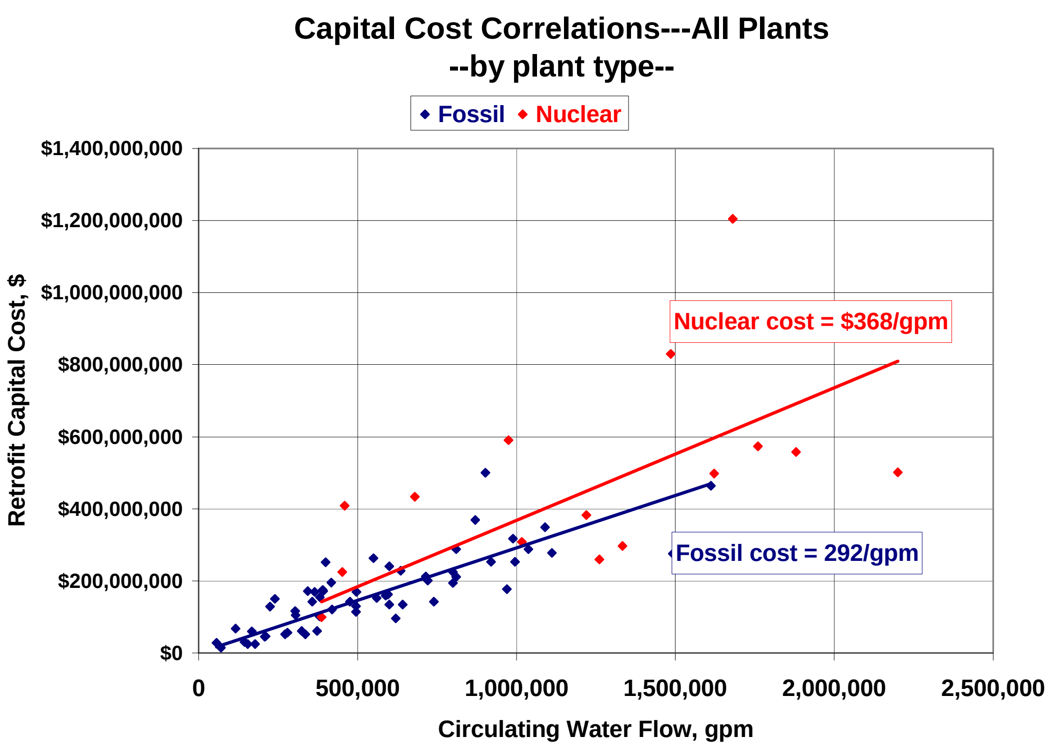

Figure 3-5
Retrofit Cost Data by Plant Type

This may be the result of several factors. The heat duty of the condenser cooling system for a given plant capacity (normalized condenser heat load in Btu/MWh) is greater for nuclear plants than for fossil plants for two reasons. First, nuclear plants operate at lower peak steam temperatures than do fossil plants and, as a result, have lower cycle efficiencies. Also, fossil plants reject a significant fraction of their waste heat through the stack whereas nuclear plants reject the entire waste heat load through the condenser. Therefore, in order to improve overall thermal efficiency, nuclear plants are typically designed with more efficient cooling systems and typically operate at higher circulating water flow rates on a gpm/MW basis. This generally requires, on the average, larger cooling system equipment for nuclear plants than for fossil plants of similar output.

The average cost of the nuclear power plants is approximately $368/gpm or about 26% higher than the $292/gpm average cost for fossil plants. Therefore, the correlations for fossil and nuclear plants were developed separately as subsequently discussed.

Fossil plant correlation development

Source water type

Figure 3-6 shows the cost vs. circulating flow data for fossil plants differentiated by source water: fresh, brackish and saline.

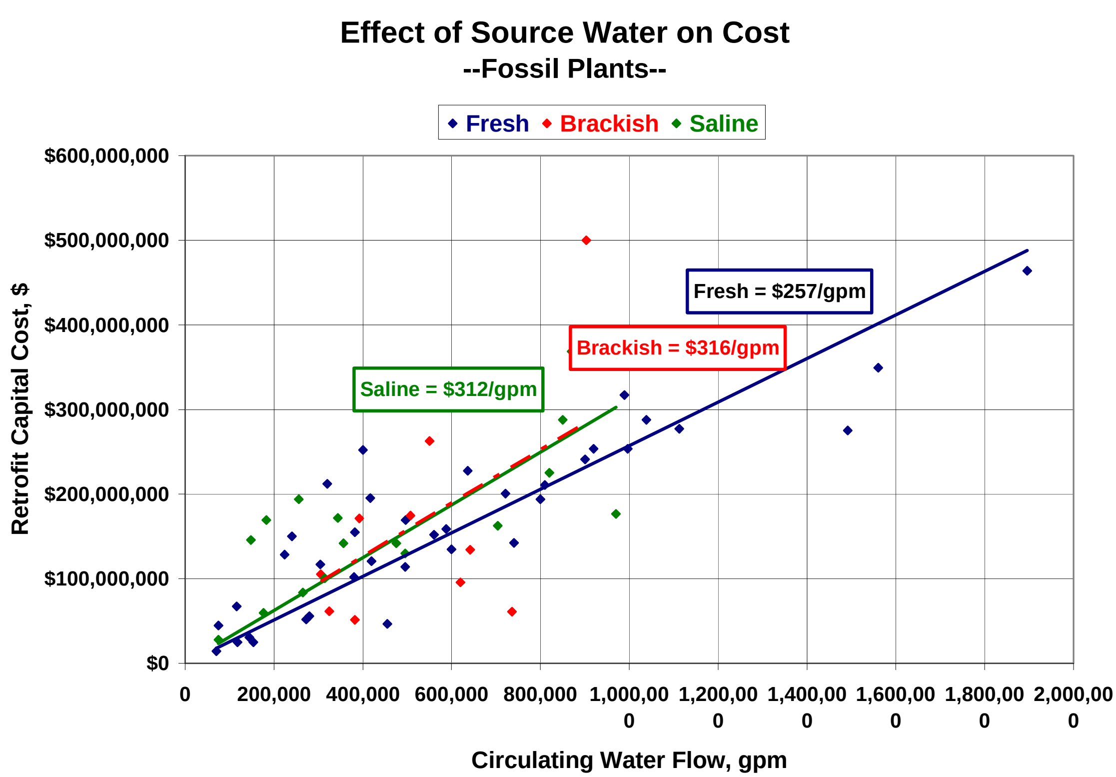

Figure 3-6
Effect of Source Water Type on Fossil Plant Retrofit Costs

Although cooling system components for saline water applications are typically more costly than those for freshwater applications (3-2), Figure 3-6 indicates that the average retrofit project cost difference between fresh and saline water plants is approximately 20%. While this is within the range of expected uncertainty of preliminary engineering estimates of major plant modification projects, it is also reasonably consistent with the results presented in the California Energy Commission report on salt water cooling towers (3-3). The difference in costs are attributable both to the requirement for a larger tower because of the lower evaporative cooling capability of salt water in comparison to fresh water and to the requirement for more expensive materials of construction to resist the corrosive nature of high salinity circulating water. The average brackish water costs are approximately the same as the average of the saline water plant costs.

Given the relatively small sample size for any single source water data set, the decision was made not to develop separate correlations for each. However, in the final cost estimate, after the degree of difficulty has been determined and the appropriate correlation applied, the resulting cost estimate for fossil plants on saline or brackish water will be increased by 20%.

Regions of the country

The plants included in the correlating set came from several regions in the country. The regions and the included states are presented in Figure 3-7. The states were grouped in regions in an attempt to aggregate sites where the differences between the original source water temperature, which sets the performance of a once-through cooled system, and the ambient wet bulb temperature, which sets the performance of a closed-cycle wet cooling system, would be similar. While these differences are not likely to have an important effect on the capital costs of retrofit, they will be an important factor in determining the performance differences and the corresponding energy and capacity penalties as discussed in Chapter 7.

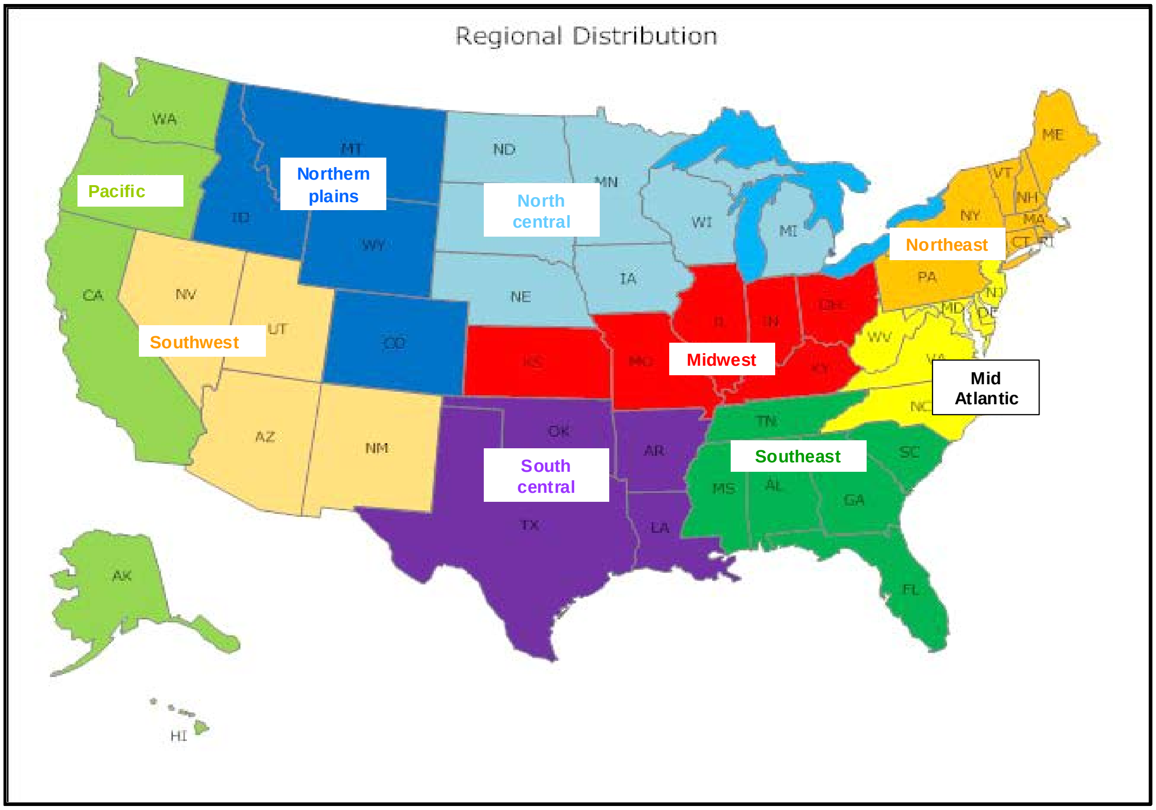

Figure 3-7
Geographical regions

The effect of location on the normalized capital cost of retrofit of fossil plants is shown in Figure 3-8.

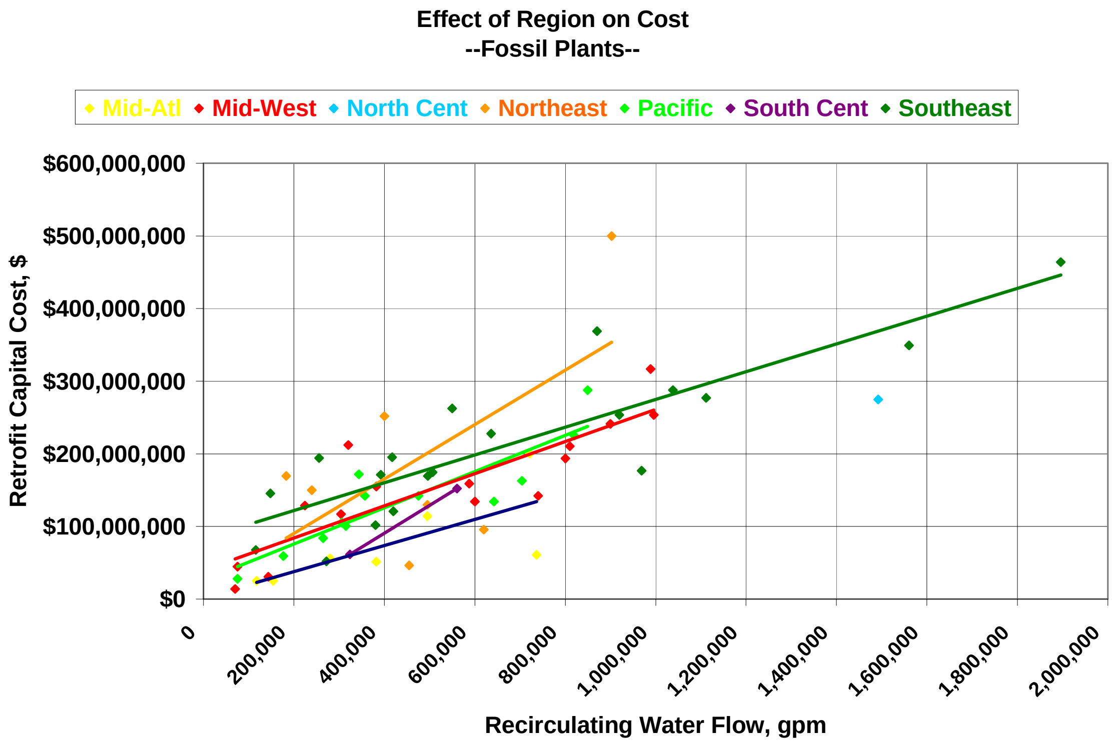

Figure 3-8
Effect of Location on Fossil Plant Retrofit Costs

There is no discernible systematic variation in the retrofit capital costs among the seven regions of the country displayed in Figure 3-8. The points at the high edge of the cluster are mainly points for coastal plants using salt water make-up in the Northeast, Southeast and Pacific regions. The freshwater plants from these same three regions are scattered more or less uniformly throughout the range. Therefore, the bias toward higher retrofit costs in these regions is attributed more to a preponderance of high salinity source waters than to any other "region-specific" factor.

<u>Data sources</u>

The independent cost information, in the form of retrofit capital costs for a number of individual plants, was obtained from several sources including:

Category 1: Individual utilities

Category 2: California study sponsored by the California Ocean Protection Council (3-3)

Category 3: EPRI 2002 utility survey and other sources (3-4)

Category 4: EPRI 2008 utility survey

Category 1: The most complete, detailed information comes from individual utilities which made data available from 9 plants at which closed-cycle cooling retrofits were either done or for which detailed, ”bid-quality” studies were performed by independent architectural and engineering firms with power plant design and construction experience.

Included in this category are **9** plants (Fos 1, N321, F275, Fos 2, F483, N218, N233, F546, Fos 5) for which complete, detailed cost information is available for essentially every equipment, material, labor and indirect element of the project cost. The cost for these plants are the ones in which the greatest confidence can be placed. In addition, an internal comparison of the cost elements sheds light on which elements of a retrofit are the most variable and which are most likely to cause a particular project to be more or less “difficult”. A listing of these plants and their relevant plant/site characteristics are given in Table 6-2. Detailed discussions of the cost information from each of these 9 plants and a comparison of their costs with the degree of difficulty ranges are contained in Appendix G. The results of the individual plant analyses are summarized in Chapter 6.

Category 2: A second category is a set of estimates for once-through cooled coastal plants in California. Although far less detailed than the Category 1 studies, these studies have the advantage that they were all performed by the same engineering firm ensuring a consistency of approach and careful attention to site-specific differences among nominally similar plants and sites.

Category 3: The largest category is made up of cost estimates assembled by EPRI in 2002 as part of a study conducted to develop comments for EPA’s then current 316(b) rulemaking (3-4). The estimates came from a variety of sources including individual utilities, a set of cases from data assembled by DOE in the 1990’s (3-5) and four individual case studies conducted by DOE’s National Energy Technology Laboratory (NETL) for EPA (3-6). The dates of the estimates and the level of detailed supporting information are highly variable.

Category 4: These estimates were recently obtained by EPRI as part of this current study through an industry-wide survey using the Cost Estimation Worksheet included in Appendix C. All are supported by studies conducted either by the utility’s engineering department or an independent engineering firm. The depth and detail of the supporting information is less than for the Category 1 studies and similar to the Category 2 studies. The advantage is that these studies are all relatively recent and have current design, performance data and cost information.

It is interesting to note that these Category 4 estimates often lie at the high end of the range. This may result from several factors. First, most of these estimates are relatively recent and are not subject to the uncertainties associated with scaling up costs from previous years. Second, these estimates invariably contain a significant “Contingency” amounting typically to 30 to 35%. Finally, in light of the fact that these estimates may become firm obligations, more conservative assumptions may have been used.

Figure 3-9 displays the fossil plant retrofit cost estimates differentiated by these categories.

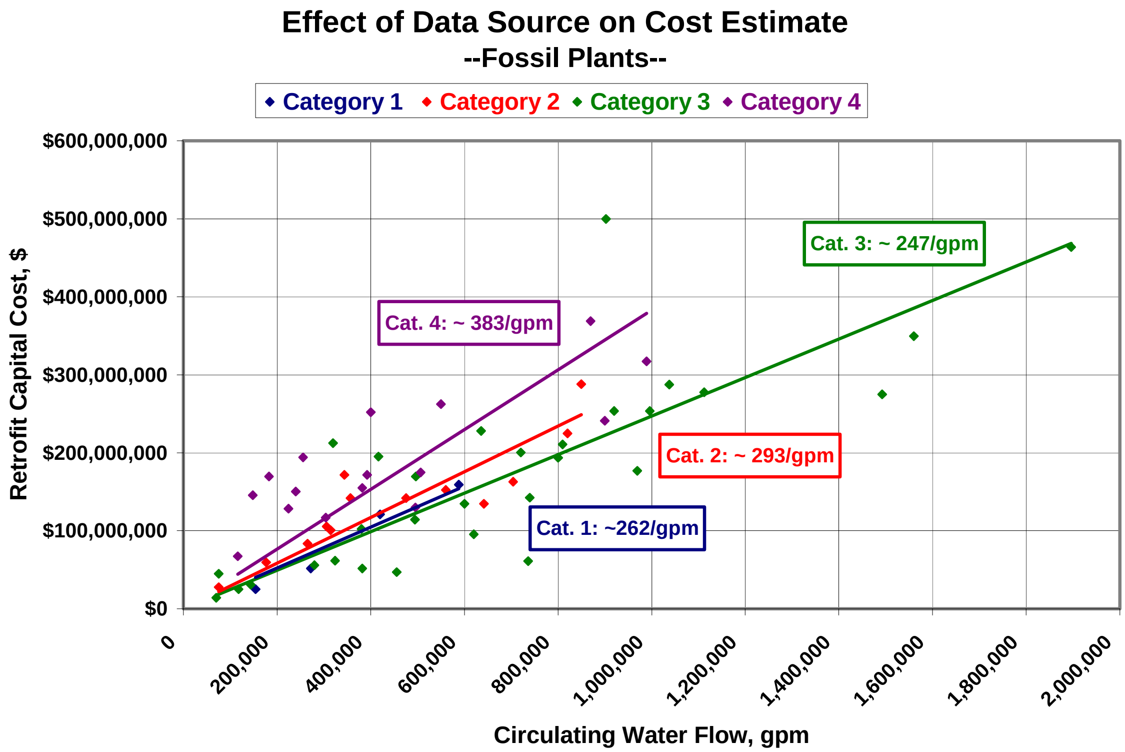

Figure 3-9
Fossil Plant Retrofit Costs by Data Source

The plot of the retrofit cost estimates in Figure 3-9 shows values from all categories spread across the entire cost range. Several observations are noteworthy.

1. In general, the points within each category show reasonable consistency. Category 3 exhibits the most scatter due in part to the greater number of points and to the fact they come from disparate sources as noted above.
2. Category 3 has the lowest average normalized cost. This may be due to the fact that, on average, the original estimates are older than those for the other three categories and the simple scaling relationships used to bring the costs up to 2009 equivalent costs may not capture all of the cost increases over many years.
3. Categories 1, 2 and 3 are in reasonable agreement with each other with a spread of less than +/-10%.
4. Category 4 is significantly higher than the others. This is likely due to several reasons. First, the estimates are the most recent. The estimates were conducted by experienced engineering firms with the objective of providing guidance to the plant owners in anticipation of a decision of whether or not to retrofit. This likely resulted in more detailed scrutiny and perhaps more conservative assumptions and higher contingencies than was the case for the other categories.

5. Category 1 is perhaps surprisingly low since it represents both actual retrofits and detailed studies. However, the number of cases is small and, coincidentally, four of the six fossil plants in this category were judged to be "easy" retrofits for which comparatively low retrofit costs would be expected.
6. Finally, the number of cases in each category is small and some of the differences may be due simply to statistical aberrations. Given the good distribution of estimates from all categories across the range of circulating water flows and costs no distinctions will be made in the correlations on the basis of the source of the individual data points.

Fossil plant capital cost correlations

Figure 3-10 shows the costs for the fossil plants arranged in increasing order of the normalized retrofit costs ($/gpm).

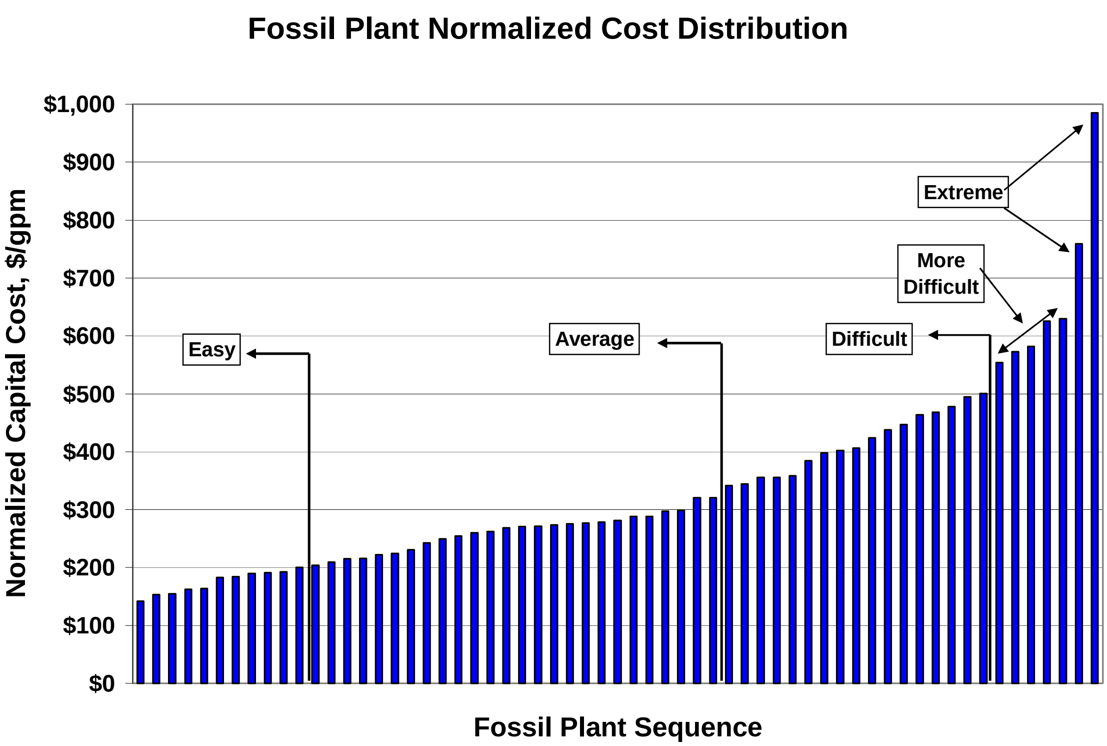

Figure 3-10
Categorization of Fossil Plant Costs by Degree of Difficulty

Figure 3-11 displays the fossil plant data with the correlating lines superimposed on the plot. The division between the categories is somewhat arbitrary. There are no distinct "break points" at most of the lines of demarcation, but the average cost estimated for each of the three categories are distinctly different, and the variation from the average within each group is modest. In the interest of keeping the number of categories to a minimum in order to get a reasonable sample size in each group, the choice of "round number" costs as the dividing lines was made. Different choices as to the groupings would not be expected to have any important effect on the eventual national cost totals.

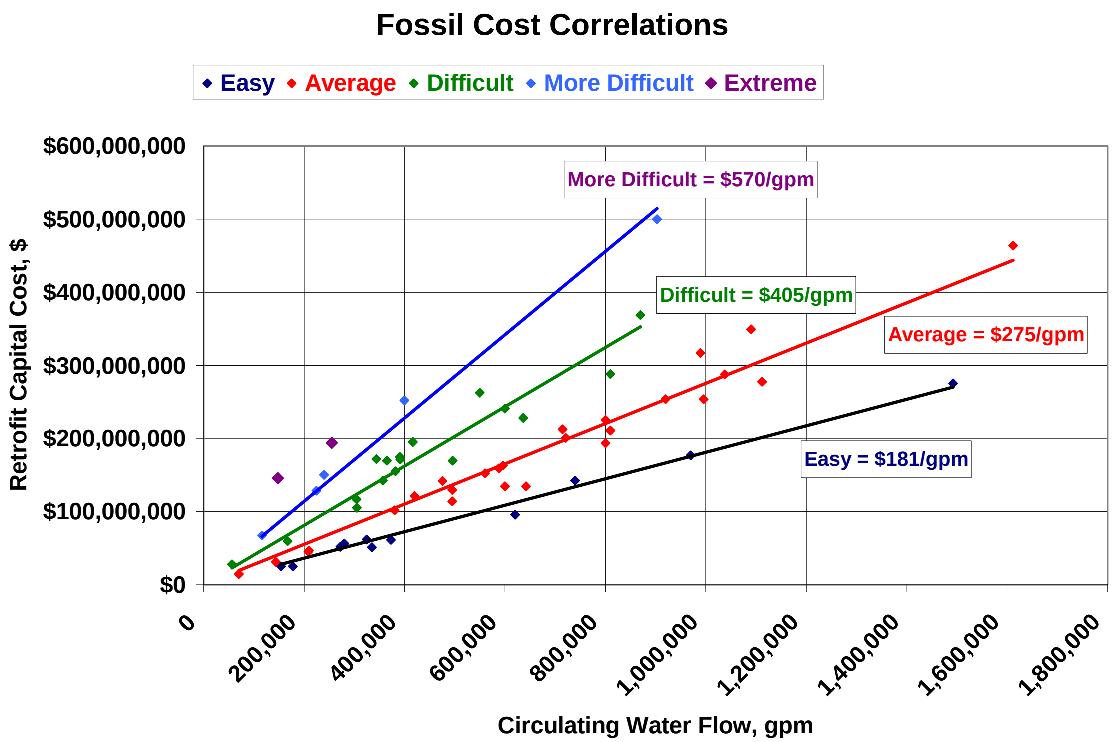

Figure 3-11
Fossil Plant Retrofit Capital Cost Correlations

The coefficients in the linear correlating equations for the four degrees of difficulty for fossil plants are:

Easy:	**$181/gpm**
Average:	**$275/gpm**
Difficult:	**$405/gpm**
More difficult:	**$570/gpm**

Nuclear plant correlation development

As seen in Figure 3-5, the cost estimates for nuclear plants are far fewer in number than those for fossil plants, but they exhibit greater variability. Before developing correlations for nuclear retrofits, the effects of source water quality and data source were examined.

Nuclear plants—effect of source water type

Figure 3-12 shows the nuclear plant retrofit costs differentiated by source cooling water type. Although the small number of plants and the significant amount of scatter in each category makes comparisons difficult, the average of the costs for the saline plant retrofits is about 15% higher than that for the fresh water nuclear plants. This is reasonably consistent with the 20%

difference observed in the fossil plant data. However, unlike the fossil plants where the saline and brackish water plant costs agreed well, the brackish water plant costs for the nuclear plants average about 20% less than the fresh water plants.

Since the characteristics of brackish water are nominally intermediate between saline and fresh water characteristics, there is no immediately apparent reason for this difference. It is, therefore, assumed that the difference is a statistical aberration due to the small sample size or that these plants are, on average, slightly less difficult retrofits than the bulk of the nuclear sites for reasons having little or nothing to do with the quality of the make-up water. Therefore, no differentiation among source water types will be made for nuclear plants and no adjustment is made for the brackish plants.

There is a consistent result that retrofit costs for plants with saline water make-up are higher than for plants on fresh water make-up for the same cooling system circulating water flow rate. The difference, however, of approximately 15 to 20% is felt to be within the level of precision of the correlation given the paucity of data points and the scatter among them. Therefore, the cost range for nuclear plant retrofits will be established without reference to source water type. However, as was discussed in the section on fossil plants, the determination of the degree of difficulty will be made on all the other factors and then an upward adjustment of 20% will be made for plants with saline make-up.

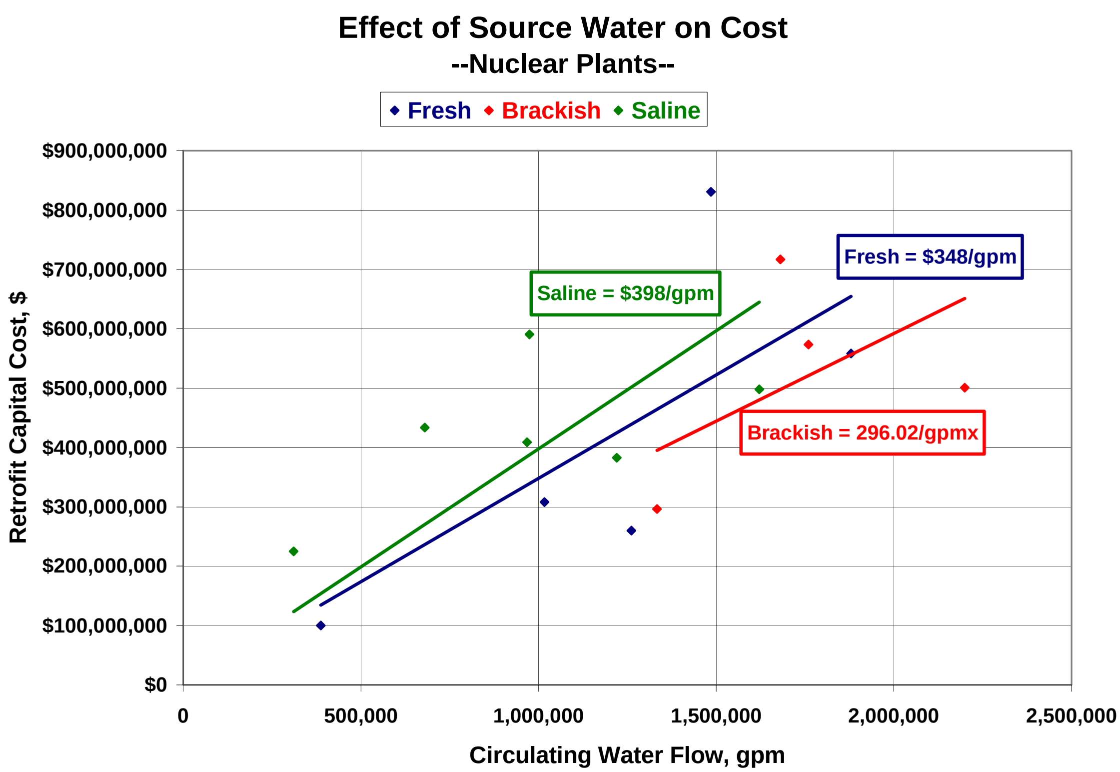

Figure 3-12
Effect of Source Water Type on Nuclear Plant Retrofit Costs

Regions of the country

As was the case for the fossil plants, the nuclear plants included in the correlating set came from several regions in the country. The effect of location on normalized capital cost of retrofit of nuclear plants is shown in Figure 3-13.

While there is considerable scatter, there is no discernible separation by region and no differentiation, therefore, is made among the nuclear plants on a regional basis. As was the case for the fossil plants (Figure 3-8), the highest points are associated with oceanside plants with seawater make-up and not with any other region-specific factors.

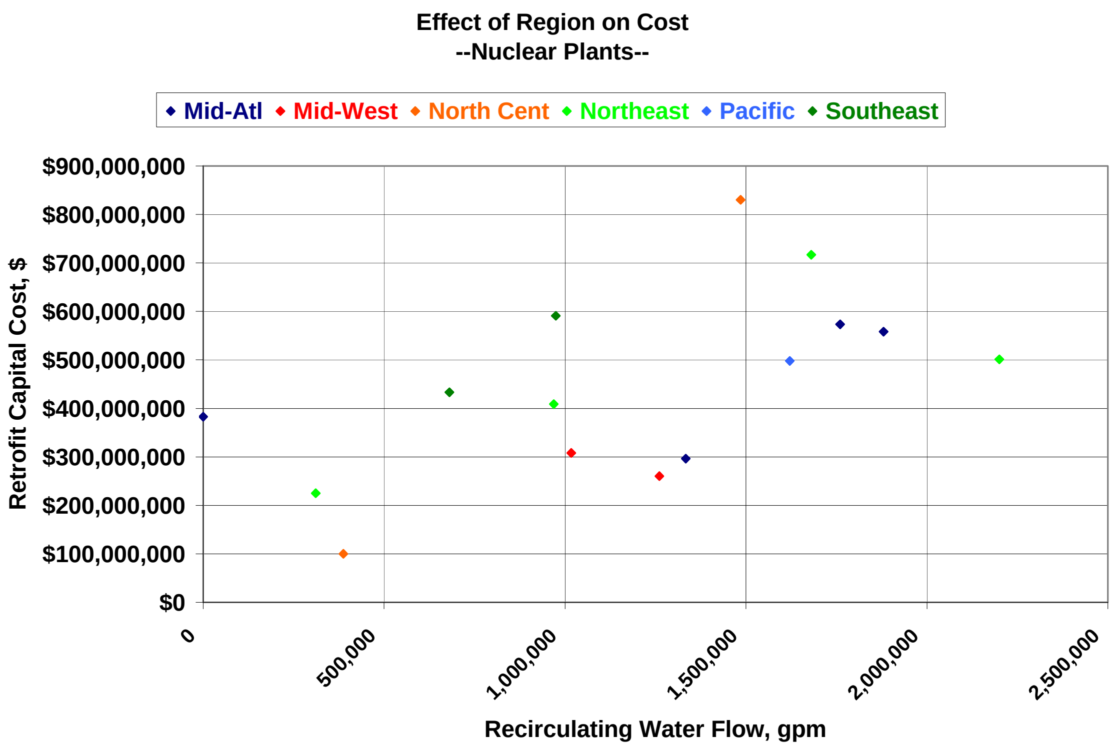

Figure 3-13
Effect of Location on Nuclear Plant Retrofit Costs

Nuclear plants—effect of data source

Figure 3-14 presents the nuclear plant retrofit costs differentiated by the source of the data. The categories are the same as those described for fossil plant cost estimates in the previous section. Only Category 3 contains more than 2 plants. Therefore, the statistical uncertainty in the linear fits for Categories 1, 2 and 4 is high, and no conclusions were drawn from this comparison of sources. It is simply assumed that the high cost points represent plants of a more difficult retrofit situation and will be included in the nuclear correlations displayed in Figure 3-16. In the case of nuclear plants, the source of cost estimates makes no difference to the magnitude of the estimated costs.

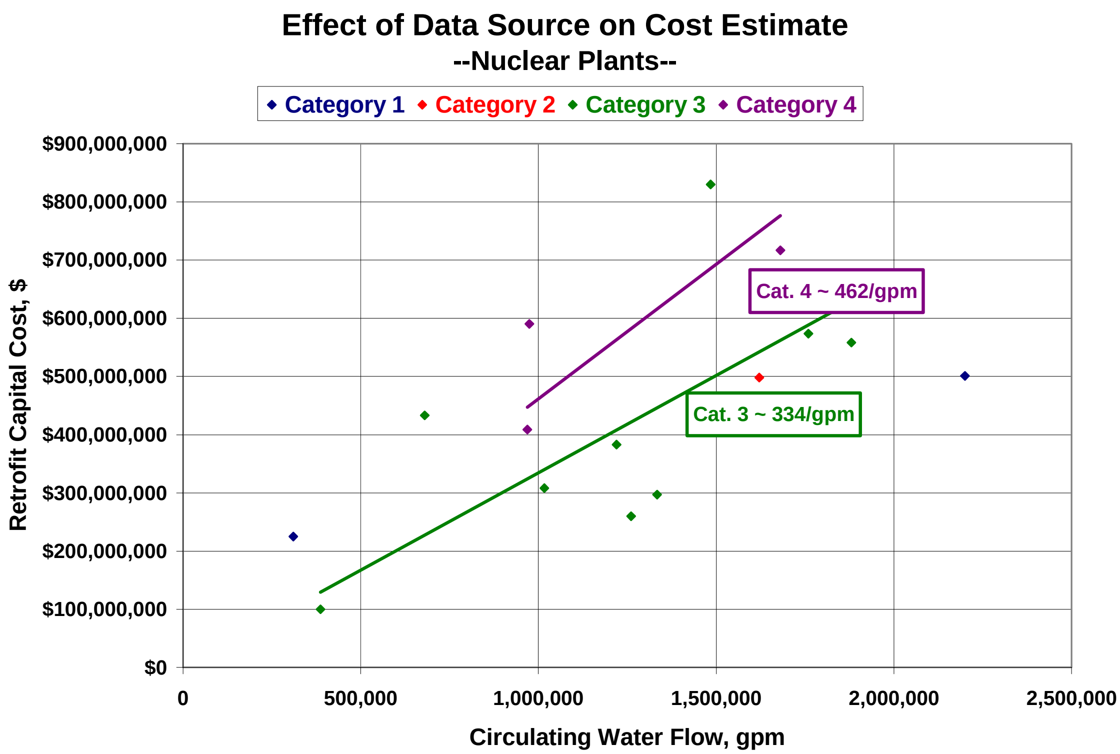

Figure 3-14
Effect of Data Source on Nuclear Plant Retrofit Costs

Nuclear plant correlation development

The small number and large variability of nuclear plant cost estimates makes it impossible to create precise estimates of the average cost/gpm for the four distinct categories (Easy, Average, Difficult, More difficult) as was done for the fossil plants. The approach taken was to rank the nuclear plant costs estimates by normalized cost as shown in Figure 3-15. The costs for plants 1 through 9 were identified as "Less Difficult" and plants 10 through 15, as "More Difficult." Point 16 (N-321) was referred to earlier as a significant outlier and is not included in the development of the correlating equation. While the selection of a line of demarcation is a matter of judgment, a slight breakpoint does appear between plants 9 and 10. The separation of the estimates into these two categories, along with the selected correlation lines, is shown in Figure 3-16.

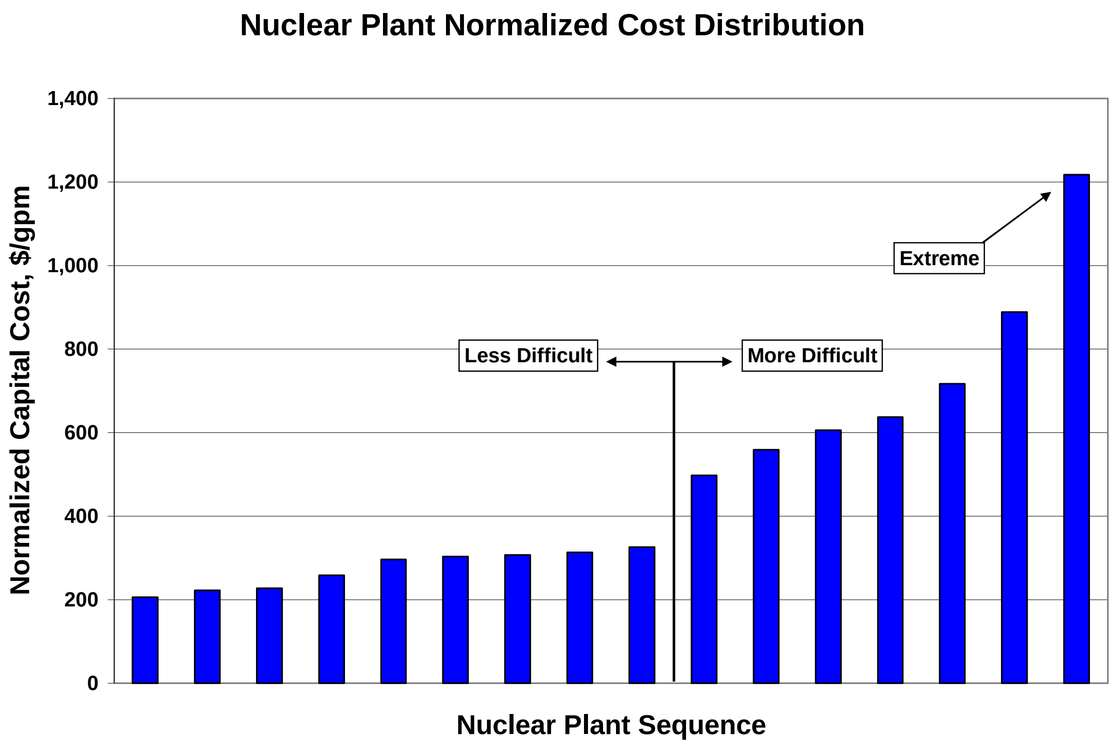

Figure 3-15
Normalized Cost Estimates for Nuclear Plant Retrofits

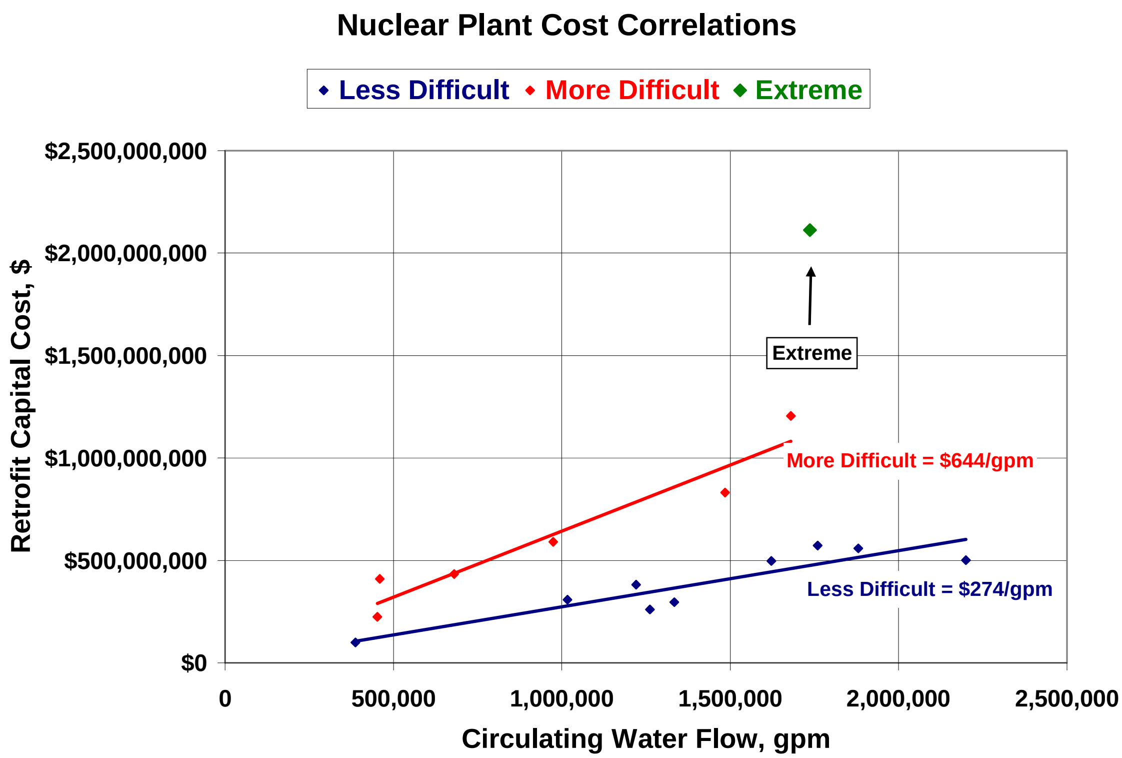

Figure 3-16
Correlations for Nuclear Plant Capital Cost Estimates

The coefficients in the linear correlating equations for nuclear plant retrofits are:

"Less difficult": $274/gpm
"More difficult": $644/gpm

Observations on correlating equations

Examination of Figures 3-11 and 3-16 shows that the correlating equations are simply linear fits to clusters of data representing the costs of retrofit projects at individual plants. These costs, for any particular circulating water flow rate, range from low to intermediate to high or "very high". The assertion that these cost ranges are attributable to site-specific features which influence the "degree of difficulty" of an individual retrofit project at a given plant is the basic hypothesis underlying the methodology used in this study. The usefulness and validity of this hypothesis will be illustrated through the examination of a group of individual plants for which site-specific information has been obtained (Chapters 4 and 5) and the assignment of a degree of difficulty to each plant. Where possible, the resulting cost estimates will be compared to independently obtained cost estimates as a partial validation of the methodology (Chapter 6).

Finally, it is clear that the cost estimates do not represent "bounds" on the costs of individual retrofits. That is, there are cases where the costs are less than what the "Easy" correlation would give and cases which are higher, sometimes significantly so, than the cost that would be obtained from the application of the “Difficult” or “More Difficult” correlation. Therefore, they are in no sense a “prediction” of the cost for any individual plant but rather an indication of the likely range of cost to be expected for a plant of a given circulating water flow rate.

Chapter 3 References

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4
ESTABLISHMENT OF DEGREE OF DIFFICULTY

Site-specific information

In order to develop an estimate of the retrofit cost for a specific plant, it is necessary to estimate the degree of difficulty of retrofitting the cooling system at the site in order to determine where in the range of costs developed in Chapter 3, the plant would be expected to fall. Nationwide, there are approximately 428 plants (389 fossil; 39 nuclear) classified as Phase II facilities (Appendix A).

As part of this study, site-specific information on the generating units, the cooling systems and the site characteristics was requested from the Phase II facilities. This was accomplished by distributing a cost estimation worksheet to all the member companies of five major utility organizations including the Utility Water Act Group (UWAG), the Edison Electric Institute (EEI), the National Rural Electric Cooperative Association (NRECA) and the American Public Power Association (APPA) as well as EPRI itself.

The information solicited covered the following subject areas:

Items related to the degree of difficulty and capital cost determination include:

- General descriptive information for the plant and for each unit
  (location, capacity, water flows, source water type, fuel, year on-line, etc.)
- Site characteristics
  (plot plan, boundaries, elevation profiles, structures, underground utilities, geology)
- Neighborhood characteristics
  (general character [rural, urban, suburban, industrial, commercial], nearby residential areas, schools, churches, roads, airports, etc.)
- Alternate water sources
  (source type, distance from source to plant, applicable regulations on use)

Additional items for estimating additional power costs and efficiency/capacity penalties include:

- Site meteorological data
  (source water temperatures, dry and wet bulb temperatures)
- Cooling system design characteristics
  (condenser specifications, turbine heat rate curves)

- Unit operating profiles
  (load scheduling, outage times)
- Plant economic factors
  (fuel costs, power price)

On the basis of information provided, the questionnaire spreadsheets automatically calculated the following quantities:

- Probable range of retrofit capital costs
  (Easy, Average, Difficult and More Difficult for fossil plants; Less Difficult and More Difficult for nuclear plants)
- Cooling tower size
  (Number of cells, footprint dimensions, height)
- Additional operating power costs
  (Fan and pump power)
- Capital and annualized retrofit cost summary

Responses were received from 185 plants. The information obtained was intended to permit the evaluation of the factors most relevant to establishing the site-specific degree of difficulty that were introduced in Chapter 2 in Table 2-1.

These factors are discussed in more detail below.

Important Plant /Site Characteristics

Item 1--Tower location: Plant sites vary widely in the amount of open space available within existing site boundaries, and cooling towers require a large amount of space. A recent retrofit at a 550 MW coal-fired plant in the southeastern U.S. required the installation of a 40-cell tower with a footprint of approximately 1,000 by 100 feet. This tower was erected in a back-to-back arrangement. If plume abatement had been required, an in-line arrangement would have been necessary, requiring a much longer open area for a single tower or a much wider one if two separate towers had been chosen. Additional requirements, such as the need to align a tower lengthwise with the prevailing winds in order to avoid recirculation, can further limit the available options for siting the towers. Towers can often not be sited near switchgear if there is concern that drift deposition may coat the surface of insulators with conductive salts and lead to a breakdown of the insulating capability. In some situations, the installation of a cooling tower can necessitate the re-arrangement or demolition and relocation of existing structures to make room on the site for the tower.

If no space is available within existing boundaries, the only remaining option would be to purchase adjoining land, if available, at indeterminate cost. The lack of space on the existing site will be considered to make a closed-cycle retrofit infeasible.

Item 2--Separation distance: In some instances, the only available location for a cooling tower is far removed from the turbine building and condenser. While for new plant construction most towers are placed within a few hundred feet of the turbine building, in retrofits, separation distances of 1,000 feet or more may be required. As will be discussed in Items 3 and 4, the increased separation distance, in addition to increasing the material and labor cost of installing the circulating water lines and the required pumping power, also increases the likelihood of encountering unfavorable or confounding geologic conditions or additional interferences (e.g., pipes and other interferences as discussed in item 4 below) which can add greatly to the difficulty of the project.

Item 3--Unusual site preparation requirements: Site problems which are known to significantly increase retrofit costs are:

- The presence of saturated unstable soils for which extensive damming, drainage or the installation of pilings are required in order to provide a stable platform for the cooling tower
- The presence of bedrock which requires costly drilling or blasting in order to install underground circulating water lines
- The presence of contaminated soils with associated costly handling and disposal requirements
- The presence of known archeological artifacts or threatened and endangered species protection requirements.
- The presence of protected habitats or sensitive areas, such as wetlands.

Item 4--Underground interferences: This is a common cause of difficulty in retrofit projects. Existing plant sites are often underlain with numerous runs of piping, electrical lines, power buses, storage tanks and communication lines. In a recent project in northern California, the routing of new circulating water lines across the existing plant site encountered nearly 200 separate interferences over a distance of about 1,500 feet, increasing the installation cost of the lines by nearly a factor of five.

Item 5--Condenser/tunnel reinforcement: In some situations (See, for example, #2 below), there will likely be a need for condenser and tunnel reinforcement. This depends on how the cooling tower circulation loop is tied into the existing once-through cooling loop. Two general approaches can be taken.

1. In some cases, the existing condenser and circulating water pumps are left essentially undisturbed. The circulating water is pumped through the condenser as before, but the discharge line, instead of returning to the source waterbody, is re-routed to a sump. A new set of circulating water pumps is installed. These pumps draw from the new sump and pump to the hot water distribution deck on top of the cooling tower. Cold water from the tower basin then returns by gravity to the existing inlet bay. This may require grading the site for the tower to provide sufficient elevation to enable the gravity return. In this case, the condenser and the existing water tunnels see the same flows and pressures as before, and no modification is required. However, the location of a sump of adequate size can be a problem and a costly part of the installation at some sites. In a case where it may be impossible to

locate a tower at an elevation higher than the condenser, it would be necessary to pump the cold water back to the condenser. This may require an additional set of pumps.

2. An alternative approach is to replace the existing circulating water pumps with pumps of higher head, which pump the water through the condenser and then to the top of the tower. This can double, or more than double, the pressure in the condenser waterboxes and the existing inlet and discharge tunnels. In this case, condenser waterbox and perhaps tube sheet stiffening will likely be required and tunnel reinforcement, sometimes by lining the existing tunnels with steel pipe, may be necessary.

Item 6—Plume abatement: The discharge of warm, saturated air from the cooling tower can produce a large visible plume when it mixes with cooler ambient air under some atmospheric conditions. This plume can be unacceptable in some situations such as, for example, if it were to create visibility problems on a nearby highway or for an airport. Even in the absence of safety considerations, it may be unacceptable on aesthetic grounds to nearby residential communities, recreational areas or scenic viewsheds. In such cases, plume abatement may be required in order to obtain permits for the tower. While plume abatement designs exist, they are nearly three times the cost of a conventional tower (4-1) and, as noted above, require in-line tower arrangements which can further complicate the siting of a tower on a congested site.

Item 7---Drift: In addition to visible plumes, cooling towers continuously emit a small amount of liquid water entrained in the discharge air as very small droplets, known as drift. While state-of-the-art, high performance drift eliminators can reduce the drift rate to a very low level (<0.0005% of the circulating water flow), it cannot be eliminated entirely. Depending on the quality of the cooling tower make-up water and the cycles of concentration at which the tower is operated, the drift will contain varying amounts of dissolved solids. The drift salinity will be the highest from towers using make-up water of high salinity from oceans, estuaries and tidal rivers.

The deposition of drift on the plant site can lead to increased maintenance requirements if it falls on structures, vehicles or switchyard equipment. Additionally, the presence of “sensitive receptors” (e.g., hospitals, senior citizen facilities, sensitive crops, schools, historic areas, dense population areas) close to the site boundary may lead to serious objections to the permitting of a tower at the site, and no technological solution exists to eliminate the problem. In such cases, a retrofit to closed-cycle cooling with wet cooling towers would likely be deemed infeasible.

Item 8—Noise reduction: Mechanical draft cooling towers produce continuous noise both from the fans and from the water falling through the fill and into the basin. Typical sound levels are about 70 dBa at a distance of 50 feet from the tower. This is not normally a problem within the plant boundaries. However, if the tower is located near the plant boundary, there may be sensitive receptors close to the plant, such as residences, places of worship, hospitals, senior citizen facilities and schools. There also may be noise ordinances that require meeting specified noise limits within a certain distance from the property boundary. In this case, sound barriers or inlet/outlet sound attenuation equipment may be used, but at a substantial increase in cost. (4-2)

Item 9--Alternate water sources: Under some circumstances, the source of cooling water which had been used for once-through cooling may be undesirable for use as make up to a closed-cycle cooling system. One example would be the use of seawater for once-through cooling of coastal plants, where high salinity drift or fine salt particles (potentially PM10) would be created by a cooling tower operating with seawater make-up. An option in this case might be the use of alternate sources of cooling water such as, for example, waste water from neighboring municipal water treatment plants, agricultural irrigation drainage or produced water from oil and gas or mining operations. This choice usually requires the installation of long-distance supply pipelines from the alternate source water location to the plant, and possible treatment prior to use of the water to reduce corrosion, fouling or scaling problems or to address issues of wastewater disposal. These approaches can add considerably to the difficulty and hence cost of the retrofit project.

Item 10--Related modifications to balance of plant: Many plants use the same intake facilities that are used for the once-through cooling system for intake to their auxiliary cooling systems and other water needs. To the extent that these systems have been sized on the basis of expected cold water temperatures, the systems may not operate satisfactorily on cold water return from a cooling tower during some portions of the year. This may require either a redesign of the plant inlet water facilities or the redesign and refurbishment of the auxiliary cooling water system to accommodate the altered operating conditions on closed-cycle cooling.

In some plants, cooled condensate from the primary steam cycle has been used for generator cooling. Condensate leaving the condenser is passed through a heat exchanger cooled with cold-side cooling water and thence to the generator cooling passages. The closed-cycle retrofit will lead to higher condensing temperatures during summer months, and the condensate cooler may not be of sufficient size to provide low enough temperature water to the generator. This would require additional modifications to this auxiliary cooling loop of unknown cost and complexity.

Additional considerations may include the provision of additional on-site electrical power and motor control facilities for the tower fans and water treatment and other maintenance facilities for the treatment of cooling tower make-up and blowdown, if required.

Item 11---Re-optimization of the cooling system: An important consideration in cooling system retrofits is whether the entire cooling system should be re-optimized to account for fundamental performance differences between once-through and closed-cycle cooling. In brief, closed-cycle cooling systems optimize at a lower flow rate and a higher cooling water temperature rise than do once-through cooling systems. Therefore, simply inserting a cooling tower into an existing once-through cooling loop results in a less effective and more costly cooling tower and higher operating power requirements than would be the case for a properly optimized closed-cycle cooling system. Re-optimization would normally significantly reduce the circulating water flow rate which, in turn, would require major modifications to the existing condenser, circulating water pumps and piping. Re-optimization should be considered as part of a retrofit for plants with high capacity factors and long remaining life, as is normally the case for nuclear plants. This subject and the effect on retrofit costs will be discussed in greater detail in Chapter 5.

Additional issues

Item 1—Outage time: While the cost resulting from a prolonged outage is not a capital cost, it is, nonetheless, an important cost due to the loss of revenue from these units and is related to the extent and complexity of the retrofit. Although much of the installation of the cooling tower and the circulating water piping typically can be done while the plant is on-line and operating on its existing cooling water system, the final tie-in of the new circulating water lines to the condenser inlet and discharge tunnels requires that the plant be shut down. An additional factor may be a need to relocate essential structures and plant facilities in order to make space for the tower. In some instances, the plant would be inoperable while those facilities were being changed over. This is particularly important if the cooling system is to be re-optimized, since this normally requires extensive modification or removal and replacement of the condenser and the associated piping.

A thorough investigation of these factors and estimates of the time required to accomplish them at various plants are beyond the scope of this study. However, it is noted that the outage durations at some moderate size fossil plants have been from 2 to 3 months. Estimates of the outage duration at some large nuclear plants have been as long as one to two years (due, in part, to the more likely need to re-optimize cooling systems at nuclear plants as discussed earlier (4-3, 4-4).

Item 2—Permitting: The installation of cooling towers at existing plants will require the application for and granting of new permits related to aqueous discharge of tower blowdown, drift emissions, noise and visual impact or possible sensitive habitat loss in most instances. The time and effort involved in these permitting procedures can be expected to add a significant amount to both the cost and the duration of the retrofit effort, but no information is available to estimate their magnitude. The inability to obtain such permits can prevent a retrofit project from proceeding.

Item 3:---Requirements specific to nuclear facilities: Important modifications to nuclear facilities are subject to extensive review and approval by the Nuclear Regulatory Commission (NRC). This includes not only design and operating safety considerations, such as maintaining an adequate cooled supply of water for the ultimate heat sink, but also issues related to plant security. For example, the secured perimeter of the plant may need to be extended to include the location of the cooling towers if they must be sited outside the existing secured perimeter. This may require the installation of additional monitoring equipment and the possible requirement for more security staff. All of these issues would require obtaining the necessary approvals from the NRC before proceeding. As in the case of the local permitting requirements discussed above, the cost and effort of obtaining this approval is indeterminate but can be expected to add important difficulty and associated cost to the effort.

Site-specific analyses

Information was received from 185 plants, listed in Appendix D. Tables 4-1 through 4-5 show the distribution of both the entire family of Phase II facilities and the 185 facilities for which cost estimation worksheets were returned among several categories of plant size, fuel type, source water, and location by region. The tables confirm that the set of worksheets obtained are a reasonable representation of the complete family of Phase II facilities.

Table 4-1
Worksheet distribution by plant type vs. Phase II population

Plant Type Distribution				
Plant Type	Phase II Facilities		Spreadsheets	
	Number	%	Number	%
Fossil	389	90.9%	166	89.7%
Nuclear	39	9.1%	19	10.3%
Total	428	100.0%	185	100.0%

Table 4-2
Worksheet Distribution by source water vs. Phase II population

Source Water Distribution								
Plant Size, MW	Fossil				Nuclear			
	Phase II Facilities		Spreadsheets		Phase II Facilities		Spreadsheets	
	Number	%	Number	%	Number	%	Number	%
Great Lakes	42	10.8%	17	10.2%	6	15.4%	5	26.3%
Lakes and Reservoirs	71	18.3%	25	15.1%	12	30.8%	2	10.5%
O/E/TR*	102	26.2%	53	31.9%	13	33.3%	11	57.9%
Rivers	174	44.7%	71	42.8%	8	20.5%	1	5.3%
Total	389	100.0%	166	100.0%	39	100.0%	19	100.0%

*Oceans, estuaries and tidal rivers

Table 4-3
Worksheet distribution by water quality vs. Phase II population

Water Quality Distribution								
Source Water	Fossil				Nuclear			
	Phase II Facilities		Spreadsheets		Phase II Facilities		Spreadsheets	
	Number	%	Number	%	Number	%	Number	%
Fresh	287	73.8%	113	68.1%	26	66.7%	8	42.1%
Brackish	77	19.8%	36	21.7%	5	12.8%	6	31.6%
Saline	25	6.4%	17	10.2%	8	20.5%	5	26.3%
Total	389	100.0%	166	100.0%	39	100.0%	19	100.0%

Table 4-4
Worksheet distribution by plant size vs. Phase II population

Plant Size Distribution								
	Fossil				Nuclear			
Plant Size, MW	Phase II Facilities		Spreadsheets		Phase II Facilities		Spreadsheets	
	Number	%	Number	%	Number	%	Number	%
< 200	103	26.5%	24	14.5%	0	0.0%	0	0.0%
200 - 500	96	24.7%	39	23.5%	1	2.6%	0	0.0%
500 - 1,000	99	25.4%	55	33.1%	11	28.2%	4	21.1%
> 1,000	91	23.4%	48	28.9%	27	69.2%	15	78.9%
Total	389	100.0%	166	100.0%	39	100.0%	19	100.0%

Table 4-5
Worksheet distribution by region vs. Phase II population

Regional Distribution								
	Fossil				Nuclear			
Region	Phase II Facilities		Spreadsheets		Phase II Facilities		Spreadsheets	
	Number	%	Number	%	Number	%	Number	%
Mid-Atlantic	35	9.0%	21	12.7%	10	25.6%	6	31.6%
Midwest	84	21.6%	34	20.5%	4	10.3%	1	5.3%
North Central	66	17.0%	17	10.2%	7	17.9%	3	15.8%
Northeast	65	16.7%	20	12.0%	8	20.5%	4	21.1%
Northern Plains	4	1.0%	1	0.6%	0	0.0%	0	0.0%
Pacific	21	5.4%	20	12.0%	2	5.1%	2	10.5%
South Central	44	11.3%	13	7.8%	2	5.1%	1	5.3%
Southeast	69	17.7%	40	24.1%	6	15.4%	2	10.5%
Southwest	1	0.3%	0	0.0%	0	0.0%	0	0.0%
Total	389	100.0%	166	100.0%	39	100.0%	19	100.0%

Of the 185 plants for which cost worksheets were submitted approximately two-thirds provided information of sufficient completeness and detail to allow an assessment of the factors affecting the difficulty of retrofit. The remainder provided more limited information which made the level of confidence in the determination of the difficulty of retrofit lower. In order to develop what was considered to be a representative sample of "evaluated plants", 125 plants with the most complete information were chosen for site-specific analysis. The distribution of these plants among the same categories noted above is presented in Tables 4-6 through 4-10.

Table 4-6
Distribution of analyzed plants by plant type vs. Phase II population

Distribution of Write-ups				
Plant Type	Phase II Facilities		Write-ups	
	Number	%	Number	%
Fossil	389	90.9%	115	92.0%
Nuclear	39	9.1%	10	8.0%
Total	428	100.0%	125	100.0%

Table 4-7
Distribution of analyzed plants by source water vs. Phase II population

Source Water Distribution of Write-ups								
Source Water	Fossil				Nuclear			
	Phase II Facilities		Write-ups		Phase II Facilities		Write-ups	
	Number	%	Number	%	Number	%	Number	%
Great Lakes	42	10.8%	16	13.9%	6	15.4%	3	30.0%
Lakes and Reservoirs	71	18.3%	18	15.7%	12	30.8%	2	20.0%
O/E/TR*	102	26.2%	32	27.8%	13	33.3%	4	40.0%
Rivers	174	44.7%	49	42.6%	8	20.5%	1	10.0%
Total	389	100.0%	115	100.0%	39	100.0%	10	100.0%

*Oceans, estuaries and tidal rivers

Table 4-8
Distribution of analyzed plants by source water type vs. Phase II population

Water Quality Distribution of Write-ups								
Source Water	Fossil				Nuclear			
	Phase II Facilities		Write-ups		Phase II Facilities		Write-ups	
	Number	%	Number	%	Number	%	Number	%
Fresh	287	73.8%	79	68.7%	26	66.7%	6	60.0%
Brackish	77	19.8%	24	20.9%	5	12.8%	1	10.0%
Saline	25	6.4%	12	10.4%	8	20.5%	3	30.0%
Total	389	100.0%	115	100.0%	39	100.0%	10	100.0%

Table 4-9
Distribution of analyzed plants by plant size vs. Phase II population

Plant Size Distribution of Write-ups								
Plant Size, MW	Fossil				Nuclear			
	Phase II Facilities		Write-ups		Phase II Facilities		Write-ups	
	Number	%	Number	%	Number	%	Number	%
< 200	103	26.5%	19	16.5%	0	0.0%	0	0.0%
200 - 500	96	24.7%	27	23.5%	1	2.6%	0	0.0%
500 - 1,000	99	25.4%	39	33.9%	11	28.2%	3	30.0%
> 1,000	91	23.4%	30	26.1%	27	69.2%	7	70.0%
Total	389	100.0%	115	100.0%	39	100.0%	10	100.0%

Table 4-10
Distribution of analyzed plants by region vs. Phase II population

Regional Distribution of Write-ups								
Region	Fossil				Nuclear			
	Phase II Facilities		Write-ups		Phase II Facilities		Write-ups	
	Number	%	Number	%	Number	%	Number	%
Mid-Atlantic	35	9.0%	11	9.6%	10	25.6%	2	20.0%
Midwest	84	21.6%	25	21.7%	4	10.3%	1	10.0%
North Central	66	17.0%	15	13.0%	7	17.9%	2	20.0%
Northeast	65	16.7%	18	15.7%	8	20.5%	2	20.0%
Northern Plains	4	1.0%	0	0.0%	0	0.0%	0	0.0%
Pacific	21	5.4%	16	13.9%	2	5.1%	1	10.0%
South Central	44	11.3%	12	10.4%	2	5.1%	0	0.0%
Southeast	69	17.7%	18	15.7%	6	15.4%	2	20.0%
Southwest	1	0.3%	0	0.0%	0	0.0%	0	0.0%
Total	389	100.0%	115	100.0%	39	100.0%	10	100.0%

Brief analyses of each of the selected plants are included in Appendix E. Chapter 5 gives a review of the general approach to the analyses and a summary of the important conclusions.

References-- Chapter 4

4.1 Personal communication, T. Dendy, SPX Corporation, July, 2008

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4.3 Enercon Service, Inc., "Diablo Canyon Power Plant; Cooling Tower Feasibility Study, March, 2009.

4.4 Enercon Services, Inc., "Feasibility Study for Installation of Cooling Towers and the San Onofre Nuclear Generating Station", 2009.

5
SITE-SPECIFIC ANALYSES

Approach

Analyses were performed to generate retrofit cost estimates for 125 specific plants chosen to represent the family of Phase II facilities as discussed in Chapter 4 and presented in Tables 4-1 through 4-10. The plants chosen for analysis are listed in Appendix D. The analyses were done by using the information provided by the plants in the cost information worksheets to assess the effect of the eleven site-specific features identified in Chapter 2 as influencing the degree of difficulty of a closed-cycle cooling system retrofit at the individual plant. A brief summary of the considerations is given below.

General observations

Although the degree of difficulty of a retrofit is very specifically related to the situation at each given site, some general trends are evident.

Nuclear vs. fossil

Retrofit costs at nuclear plants are generally higher for a given size plant than the corresponding costs at fossil plants. This is true for a variety of reasons. First, the cooling load in Btu/MWh is higher for nuclear plants as a result both of the lower cycle efficiency and the fact that some of the rejected heat at a fossil plant goes out through the stack and not the condenser. Therefore, the typical circulating water flow at a nuclear plant is significantly higher (675 gpm/MW for nuclear vs. ~500 gpm/MW for fossil) and hence the condenser water cooling system is correspondingly larger.

However, even on a normalized $/gpm basis the nuclear costs are higher as shown in Figure 3-5. Although the reasons for this were not explored in depth, it would seem reasonable that the regulatory oversight at nuclear plants would be more intensive; the design and construction practices more rigorous; the inspections more extensive; and the quality control requirements more stringent.

In addition, the studies from which the retrofit cost data were obtained tend to be more extensive and more recent for the set of nuclear plants used to develop the cost correlations than were those for the fossil plants. To the extent that this is an important factor in the cost differential, it may be expected that as more elaborate and up-to-date studies are performed for large fossil plants, the costs may rise to a level more comparable to the nuclear ones. However, at this time, there is no credible basis for adjusting the fossil costs other than simple scaling from the date of the studies to the present.

Neighborhood characteristics

In general, more spacious and less congested sites result in less difficult, less costly retrofits. This translates into the result that sites in remote, rural locations typically fall at the "easier" end of the difficulty scale presumably because the availability of land at the time the plant was originally sited in such locations had been much more favorable to large, open site plans than those for plants in urban locations or in areas near oceans or lakes or residential communities.

Analyses of selected plants

As discussed in Chapter 4, approximately 185 plants returned cost estimation worksheets with varying amounts of site-specific detailed descriptive information. Of those, 125 plants were selected as forming a group that was reasonably representative of the family of Phase II facilities and providing adequate information for an evaluation. An examination of each of these plants was made and a brief analysis of each is provided in Appendix E. The objective of each plant-specific analysis was to assign a degree of difficulty to a closed-cycle retrofit at that individual plant.

As discussed in Chapter 4 there were numerous factors that contributed to the difficulty of a cooling system retrofit. It was not uncommon that at any particular site some of the features made the retrofit difficult while others were consistent with an easy or average retrofit. In these situations, a rating intermediate between two degrees of difficulty would be assigned and the cost estimated to also be intermediate between the two levels of difficulty. The approach was to assign a cost mid-way between the two levels. Any attempt to develop a more fine-structured rating system to calculate am ore precise intermediate estimate not believed to be justified by the precision of the correlations.

Difficult sites

The most frequent reason for concluding that a site would be in the "Difficult" category was a combination of limited space on the site for locating a cooling tower, a large distance from the existing condensers and the likely site of the tower and, particularly, the presence of existing infrastructure in congested areas between the tower site and the turbine hall. This was often the case in older, urban plants.

Other situations included coastal plants, for a variety of reasons. First and foremost, coastal areas are often considered highly desirable locations for recreational purposes, the aesthetic beauty of coasts is often a treasured attribute and, in many cases, residential or tourist accommodations have gown up in the vicinity. In these cases, the addition of a large structure such as a cooling tower often accompanied by frequent, visible plume emissions requires plume and noise abatement which can add significantly to the difficulty and cost of a closed-cycle cooling installation.

Drift control can add significantly to the difficulty of retrofits. This is particularly the case at sites with primary water sources which are saline or brackish. If either off-site drift damage to sensitive areas or fine particle (PM-10) regulations make it infeasible to use brackish or saline make-up, the alternative may be the use of reclaimed water from municipal, agricultural or industrial facilities. The cost of obtaining such water supplies and installing pipelines to bring the water to the site can be prohibitively costly.

A second feature for saline or brackish sites involves soil conditions and site stability. Near-coastal land is often soft, saturated ground which makes the trenching and the installation of underground piping far more difficult and expensive than comparable installations at inland sites.

Easy sites

The easiest sites are typically those in remote rural areas with few neighbors and large, uncongested sites. Such sites are found more frequently in the southeast, mid-west and south central areas. In such cases, some attention must be paid to the geologic characteristics of the soil since some are underlain with rock ledge which makes the installation of underground piping difficult.

Space Constrained Sites

There are some sites where the installation of closed-cycle cooling is simply infeasible due to a lack of the space required to install closed-cycle cooling. In the majority of cases, these sites are located in dense urban locations where there is simply no space available on the site to locate a cooling tower of required size. In addition, the surrounding land is often occupied with valuable urban properties such as apartment or office buildings.

In other cases, for example at rural sites, while the existing facility site itself may have no room for a cooling tower, there may be open, undeveloped adjacent land. In some such cases it would perhaps be possible to acquire additional land, unless it is a sensitive area such as unique habitat or a state or federal park. However, in this study, the assumption has been made that if new land must be acquired in order to site a tower, this would render the site “infeasible for retrofit”.

Seven examples are provided for illustrative purposes of space constrained facilities, where a retrofit is considered infeasible. Figures 5-1 through 5-5 show plants in major urban areas. It was beyond the scope of this study to document the exact number of facilities where space constraints have the potential to make retrofitting infeasible.

Figure 5-1 is a 1,340, four unit plant with two coal-fired and two oil/gas units located in the Northeast in a combined commercial/industrial area on the bank of a major river. The site is highly congested with the only open area in a parking lot. The surrounding area is equally congested with no apparent opportunity for off-site parking if the on-site lot were to be taken to install a cooling tower.

Figure 5-1
Space constrained site; Plant No. F465

Figure 5-2 is a 113 MW plant with two oil-fired units located on an ocean harbor. It is in a crowded, downtown environment surrounded by commercial office buildings, retail stores some residential apartment/condominium complexes and a boat harbor. No space for a cooling tower is available anywhere on the site. While some open space is seen at both ends of the plant site, these are parks and urban "green space" and absolutely unavailable for plant purchase and use.

Figure 5-2
Space constrained site; Plant No. F485

Figure 5-3 is a coal fired plant with a single 348 MW unit. It is located in a mixed urban environment of industrial and commercial facilities with some residential areas nearby. The boundary shown in Figure 5-3 creates an irregular, patchwork plot plan as the result of having sold portions of the plant site in the past. The remaining site property has no adequate space for a tower contiguous to the turbine halls and only limited space at the far corners of the site.

Figure 5-3
Space constrained site; Plant No. F382

Figure 5-4 is an oil fired facility consisting of three once through cooling units totaling approximately 64 MW. The facility is located in the downtown area of a large northeastern city. The adjacent property and surrounding blocks are fully developed and/or consist of important roadways. EPA Region staff determined that a retrofit at this facility was infeasible due to space constraints

Figure 5-4
Space constrained site; Plant No. F124

Figure 5-5 is a coal fired facility consisting of five once through cooling units totaling 514 MW. This facility is located in a densely populated mid-Atlantic city. The facility property boundary is shown in the figure. The facility is surrounded by a combination of high-rise apartment buildings to the north, major roads to the west, apartments and other building to the South and a large tidal river and some federal parkland to the east and south along the shoreline

Figure 5-5
Space constrained site; Plant No. F235

Plants shown in Figures 5-6 and 5-7 are in small to mid-sized cities but located on land extending out into the neighboring water bodies. The plant in Figure 5-6 is a small, 65 MW plant with four units on once-through cooling. As indicated in Figure 5-6, the plant property is divided into three neighboring, but not adjoining, parcels separated by roadways. Only the central parcel would be a usable location for a cooling tower and it is completely full with existing structures.

Figure 5-6
Space constrained site; Plant No. F356

Similar observations apply to the site shown in Figure 5-7 sited on the shore of, and extending into, a man-made lake. There are two plants on the site consisting of five units with a total capcity of approximately 465 MW operating on once-through cooling. The site is tightly constrained on all sides by water or highways and all available space within the site boundary is in use for the existing plant operations.

Figure 5-7
Space constrained site; Plant No. F390

6
VALIDATION OF CAPITAL COST ESTIMATES

As described in Chapter 2, the methodology for estimating the capital cost of cooling system retrofit at an individual plant developed in this study consists of two basic steps. The first step establishes a likely range of capital costs simply as a function of the circulating water flow rate in the original once-through cooling system. Separate cost relationships were determined for fossil and nuclear plants. As described in Chapter 3, these cost relationships were objectively derived on the basis of independent cost information for 82 plants obtained from a variety of sources.

The second step requires placing an individual plant within the likely range of costs on the basis of the perceived degree of difficulty of a retrofit at that plant. This assignment of a degree of difficulty is based on site-specific information obtained from individual plants through the distribution of a cost estimating worksheet as described in Chapters 4 and 5. This step is more subjective and employs the application of engineering judgment. It is this step which must be tested and validated in order to establish confidence in the results of this study.

Approach to validation

There is an available set of 35 plants for which both independent capital cost information and site-specific information adequate to assign a degree of difficulty are available. For these plants, estimates made following the method described in Chapters 4 and 5 were compared with the independent cost estimates obtained from other sources.

The plants used in this process of comparison and validation are discussed in three groups. These are:

- Nine plants for which either actual retrofit costs or costs determined from highly detailed engineering studies are available.
- Fifteen ocean plants on the California coast
- Additional plants evaluated as part of this study on the basis of information provided by the plants in the cost estimating worksheets.

Detailed plant studies

Nine plants were given special attention. These are the plants for which either actual costs were available from retrofits that had been done at the site or from very thorough and well documented engineering studies by experienced engineering firms or the utility's engineering department. The comparison of this information with the estimates performed using the worksheet information were used as a means of quality control on the method and as a means of calibrating the judgment used in giving weight to the effect of the eleven different factors. The results and the guidance obtained from the analyses of these nine plants are summarized below.

Table 6-1 lists the plants and their characteristics. For these plants, in addition to the material requested in the cost estimation worksheet, more detailed cost and design information was provided. In some cases, additional information in the form of complete engineering study reports was made available. For two of the plants at which retrofits had actually been done, site visits were made.

Table 6-1
Plants with detailed cost information

Plant	Fuel	Capacity	Cooling Water Flow	Source Water	State	Cost Source
		MW	gpm			
FOS1	Coal	292	154,000	River/Fresh	WV	Actual
N321	Uranium	2,298	1,736,111	Ocean/Saline	CA	Eng'g study
F275	Coal	800	380,000	River/Fresh	GA	Eng'g study
FOS4	Coal	235	144,000	River/Fresh	KS	Actual
F483	Coal	1,170	792,000	GL/Fresh	WI	Eng'g study
N218	Uranium	2,540	2,200,000	River/Brackish	NJ	Eng'g study
N233	Uranium	1,296	452,000	Ocean/Saline	NH	Eng'g study
F546	Coal	736	588,067	GL/Fresh	IL	Actual
FOS5	Coal	550	460,000	River/Fresh	GA	Actual

The cost information is compiled in Table 6-2. The several cost categories were those common to most sites. However, the costs were reported in different formats by different plants, and the categories are not all used by every plant. Even when they are, they do not necessarily contain exactly the same cost elements in each case.

Many of the factors for those costs over and above the "Installed Equipment Subtotal" are factored as a specified percentage of some or all of the equipment costs. The chosen factors [as, for example the Contingency, Escalation, AFI ("Adjustment for Inflation"), AFUDC ("Allowance for Funds Used During Construction"), Owners Costs and others] were not the same for every plant.

Table 6-2
Detailed cost elements

Plant ID	Fos 1	N321	F275	Fos 2	F483	N218	N233	F546	Fos 5
Fuel	Coal	Nuclear	Coal	Coal	Coal	Nuclear	Nuclear	Coal	Coal
MW	292	2,298	800	235	1,170	2,540	1,296	736	550
Source water	River/Fr	Ocean/Sa	River/Fr	River/Fr	GL/Fresh	River/Br	Ocean/Sa	GL/Fresh	River/Fr
OTC Flow, gpm	154,000	1,736,111	380,000	144,000	792,000	2,200,000	452,000	508,000	460,000
Capital Costs (Date)	2006	2008	2005	2005	2007	2005	2008	2008	2001
Cooling tower(s)	$5,249,000	$242,100,000	$15,186,000	$4,319,000	$155,342,000	$61,849,000	$110,652,000	$26,031,000	$16,450,000
Cooling tower basin(s)	$1,252,000		$2,128,000	$1,638,000	$20,073,000	$22,394,000	$7,946,000	$9,263,000	$2,359,000
Piping and valves	$1,983,000	$178,800,000	$19,027,000	$2,418,000	$32,514,000	$127,574,000	$20,308,000	$13,694,000	$18,560,000
Pumps	$626,000	$72,000,000	$2,577,000	$884,000	$10,876,000	$74,310,000	$28,574,000	$8,703,000	$7,831,000
Condenser modifications	$0	$83,800,000	$0	$49,000	$0	$135,216,000	$0		$0
Electrical	$4,279,000	$100,900,000	$11,322,000	$2,355,000	$12,323,000	$32,561,000	$8,450,000	$16,344,000	$10,458,000
Miscellaneous						$0	$0		
Site development	$459,000	$586,600,000	$10,456,000	$9,649,000	$55,436,000	$0	$3,477,000	$14,759,000	$7,263,000
MU and BD systems	$4,352,000	$143,100,000			$394,000	$12,967,000		$574,000	
Chemical treatment			$428,000	$399,000	$506,000	$11,451,000		$634,000	$102,000
I&C	$365,000	$23,700,000		$218,000	$842,000			$3,275,000	
Fire and lightning protection			$1,110,000	$742,000				$40,000	
Security		$44,200,000			$4,248,000	$619,000			
Other	$960,000	$154,400,000	$689,000	$154,000			$535,000		$511,000
Installed equip't (Total)	**$19,525,000**	**$1,629,600,000**	**$62,923,000**	**$22,825,000**	**$292,554,000**	**$478,941,000**	**$179,942,000**	**$93,319,000**	**$63,534,000**
Escalation								$0	
Labor	$0	$0	$0	$0	$5,195,000	$0	$0	$0	$0
Materials					$732,000			$0	
Engineered equip't					$2,529,000			$0	
Subcontracts					$2,030,000			$0	
Escalation (Total)	**$0**	**$0**	**$15,598,000**	**$0**	**$10,486,000**	**$120,839,000**	**$0**	**$28,041,000**	**$0**
								$0	
AFI					$30,304,000			$0	
Indirects		$166,000,000		$191,000	$1,667,000			$0	
Construction management	$2,296,000	$131,700,000	$6,830,000	$456,000	$7,538,000	$23,947,000	$4,590,000	$3,275,000	$4,924,000
Engineering		$74,700,000	$1,998,000	$1,262,000	$33,903,000	$47,894,000	$3,732,000	$17,467,000	$5,533,000
Startup & Commission		$50,000,000	$543,000		$0		$3,672,000	$1,091,000	$383,000
Transportation		$189,000,000			$7,809,000			$0	
Equipment spares					$20,000		$5,416,000	$0	
Other				$275,000	$976,000			$32,432,000	$3,045,000
PROJECT SUBTOTAL	$21,821,000	$2,241,000,000	$87,892,000	$25,009,000	$385,257,000	$671,621,000	$197,352,000	$175,625,000	$77,419,000
Contingency		$448,200,000	$17,579,000		$38,526,000	$141,336,000	$9,868,000	$24,696,000	$7,438,000
Owner's costs	$783,000		$579,000	$543,000	$0	$72,252,000			$2,628,000
AFUDC	$1,921,000		$16,350,000		$0				$6,236,000
TOTAL	**$24,525,000**	**$2,689,200,000**	**$122,400,000**	**$25,552,000**	**$423,783,000**	**$885,209,000**	**$207,220,000**	**$200,321,000**	**$93,721,000**

Comparisons with estimates (for plants listed in Table 6-1)

In order to compare the detailed cost data for these plants with the costs estimated using the degree of difficulty methodology for these plants, it is necessary to understand which cost elements were included in the cost data that were used to develop the correlations. In this regard, two considerations are important.

The first is whether or not the cost data used to develop the cost relationships in Chapter 3 included items in addition to the simple cost of the installed equipment. At the time some of the data were assembled in 2002 (6-1), plant personnel for many of the plants were contacted in an attempt to determine whether the costs included items such as Engineering, Contingency, Escalation, AFI and AFUDC. In some cases, this could not be determined. In most cases, the figures included Engineering and Contingency but not an explicit allowance for Escalation, AFI or AFUDC.

Therefore, in making the comparisons with the detailed cost information provided by the nine plants listed in Table 6-1, the reported costs were adjusted by subtracting the AFI, AFUDC and Escalation quantities from those plant totals where they were specifically identified and accounting for the effect that these deductions had on the reported Contingency. The Contingency was included while recognizing that it may well have been computed on a basis very different from what was typical of the data upon which the cost relationships were based.

The second consideration was whether the cooling tower costs were for conventional towers or for plume-abated towers. As stated in Chapter 4 (See Item 6 under Important Plant/Site Characteristics), the cost of plume abatement towers can be up to three times the cost of conventional, mechanical-draft cooling towers of the same cooling capability. It was determined, however, that only two of the 82 plants at which the cost data upon which the cost relationships were based included plume-abatement towers. Therefore, the cost relationships, as formulated in Chapter 3, cannot adequately account for the cost of plume-abatement at sites where it may be required.

Therefore, in validating the cost relationships, when comparisons were made against detailed cost estimates from plants which chose to use plume-abated towers, the tower costs were reduced by a factor of 2.5. This is not to suggest that these plants did not require plume-abated towers or that the requirement does not represent an important cost of retrofit. The adjustment is merely a device to permit consistent comparisons between the basic cost relationships as they were developed and individual plant costs. It should be noted that the cost of the towers themselves generally represent between 15 and 30% of the total retrofit project cost. Therefore a reduction by a factor of 2.5 in the tower cost results in a total retrofit cost reduction of from 6 to 12%. A satisfactory agreement between the estimated cost and the adjusted reported cost suggests that the cost relationship represents the bulk of the retrofit cost satisfactorily.

However, the question remains of whether the cost relationships as developed might systematically underestimate the national cost by not accounting for the cost of plume abatement even though it would be generally expected to be necessary at some fraction of the plant eligible for retrofit. This was accounted for as follows. First, in performing the site-specific analyses, for those sites at which plume abatement was deemed to be necessary, the ranking was adjusted in the direction of a higher degree of difficulty and the estimated cost was adjusted by 10%. The effect of this was to increase the fraction of cases judged to be in the higher degree of difficulty categories. As will be explained in more detail in Chapter 8, this caused the allocation of the national family of eligible existing facilities to be shifted slightly to higher degrees of difficulty resulting in a higher total national capital cost of retrofit.

No information is available to this study on the fraction of cooling towers sold which are plume-abated. However, if it were assumed that one quarter of the towers were plume-abated towers, an increase of 10% of the retrofit cost for one quarter of the cases would result in only a 2.5% increase in the total national cost of retrofit which is well within the level of accuracy of these estimates.

A comparison of the project estimates using the cost relationships developed in Chapter 3 and the degree of difficulty estimates with the adjusted costs provided by the plants is shown in Table 6-3. Plant N321 represents a retrofit of extremely high cost as was discussed in Section 5. It is excluded from the comparisons on the basis discussed in Section 3. (See Figure 3.1). Of the eight remaining comparisons, the estimates were low in three cases and high in five cases. Six of the estimates were within +/- 10%, seven within +/- 25%. One of the estimates differed from the reported costs by more than 50% on the high side.

The aggregated estimates for all eight plants agreed to within about 4%.

Tables 6-4 and 6-5 display the costs in two different ways. Table 6-4 lists the individual cost elements expressed as normalized cost per unit flow ($/gpm) which is the correlating basis used in the study to estimate total project costs. Table 6-5 displays the cost of each element as a percentage of the total project cost. The right hand column in each table is the average of the respective values in each table for eight of the nine plants excluding N321. N321 was excluded to avoid distorting the averages with a retrofit of extreme difficulty and extraordinarily high costs. However, the values for the plant are displayed in the table as an example of what retrofit costs can be at unusually difficult sites.

For most sites, of the 14 cost elements, four groups account for nearly all the cost. These are the cooling tower and basin, the recirculating water systems (pumps plus piping and valves), the site development costs and the electrical costs. Using the average values these four cost groups account for over 90% of the total costs. These four cost elements will be discussed separately.

Table 6-3
Comparison of plant-provided costs with project estimates

Plant ID	Fos 1	N321	F275	Fos 2	F483	N218	N233	F546	Fos 5	"Eight Plant Total"
Total reported cost	$24,525,000	$2,689,200,000	$122,400,000	$25,552,000	$423,783,000	$885,209,000	$207,220,000	$200,321,000	$93,721,000	
Adjusted cost	$22,604,000	$2,689,200,000	$87,332,738	$25,552,000	$252,565,006	$741,412,613	$133,704,327	$172,279,000	$87,487,196	$1,522,936,880
Project estimate										
Fossil										
Easy	$27,874,000		$68,780,000	$26,064,000	$143,352,000			$91,948,000	$83,260,000	
Average	$42,350,000		$104,500,000	$39,600,000	$217,800,000			$139,700,000	$126,500,000	
Difficult	$62,370,000		$153,900,000	$58,320,000	$320,760,000			$205,740,000	$186,300,000	
More difficult	$87,780,000		$216,600,000	$82,080,000	$451,440,000			$289,560,000	$262,200,000	
Nuclear										
Less difficult		$475,694,414				$602,800,000	$123,848,000			
More difficult		$1,118,055,484				$708,400,000	$291,088,000			
Estimated degree of difficulty	Easy	"Extreme"	Easy to average	Easy	Average to difficult	Intermediate	Less difficult	Difficult	Easy	
Project estimate	$27,874,000	>$1,118,055,484	$86,640,000	$26,064,000	$269,280,000	$790,600,000	$123,848,000	$205,740,000	$83,260,000	$1,585,432,000
% difference	23.3%	na	-0.8%	2.0%	6.6%	6.6%	-7.4%	19.4%	-4.8%	4.1%

"Eight Plant Total" excludes N321

Table 6-4
Cost elements expressed as normalized costs ($/gpm)

Item	Fos 1	N321	F275	Fos 2	F483	N218	N233	F546	Fos 5	8 Plant Average
Cooling tower(s)	$34.08	$139.45	$39.96	$29.99	$196.14	$28.11	$244.81	$39.42	$35.76	$81.04
Cooling tower basin(s)	$8.13	$0.00	$5.60	$11.38	$25.34	$10.18	$17.58	$14.03	$5.13	$12.17
Piping and valves	$12.88	$102.99	$50.07	$16.79	$41.05	$57.99	$44.93	$20.74	$40.35	$35.60
Pumps	$4.06	$41.47	$6.78	$6.14	$13.73	$33.78	$63.22	$13.18	$17.02	$19.74
Condenser modifications	$0.00	$48.27	$0.00	$0.34	$0.00	$61.46	$0.00	$0.00	$0.00	$7.73
Electrical	$27.79	$58.12	$29.79	$16.35	$15.56	$14.80	$18.69	$24.75	$22.73	$21.31
Miscellaneous	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Site development	$2.98	$337.88	$27.52	$67.01	$69.99	$0.00	$7.69	$22.35	$15.79	$26.67
MU and BD systems	$28.26	$82.43	$0.00	$0.00	$0.50	$5.89	$0.00	$0.87	$0.00	$4.44
Chemical treatment system	$0.00	$0.00	$1.13	$2.77	$0.64	$5.21	$0.00	$0.96	$0.22	$1.37
I&C	$2.37	$13.65	$0.00	$1.51	$1.06	$0.00	$0.00	$4.96	$0.00	$1.24
Fire and lightning protection	$0.00	$0.00	$2.92	$5.15	$0.00	$0.00	$0.00	$0.06	$0.00	$1.02
Security	$0.00	$25.46	$0.00	$0.00	$5.36	$0.28	$0.00	$0.00	$0.00	$0.71
Other	$6.23	$88.93	$0.00	$1.07	$0.00	$0.00	$1.18	$0.00	$1.11	$1.20
Total	$126.79	$938.65	$163.77	$158.51	$369.39	$217.70	$398.10	$141.33	$138.12	$214.21

Table 6-5
Cost elements as percentage of total equipment cost

Item	Fos 1	N321	F275	Fos 2	F483	N218	N233	F546	Fos 5	8 Plant Average
Cooling tower(s)	26.9%	14.9%	24.4%	18.9%	53.1%	12.9%	61.5%	27.9%	25.9%	31.4%
Cooling tower basin(s)	6.4%	0.0%	3.4%	7.2%	6.9%	4.7%	4.4%	9.9%	3.7%	5.8%
Piping and valves	10.2%	11.0%	30.6%	10.6%	11.1%	26.6%	11.3%	14.7%	29.2%	18.0%
Pumps	3.2%	4.4%	4.1%	3.9%	3.7%	15.5%	15.9%	9.3%	12.3%	8.5%
Condenser modifications	0.0%	5.1%	0.0%	0.2%	0.0%	28.2%	0.0%	0.0%	0.0%	3.6%
Electrical	21.9%	6.2%	18.2%	10.3%	4.2%	6.8%	4.7%	17.5%	16.5%	12.5%
Miscellaneous	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Site development	2.4%	36.0%	16.8%	42.3%	18.9%	0.0%	1.9%	15.8%	11.4%	13.7%
MU and BD systems	22.3%	8.8%	0.0%	0.0%	0.1%	2.7%	0.0%	0.6%	0.0%	3.2%
Chemical treatment system	0.0%	0.0%	0.7%	1.7%	0.2%	2.4%	0.0%	0.7%	0.2%	0.7%
I&C	1.9%	1.5%	0.0%	1.0%	0.3%	0.0%	0.0%	3.5%	0.0%	0.8%
Fire and lightning protection	0.0%	0.0%	1.8%	3.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%
Security	0.0%	2.7%	0.0%	0.0%	1.5%	0.1%	0.0%	0.0%	0.0%	0.2%
Other	4.9%	9.5%	0.0%	0.7%	0.0%	0.0%	0.3%	0.0%	0.8%	0.8%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Cooling tower and basin

Of the 9 plants, the cooling tower costs for 6 of them range from $28 to $40 per gpm, which is a reasonable range for counterflow, mechanical draft towers without plume abatement. For Plants N321, F483 and N233, the reported costs were $140/gpm, $196/gpm and $245/gpm respectively. In the latter two cases, the reported costs were for plume abatement towers which commonly cost 2.5 to 3 times non-abated towers. However, even if both costs are reduced by a factor of 3, those costs are still $65/gpm and $82/gpm respectively, well above the normal range.

Plant N321 reported a base cost for only the towers themselves of $46/gpm is reasonably consistent with the other sites, especially given that the tower will operate on seawater make-up. However, the underlying report goes on to include additional costs for “mechanical”, “electrical” and “fans” which essentially triple the reported cost of the tower to $139/gpm. These costs significantly exceed any corresponding costs in other reports, and there is no available information to evaluate them.

The underlying report on the retrofit costs for Plant F483 indicates that the location of the towers required the demolition and removal of retired units. It may be that some of these costs were allocated to the towers themselves rather than to a “Site Development” category.

Plant N233 reports the highest tower costs even after an adjustment to account for plume abatement. Two factors may contribute to the cost. First, the tower will operate on seawater make-up. Second, the plant is located near the coast in what appears to be flat, marshy ground with a presumably high water table. Therefore, a possible reason for the elevated cost may be the costs of foundation preparation or pilings needed to support the tower and basin. Given the very low amount allocated to Site Preparation, the costs may be included in the tower costs.

The basin costs for 6 of the 9 units range from $5/gpm to $14/gpm. For a simple assumption of 500gpm/MW and 15,000 gpm per tower cell and cell dimensions of 50’ x 50’, a normalized basin cost of $10/gpm translates to $\$60/ft^2$. A range of $5 to $14/gpm translates to $\$30/ft^2$ to $\$84/ft^2$ which is reasonably consistent with commonly reported costs of $40 to $\$50/ft^2$. Two plants (F483 and N233) report substantially higher costs of $18/gpm and $25/gpm respectively [$\$108/ ft^2$ and $\$150/ ft^2$] and are two of the three plants reporting the high tower costs. As before, it may be that site preparation costs were included in the basin costs and, in the case of N233, that site soil conditions required special foundation work. In any case, using the numbers as reported for 6 of the 9 plants, the tower/basin costs accounted for 17.6% to 37.8% of the total retrofit costs with an average of 24.3%.

Circulating water system (pumps, piping and valves)

The costs of the circulating water systems are highly variable on both a normalized ($/gpm) basis and as a percentage of the total equipment costs. While the fundamental size of the piping, valves and pumps is related directly to the water flow rate, the location of the tower relative to the existing condenser, the elevation change from the condenser discharge to the tower distribution deck and the site soil conditions into which the piping must be installed are entirely site-specific. The normalized costs for 8 of the 9 plants vary from $17 to $108/gpm; the costs as a percentage of the total vary from 13% to 42%. These costs, along with the Site Preparation costs which are discussed below, are a major source of the site-specific variability in retrofit costs.

Site preparation

Site preparation costs are the most highly variable of the major cost elements ranging from 0% in one case to over 42% in another with an average of 15%. While the “0%” figure undoubtedly means that the site preparation costs were included implicitly in other elements, two plants report 1.9% and 2.4%. It is this factor, along with the circulating water system costs, that accounts for the highly site-specific nature of the retrofit costs and for the high degree of variation in the cost from the “Easy” to “Difficult” or “More Difficult” projects.

Electrical

The costs categorized as “Electrical” are primarily associated with the cost of providing additional station power and motor control centers for the cooling tower fans and the increased pump power requirements. As will be discussed in more detail in Section 7, this additional power is almost directly proportional to the circulating water flow. Therefore, on a normalized ($/gpm) basis the cost should be relatively constant from site to site. For 8 of the 9 sites (excluding again N321) the normalized electrical cost ranges from $15 to $30/gpm with an average of $23/gpm, all within a range of +/-25 to 30%.

Individual plant estimates

For Plant FOS1, even the “Easy” designation resulted in an overestimate of the costs by nearly 20%. It is, of course, to be expected that a linear, “best fit” approximation to a set of data points will have to overestimate some of the points used to develop the approximation. This is observed in Figure 3-11 where some portion of points lie below the correlating line in every case. However, there was no basis in any of the site-specific estimates to conclude that a particular case was “exceptionally easy”. Therefore, the lowest estimate ever assigned was that consistent with an “Easy” designation.

Plant N321 represents an extreme case. As noted in Section 3 as part of the discussion on development of the cost relationships, the reported costs were much higher on both an absolute and normalized basis than for any other site. This is due in large measure to the highly irregular terrain on which the plant is built and its isolated location which makes it difficult and costly to bring equipment, materials and the labor force to and from the plant. The total costs were excluded from the cost function development on the grounds that including them would inflate or otherwise bias the cost relationship for other, less extreme sites. Herein, the costs and cost elements are included in the tables and the discussion for illustrative purposes and to provide an example of how costly cooling system retrofits can be in some situations, but excluded from the averages on the same basis for which they were excluded from the correlation analysis.

For Plants F275 and FOS 5, the estimates were satisfactory and both within 5%. In both cases, the costs for "Piping and Valves" were a higher fraction of the total equipment costs than appears typical. In the case of Plant FOS 5, where the retrofit was actually performed, the decision was made to use a single set of pumps to pump the water through the condenser and to the top of the tower in a single lift. This required reinforcement of the condenser and some of the existing circulating water tunnels and replacement of the existing circulating water pumps. This would be expected to result in a somewhat higher cost than the alternate approach described in Chapter 2. It is assumed that the estimates for FOS 2 used the same approach.

For Plants F483 and N233, the reported costs included the installation of plume-abated towers. The data upon which the cost relationships were based does not include any cases using plume abatement towers. Since plume-abated towers are expected to cost between 2 and 3 times the cost of standard towers, the estimates were adjusted by reducing the cooling tower costs by a factor of 2.5. The effect on the total project costs is seen to be significant. In both cases, the adjusted costs and the estimated costs based on the determined degree of difficulty was within 10%. Another approach would have been to adjust the degree of difficulty to Difficult or More Difficult to account for the need for plume abatement. This was not done because the site analysis for this study did not conclude that plume abatement would be necessary even though the reported studies done for the plants chose to include it. Therefore, although plume abatement may well be required at these sites for reasons that were not recognized in the site-specific analysis, in order to maintain consistency in the rating methodology, the lower degree of difficulty was assigned and the reported costs adjusted in a plausible way for purposes of the comparison.

For Plant FOS 2, the retrofit was determined to be "Easy". The agreement was satisfactory, within 2%, even though the site development costs were a high percentage of the total, a situation normally associated with more difficult retrofits. Therefore, the close agreement was likely somewhat fortuitous.

Plant N218 requires special discussion. The reported retrofit costs are significantly different from the other 8 plants in that the cooling system has been re-optimized, as discussed in Section 4, Item 11. In this case the circulating water flow in the new closed-cycle systems is one-half that of the circulating water flow in the original once-through cooling system. As would be expected, the cooling tower is smaller and cheaper than it would have been if the system has not been re-optimized and the cooling water flow kept at its original level. The normalized costs in Table 6-4 use the original flow rate. Had the new, lower flow been used the normalized costs in $/gpm would be double those listed but the individual element costs, listed in Table 6-5 as a percentage of the total cost would remain the same.

This has the effect of raising the normalized tower costs to $56/gpm and the basin cost to $20/gpm or $120/ft^2. These costs are at the high end of the range but are not unreasonable for a tower on brackish make-up and at a near-coastal site with a high water table. Two items are noteworthy. First, the lower cooling tower cost is more than made up for by the high cost of condenser modification ($135,000,000 vs. $62,000,000). As noted in Table 6.4, the total reported capital cost of $885,000,000 exceeds the "More Difficult" estimate by approximately 25% if the closed-cycle cooling water flow rate is used in the estimating cost function. A plausible approach to estimating the cost is to use the correlation equation with the lower flow rate for the determined degree of difficulty for all the costs other than the condenser modification and then adding the condenser modification cost to the result. If this approach is adopted the total estimated retrofit cost is $790,600,000 ($655,600,000 + $135,000,000) which is within 7% of the reported cost of $741,413,000.

Information provided for Plant F546 described a site with limited space and a congested area between the likely location of the tower and the existing condensers which would lead to high costs for the installation of the circulating water lines. The site had, therefore, been rated as "Difficult" in the site-specific analysis. Detailed cost information provided by the plant gave costs for 8 different possible retrofit configurations with a range of total installed costs ranging from under $200 million to nearly $300 million. The options were quite different in the types of tower used, the location on the site and the approach to routing the circulating water around the site. No final recommendation was made as to which was the preferred site. Following discussion with plant staff, it was decided to use the average of the eight costs as the "probable" retrofit cost. The rating of "Difficult" gave an estimated cost about 20% higher than the average of the detailed cost estimate for the 8 options but well below the highest cost options. There is no basis available to this study to choose which of the options is the most likely to be chosen so the comparison with the average was used.

California ocean plants

A previous study of estimated retrofit costs for coastal plants in California was conducted in 2007 (6-2). Essentially the same methodology was used in that study as in the current study. Concurrently, another study of the California ocean plants was sponsored by the California Ocean Protection Council and conducted by TetraTech Corporation (6-3). The methodology in that study was a more "bottom-up" approach to cost estimating in which each site was either visited or plant drawings were examined in detail, a specific approach to retrofit was assumed, and a cost estimate was constructed based on detailed bid sheets by a qualified engineering firm. Detailed descriptions of the methods and results of both studies are available in the above references.

Direct comparisons of the estimated costs from the two studies were possible at 15 of the California coastal plants. The total costs of retrofit for all 15 plants agreed within 5% suggesting that there was no systematic bias in the more generalized estimating methodology of this study. Figure 6-1 shows a comparison of the results for the 15 plants.

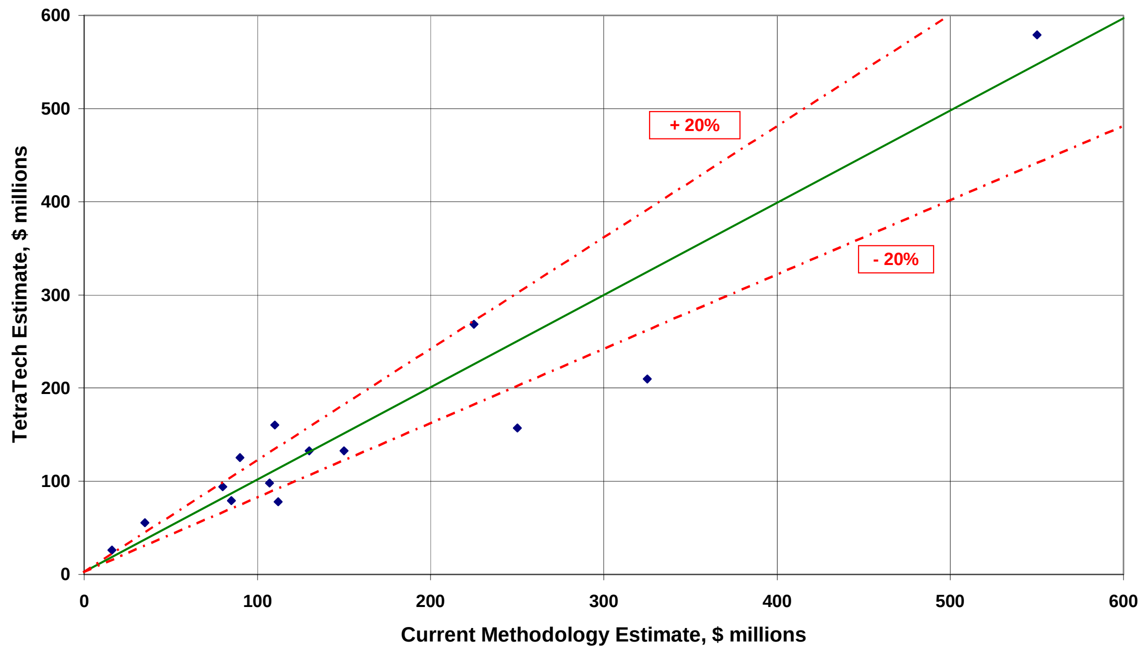

Figure 6-1
Comparison of retrofit cost estimates for California coastal plants

Most of the comparisons are within +/-25%. In two cases the estimates differed more significantly with the current methodology giving estimates that exceeded the TetraTech estimates by over 50%. In both cases, the difference was largely attributable to the fact that the current estimate was weighted to the "Difficult" level because of the judgment that plume abatement would be required at the sites while the TetraTech estimate assumed standard, non-abated cooling towers. Additional differences in assumptions regarding the location and number of cooling towers required accounted for much the remaining difference in the estimated costs. On balance, the agreement is judged to be satisfactory.

Additional selected plants

In addition to the eight detailed plants and the 15 California ocean plants discussed above, there are an additional 34 plants for which adequate site-specific information and independent cost estimates were available. Assessments of the degree of difficulty and estimates of the capital cost of retrofit were developed for each these plants using the approach described in Chapters 4 and 5.

Table 6-6 lists all 34 plants. These plants are a subset of the 82 plants used to establish the cost ranges as described in Chapter 3. Direct comparisons were made between the independent cost estimates and the current study estimates resulting from the application of the methodology developed herein. The cost estimates presented are the capital costs only and do not include additional costs of operating power, cooling system maintenance, plant efficiency loss, plant outage time and permitting.

Table 6-6
Comparisons with independent estimates

Nuclear				
Plant ID	Circulating Water Flow	Degree of Difficulty	Estimated Cost	Reported Cost
	gpm		$	$
N178	1,886,000	Less D	$516,764,000	$558,151,000
N218	2,200,000	Int	$1,009,800,000	$885,210,000
N302	1,621,528	Int	$744,281,250	$614,558,000
N233	452,000	Int	$207,468,000	$225,000,000
N459	974,600	More D	$627,642,400	$590,672,000
Total nuclear			$3,105,955,650	$2,873,591,000
Fossil				
Fos 6	270,000	E to Av	$60,345,000	$51,900,000
Fos 5	460,000	E to Av	$102,810,000	$121,000,000
Fos 2	144,000	Av	$39,600,000	$31,000,000
Fos 1	154,000	Easy to Average	$34,419,000	$25,000,000
F540	560,500	E	$101,450,500	$152,117,000
F535	545,486	Av to D	$228,558,634	$155,118,000
F509	475,694	Av	$130,815,972	$142,000,000
F486	508,000	D	$205,740,000	$159,000,000
F483	792,000	MD	$451,440,000	$423,782,000
F449	870,000	Av to D	$364,530,000	$368,768,000
F445	810,000	Av to D	$339,390,000	$287,900,000
F439	800,200	Difficult	$324,081,000	$225,013,000
F433	786,200	Av	$216,205,000	$105,200,000
F424	740,000	Av	$203,500,000	$142,294,000
F420	704,167	D	$285,187,500	$162,800,000
F408	642,000	Av	$176,550,000	$134,429,000
F387	177,600	E to Av	$39,693,600	$25,164,000
F382	224,306	MD	$127,854,167	$128,533,000
F348	365,277	D	$147,937,185	$169,376,000
F341	167,400	E to Av	$37,413,900	$59,500,000
F318	148,000	Av to D	$62,012,000	$145,792,000
F283	400,000	Av to D	$167,600,000	$251,920,000
F281	392,000	Av to D	$164,248,000	$171,520,000
F277	382,000	Average to Difficult	$160,058,000	$155,118,000
F275	380,500	E to Av	$85,041,750	$102,000,000
F256	356,944	D	$144,562,500	$142,100,000
F252	343,750	Av to D	$144,031,250	$160,500,000
F155	56,400	Av	$15,510,000	$27,900,000
F146	70,000	E	$12,670,000	$14,268,000
Total fossil			$4,573,254,958	$4,241,012,000
Total all plants			$7,679,210,608	$7,114,603,000

Figure 6.2 plots the independent cost estimate against the estimate developed using the methodology of this study. Two items are noteworthy. First, the totals of the capital costs for all 34 plants show essentially perfect agreement----$7,115,000,000 from the independent sources vs. $7,679,000,000 using the estimating methodology---or an agreement to within less than 8%. Similar agreement is found for the total retrofit costs in the two sub-groups discussed above providing support for the conclusion that there is no systematic bias in the estimating methodology and that reliable results are obtainable on an aggregate basis.

The quality of the agreement for individual plants is varied as would be expected considering the important influence of site-specific conditions at every site. Of the plants for which comparisons were made, the methodology developed in this study differed from the independent assessments from various sources on the high side in 19 cases and on the low side in 18. In 15 cases the differences were more than +/- 20% with five on the high side (> +20%) and ten on the low side (< -20%). Of the five nuclear plants, only one differed by more than 20%. The sites with the highest differences were primarily those with crowded plant conditions located in urban areas on the coast. In these cases, the magnitude of the difficulties posed by site geology, space availability and the presence of underground interferences is very difficult to judge based on interpretations of aerial photos and simple plot plans. Any differences in judgment can lead to large differences in the assumed degree of difficulty and estimated cost.

The differences between estimates produced using the methodology of this study and the results of independent estimates at plants for which they were available were both on the high side and the low side. Therefore, it is concluded that, while the differences at individual sites can be significant, there is no evidence of any systematic bias in the methodology, suggesting that confidence can be placed in aggregated totals.

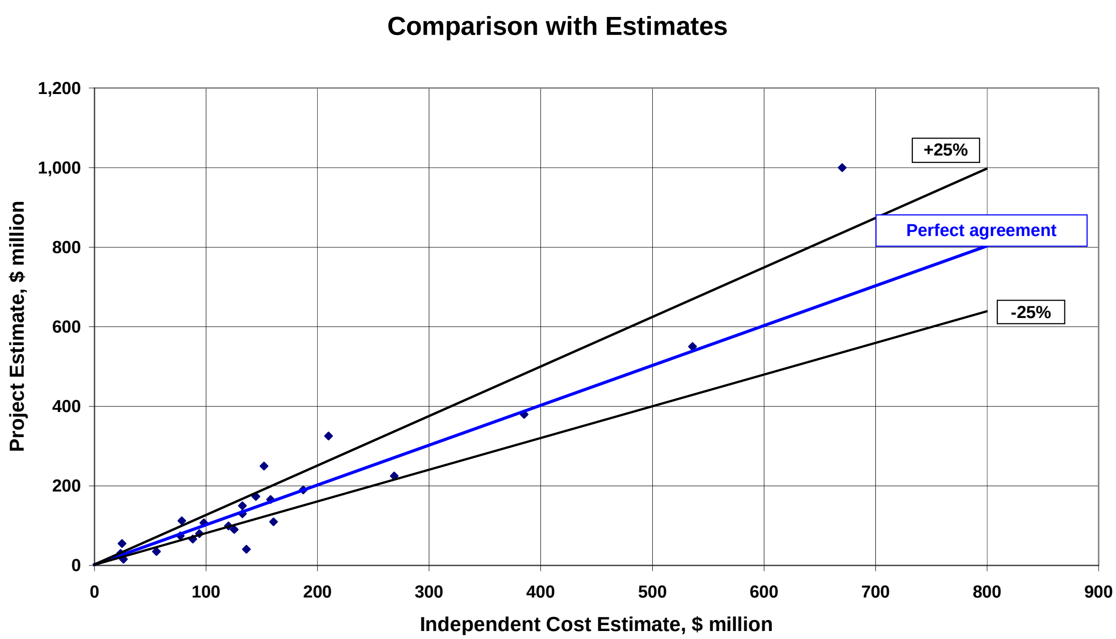

Figure 6-2
Plot of comparable cost estimates

References-- Chapter 6

6-1: *Cooling System Retrofit Cost Analysis,* EPRI, Palo Alto, CA, Technical Update 1007456, 2002

6-2: *Issues Analysis of Retrofitting Once-Through Cooled Plants with Closed-Cycle Cooling: California Coastal Plants*, EPRI, Palo Alto, CA 2007. TR-052907

6-3: *California's Coastal Power Plants: Alternative Cooling System Analysis*, Tetra Tech, Inc., Golden CO; T. Havey, Project Manager, Prepared for California Ocean Protection Council, February, 2008. (Available at http://www.waterboards.ca.gov/water_issues/programs/npdes/cwa316.shtml):

7
OTHER RETROFIT COSTS

Introduction

The simplest approach to retrofitting once-through cooled plants with a closed-cycle cooling system, as described in Chapter 2, retains the existing condenser and circulating water pumps and operates at the same circulating water flow rate as the original once-through system. This study assumes that the cooling cycle is closed by installing a mechanical-draft, counterflow cooling tower, new circulating water lines between the condenser and the tower, new circulating water pumps and a sump for the condenser discharge flow, if needed. Modifications are made to the existing inlet/discharge piping, tunnels and structures as required to accommodate make-up and blowdown from the cooling tower and to integrate the newly installed tower loop with the existing condenser loop. This is illustrated in Figures 2-1 through 2-3.

This is the approach that was adopted in nearly all of the 82 retrofit projects for which the cost estimates that formed the basis of the cost functions. Therefore, the retrofit project costs developed herein are implicitly based on the assumption that this approach will be taken in all cases.

This approach typically incurs the lowest initial capital cost, requires the minimum amount of downtime and is the least disruptive to plant operation both during and after the retrofit. However, in addition to the initial capital cost, other costs are incurred. These include the cost of increased operating power and maintenance, the costs of reduced plant efficiency imposed by the higher condenser operating temperatures normally imposed by the retrofit and the cost of plant downtime during the installation of the retrofitted system. While a rigorous analysis of these costs is beyond the scope of this study, some general estimates are subsequently provided.

In addition, there are alternative retrofit approaches which may be preferred in some specific situations. Among these are designing for a different circulating water flow and modifying the condenser accordingly, the selection of a natural-draft cooling tower as opposed to a mechanical-draft tower or the adoption of a hybrid or dry cooling system in place of an all-wet, closed-cycle cooling system. While none of these will be examined in detail, a brief discussion of each follows.

Finally, there are a number of items such as regulatory, permitting and environmental issues which affect the total cost of retrofit in ways which are difficult to quantify generically but nonetheless can be significant. They are also briefly reviewed.

Cost of increased operating power requirements

The additional operating power required by a closed-cycle cooling system using a wet, mechanical-draft cooling tower consists of two parts: pumping power and fan power.

Increased pumping power

As described in Chapter 2 and illustrated in Figure 2-3, the pumping power for the retrofitted system consists of both the power used by the original once-through cooled system, which remains essentially unchanged in most cases, and the added power required to pump the circulating water from the condenser exit to the top of the cooling tower. From there it is assumed that the water returns to the intake of the original circulating water pumps by gravity. A small amount of additional power is required to provide make-up to the closed-cycle system and to discharge blowdown form the system. However, these flows are a small fraction (typically less than 5%) of the recirculating flow, and this additional power is neglected in these estimates.

Consistent with that approach, the additional pumping power required is a function simply of the circulating water flow rate and the head required to convey the water from the condenser discharge sump to the distribution deck of the cooling tower, which is made up of the elevation change from the condenser discharge sump to the distribution deck plus the frictional pressure drop in the circulating water line to the tower. Both of these vary depending on the circulating water flow rate of the existing once-through system and the layout of the newly installed closed-cycle system. Some general rules-of-thumb are used to estimate the magnitude of this additional pumping power requirement.

Table 7-1 gives a reasonable range of flow rates, tower heights and separation distance of the tower from the condenser encountered at a range of plant and site conditions.

Table 7-1
Range of pumping power estimating parameters

Typical range	Circulating water flow (gpm/MW)	Elevation Change (ft)	Distance to Tower (ft)
Minimum	400	30	500
Intermediate	600	45	1000
Maximum	800	60	2000

The range of circulating water flow rates is based on the information presented in Figure 3-2. A typical height of the distribution deck above grade at the tower location ranges from 25 feet for an in-line configuration to 35 to 40 feet for a back-to-back arrangement. In the case of plume abatement towers, the lift is greater still, but some designs utilize a siphon effect to reduce the pumping requirement. In addition, the tower must be placed somewhat above the condenser location to allow for gravity drain of the cold water back to the condenser, and the condenser discharge bay or sump from which the new circulating pumps draws is typically below the condenser intake level. The range of separation distances from the condenser to the tower is consistent with site-specific examinations as described in Chapter 5. The frictional pressure drop over this distance is based on the assumption of a pipe size designed for a typical flow velocity of 9 feet/second. Finally a combined pump/motor efficiency of 76.5% (a motor efficiency of ~ 90% and a pump efficiency of ~ 85%) is assumed.

The cumulative result of these assumptions is a range of additional pumping power from a minimum of about 0.3% to a maximum of approximately 1.1% of plant output or 3 to 11 MW for a 1,000 MW plant.

Fan power

Similar assumptions can be used to estimate the amount of fan power required. The tower design choice of the number of cells in the cooling tower per unit of circulating water flow varies with a number of factors including make-up water quality, site climatological characteristics and the space available to place the tower. Typical ranges of circulating water flow, water loading per cell and fan horsepower are tabulated in Table 7-2.

Table 7-2
Range of fan power estimating parameters

Typical range	Circulating water flow (gpm/MW)	Cell loading (gpm/cell)	Plant Output per Cell (MW/cell)	Fan Power per Cell (HP/cell)
Minimum	400	20,000	50.0	125
Intermediate	600	15,000	25.0	175
Maximum	800	10,000	12.5	225

These ranges result in fan power requirements from a minimum of 0.21% to 1.5% of plant power which amounts to 2.1 MW to 15 MW for a 1,000 MW plant. However, the combination of a low power fan with high cell water loadings and vice versa is unlikely so the mid-range estimate (intermediate fan power with intermediate water loading) of 0.6% or 6 MW for a 1,000 MW plant is reasonable.

The sum of the additional operating power required is, therefore, estimated to range from about 0.9 to 1.7% of plant output which amounts to 9 MW to 17 MW for a 1,000 MW plant.

Heat rate penalty

Conversion of a once-through cooling system to a closed-cycle cooling system using a wet cooling tower frequently results in an increase in the achievable turbine backpressure for most of the year and a corresponding loss of plant efficiency and output. In most circumstances, this loss is greatest during the hottest period of the year at precisely the time that the power requirement of the electrical network is at its peak.

A proper determination of the heat rate penalty requires a calculation of the plant output throughout the year on both the original once-through cooling system and the retrofitted closed-cycle system. This begins with a calculation of the condensing pressure as a function of the source water temperature in the case of once-through cooling and ambient wet bulb temperature in the case of the closed-cycle system. The variation in plant efficiency and output can then be calculated from the variation in condensing pressure, and the difference in plant performance both on an annual average basis and during the hottest period of the year can be determined.

The following paragraphs outline the computational procedures involved in each step of the analysis and present the results of selected examples which are intended to cover the range of conditions encountered across the family of Phase II plant sites.

Determination of condensing pressure

The condensing pressure is determined by the condensing temperature maintained by the cooling system. The condensing temperature is given by the cold water inlet temperature to the condenser plus the temperature rise across the condenser ("range") plus the difference between the condenser hot water exit temperature and the condensing temperature (terminal temperature difference or "TTD"). Therefore, the condensing temperature in a once-through cooling system is given by

Once-through cooling: T_{cond} (°F) = T_{source} + Range + TTD

as shown schematically in Figure 7-1. For a once-through cooling system, the cold water inlet temperature is the source water temperature (T_{source}) available from the natural waterbody.

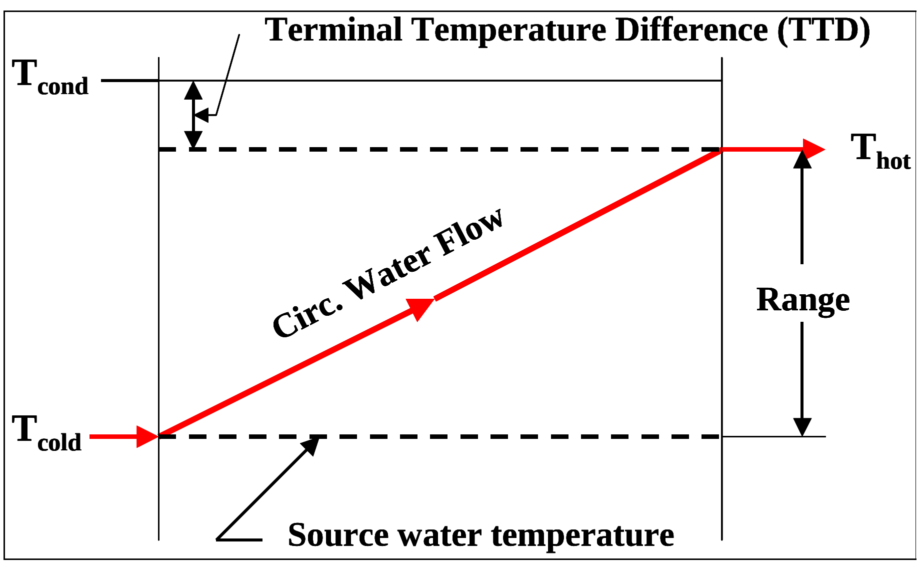

Figure 7-1
Once-through cooling operating configuration

For a closed cycle cooling system, the cold water temperature is the cooling tower cold water exit temperature given by the ambient wet bulb temperature ($T_{amb\ wb}$) plus the difference between the ambient wet bulb and the tower cold water temperature or the tower "approach" as shown in Figure 7-2.

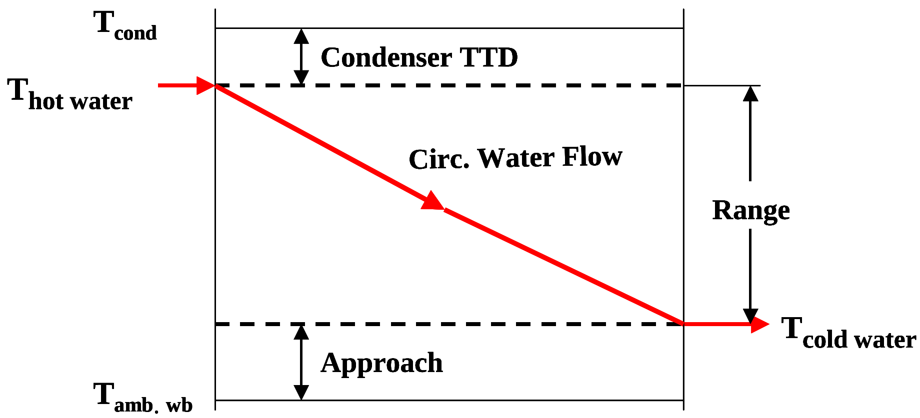

Figure 7-2
Closed-cycle cooling operating configuration

Therefore, the condensing temperature in a closed-cycle cooling system with a wet cooling tower is given by:

Closed-cycle cooling: $T_{cond}\,(^{\circ}F) = T_{amb\ wb} + Approach + Range + TTD$

The condensing pressure in each case is then given by the standard steam saturation equation where p_{sat} is expressed in inHga and T_{sat} in ºF.

$$p_{sat} = 0.0000000260 * T_{sat}^{4} - 0.00000492 * T_{sat}^{3} + 0.000667 * T_{sat}^{2} - 0.0317 * T_{sat} + 0.754$$

For the usual approach to retrofit where the circulating water flow rate and the condenser are left unchanged, the range and the TTD are the same for both the original and the retrofitted systems. Therefore, the difference in the condensing pressures is determined by the difference between the source water temperature and the ambient wet bulb plus the tower approach temperature.

$$T_{cond/closed\text{-}cycle} - T_{cond/once\text{-}through} = T_{amb,wb} + Approach - T_{source}$$

Once-through cooling---source water temperature

The average level and yearly variation in natural waterbody temperatures depends on the waterbody type and size, on the location of the cooling water intake structure and the region of the country. Consistently cold water is obtained from larger water bodies such as oceans and larger lakes and rivers in the northern parts of the country. Small rivers, small lakes and reservoirs and some inlets, bays and estuaries typically have higher average temperatures and high summertime temperatures. Exceptions exist. In the large water bodies, colder water is more consistently obtained with offshore, submerged intakes. Shoreline surface intakes, even at ocean-side plants, and particularly in protected bays or coves off the main ocean itself, can see much higher annual temperatures and significantly higher summertime temperatures. Figure 7-3 displays several examples.

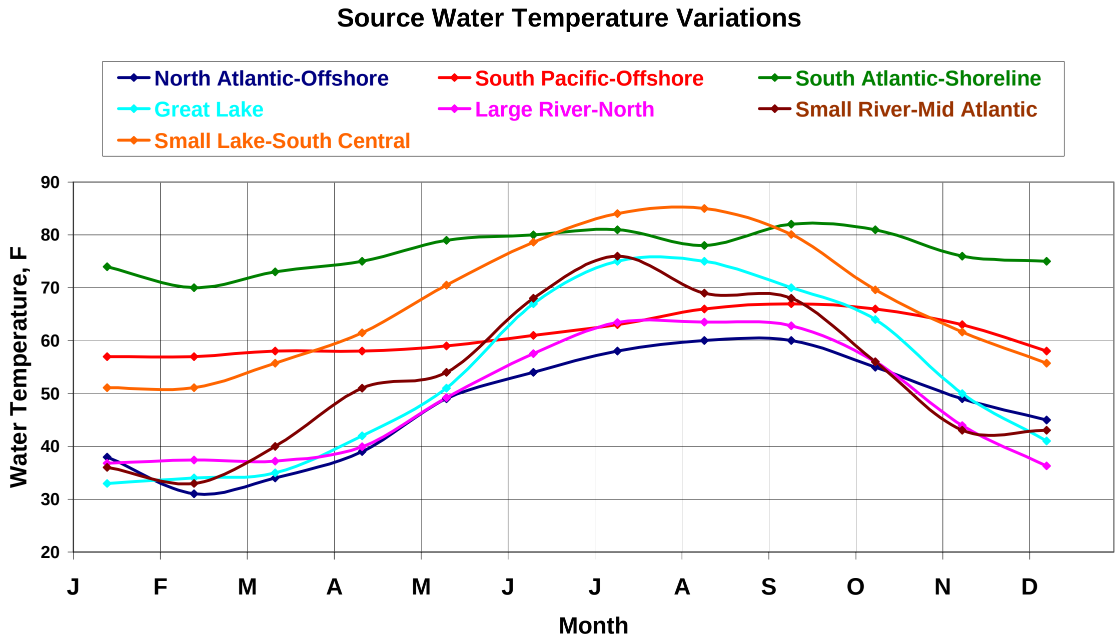

Figure 7-3
Variations in natural waterbody temperatures

Condenser range and TTD

The cooling water temperature rise across the condenser (the "range") is proportional to the condenser heat duty and inversely proportional to the cooling water flow rate. For a nominal plant heat rate of 10,000 Btu/kWh, the condenser heat load is around 5,000 Btu/kWh for a fossil plant and 6,500 Btu/kWh for a nuclear plant. As displayed in Figure 3-2, circulating water flow rates fall mostly in the range of 400 to 800 gpm/MW. This results in typical condenser temperature rises from approximately 12 to 25ºF for fossil plants and 15 to 30ºF for nuclear plants.

Most condenser design TTD's are in the range of 7 to 12ºF although in some instances, where a reliable year-round supply of cold water was assured, smaller condensers with higher TTD's were specified. Rare examples with TTD's as high as 25 to 30ºF were reported. For purposes of the following examples, the sum of the condenser temperature rise and the TTD will be assumed to range from approximately 20ºF (~12ºF + 7 ºF) to 40ºF (~ 30ºF + 12ºF).

For mid-range values of a 20ºF range and a 10ºF TTD, the corresponding condensing temperatures and condensing pressures for the source water sites shown in Figure 7-3 are shown in Figures 7-4 and 7-5.

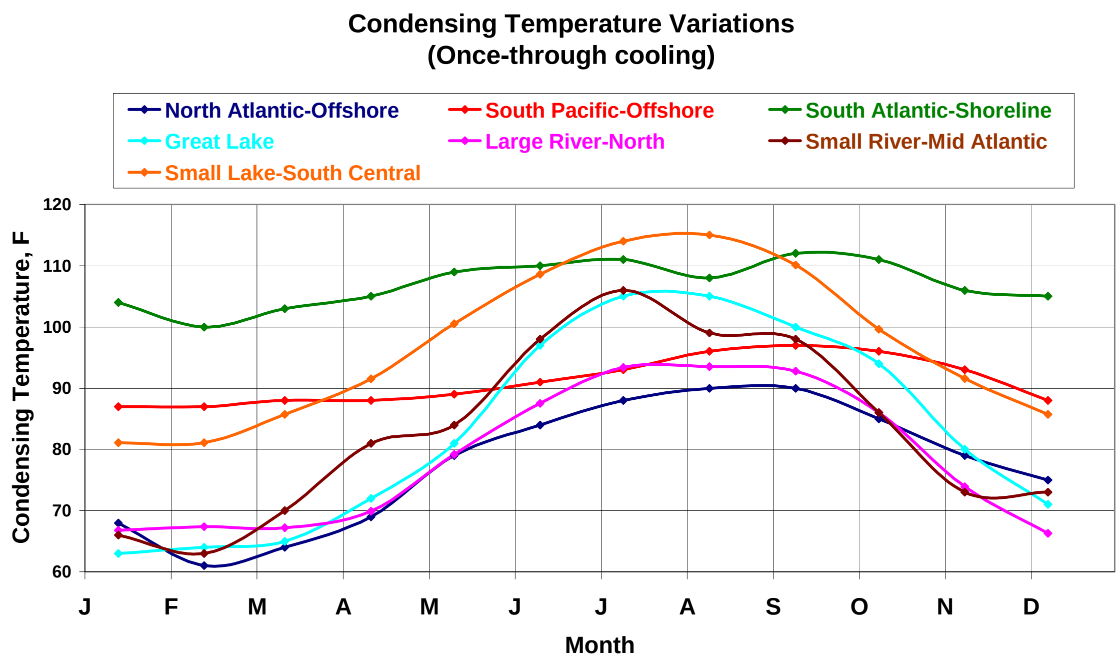

Figure 7-4
Variations in condensing temperatures for once-through cooled systems

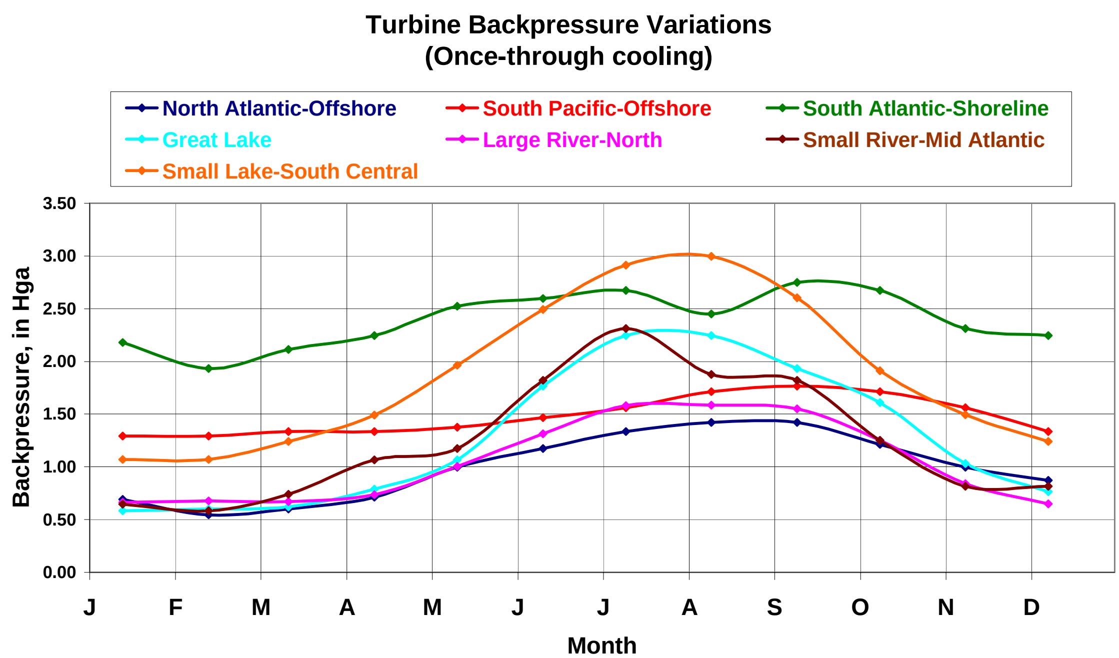

Figure 7-5
Variations in condensing pressures for once-through cooled systems

The range of operating turbine backpressure estimated for sites in each of the seven regions representing very different water bodies and climatic regions is from 0.5 to 3.0 in Hga. This corresponds precisely to the range of reported operating conditions from plants providing operating data for the study. An important feature of the result is that for many of these sites, there is a substantial variation in backpressure over the course of the year. The backpressures for the "Great Lakes" and the "Small River—Mid-Atlantic" sites vary from 0.5 in Hga in the winter to over 2.5 in Hga in the summer. The Small Lake-South Central site varies from 1.0 in Hga to 3.0 in Hga from winter to summer. As will be seen later in the analysis, this variation is important in evaluating the penalty associated with closed-cycle cooling retrofits.

Closed-cycle cooling—ambient wet bulb temperatures

As in the case of natural waterbody temperatures, the level and variability of ambient wet bulb temperature is a function not only of climatic region but also of very local conditions in the vicinity of the plant. Figure 7-6 displays the wet bulb temperature plots for the same seven sites. Where possible, plant data were used. When plant data were not available, public sources of meteorological data were used, typically taken at neighboring airports. (7-1, 7-2)

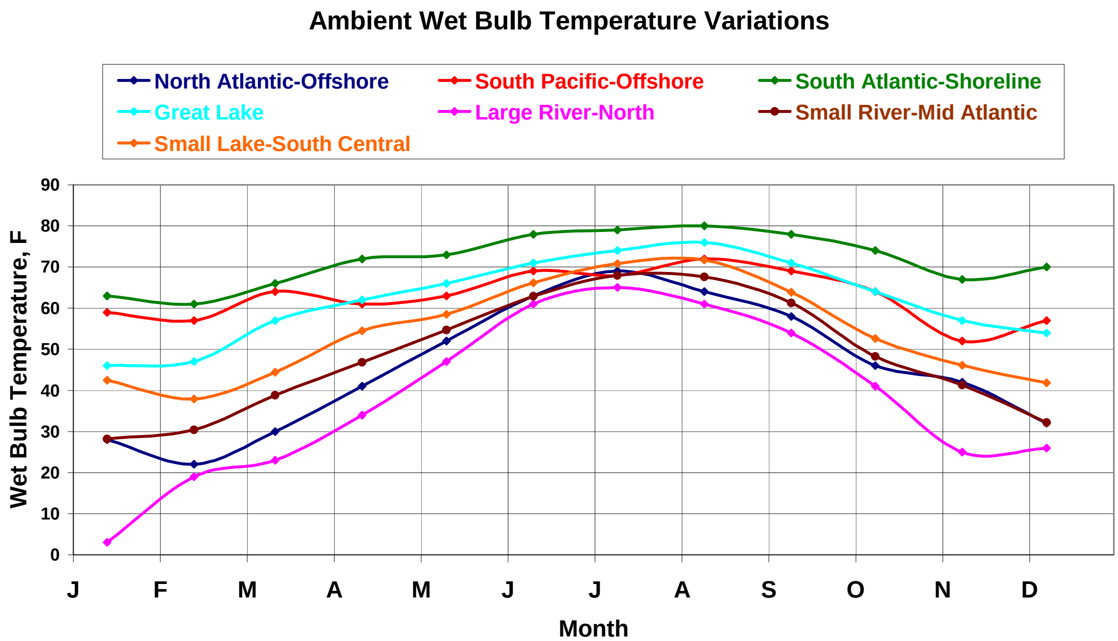

Figure 7-6
Variations in Ambient Wet Bulb Temperature

Local variations in wet bulb temperatures are usually grater than variations in local waterbody temperature. However, as will be seen, these variations do not affect changes in the condensing temperature as strongly as do source water temperature changes in once-through cooling systems.

Cooling tower approach temperature

The effectiveness of a tower in cooling water to a temperature close to the ambient wet bulb temperature is a function of cooling tower size, water-to-air flow ratio (L/G) and fill characteristics. As discussed previously, retrofits are assumed for purposes of this study to use mechanical-draft, counterflow cooling towers. Typical design approaches for these towers range from about 6 to 12 ºF with the lower approaches typically chosen in hotter, more humid regions and the higher approaches at cooler, drier sites. The following example will use a mid-range design approach of 9 ºF. The greatest likely error in the condensing temperature as a result of this generalization is +/- 3 ºF which will not affect the backpressure significantly. Therefore, the error in the estimated efficiency penalty will be small.

However, the approach at off-design operation is not the same as the approach at design conditions. The tower is normally designed for a “design approach” at the “0.4% wet bulb” at the site; that is, the wet bulb temperature which will be exceeded for only 0.4% of the hours of the year. Therefore, for nearly the entire year, the tower will be operating at an ambient wet bulb temperature well below the design value. As the ambient wet bulb decreases, the tower approach increases because the vapor pressure of water which drives the evaporation process decreases at lower temperatures. Therefore, for a given tower with a fixed fan power, water-to-air flow ratio (L/G), the cold water temperature leaving the tower will decrease more slowly than the ambient wet bulb. While the precise factor varies with tower design, a reasonable estimate is that the cold water temperature decreases by 0.5 ºF for each 1 ºF drop in wet bulb. The following calculations employ this approximation.

As noted above, the condenser range and TTD are unchanged from the original once-through system and estimates of condensing temperature and condensing pressure will assume the sum of range plus TTD to be 30 ºF as above.

Figures 7-7 and 7-8 show the estimated range of condensing temperature and pressure for the same seven sites as previously displayed for once-through cooling.

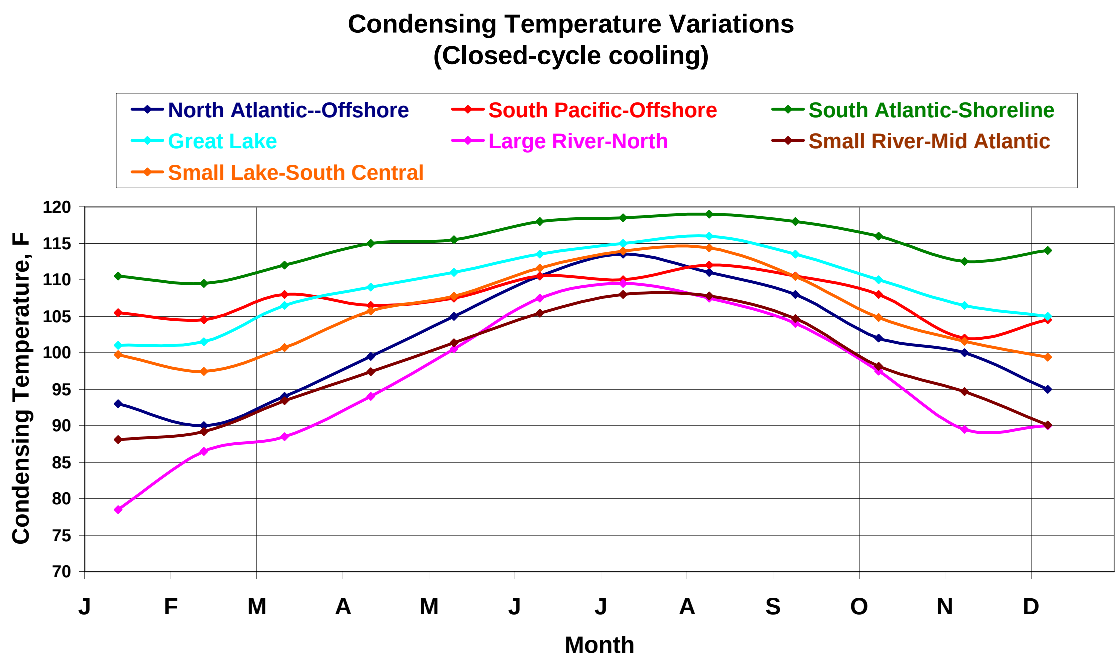

Figure 7-7
Variations in condensing temperatures for closed-cycle cooling systems

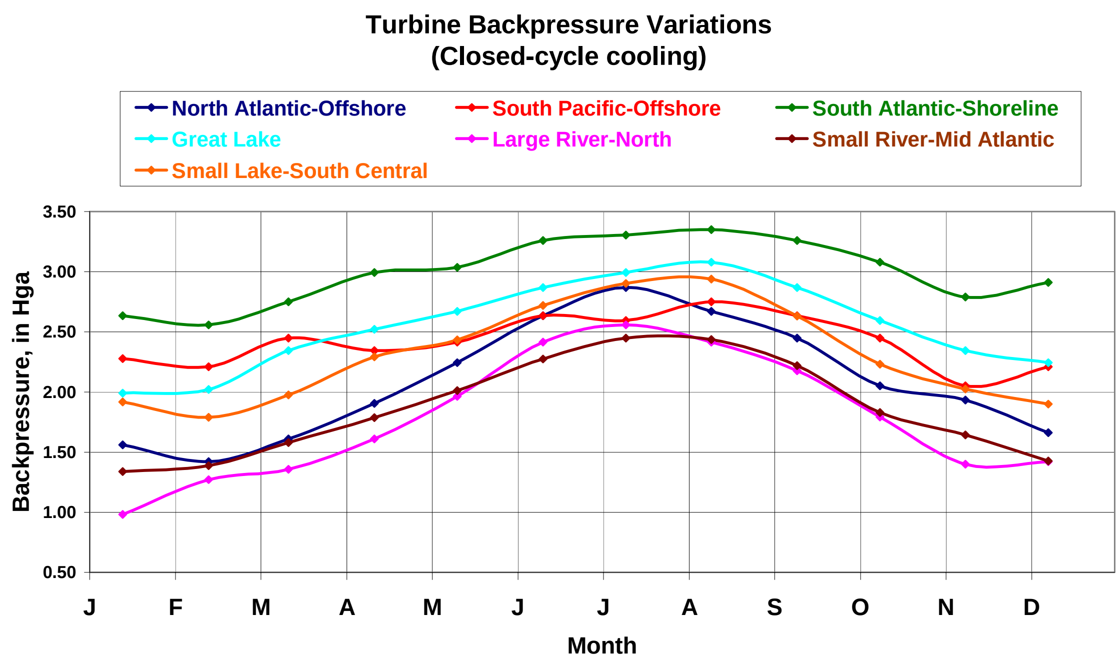

Figure 7-8
Variations in condensing pressures for closed-cycle cooling systems

The difference in cooling system performance can be quantified by the difference in the turbine exhaust pressures achieved by the two systems. Figure 7-9 displays the difference in the backpressures plotted in Figures 7-6, 7-7 and 7-8 (expressed as closed-cycle backpressure minus once-through backpressure) for each of the seven sites over the course of a year.

Several items are noteworthy.

- For most of the time at most of the sites the backpressure with closed-cycle cooling exceeds that with once-through cooling by 0.5 to 1.0 in Hga.
- In two instances, the "Great Lakes" site in the Spring and the "North Atlantic—Offshore" in the Summer, the difference exceeds 1.5 to 2.0 in Hga.
- In one instance, "Small Lake—South Central" there is a brief period during which the closed-cycle backpressure is less than the backpressure achieved with once-through cooling.

The values plotted in Figures 7-7, 7-8 and 7–9 are based on monthly average temperatures. Tables 7-3 and 7-4 provide the condensing temperatures and backpressure differences for the annual maximum ("hot day") condition (7-3) and the annual average conditions (7-4). It is interesting to note that, contrary to widely held belief, the performance penalty on the "hot day" is not always greater than the annual average. While it is at Sites 1 and 5, at all other sites the hot day penalty is approximately the same as, and in some cases significantly less than, the annual average penalty.

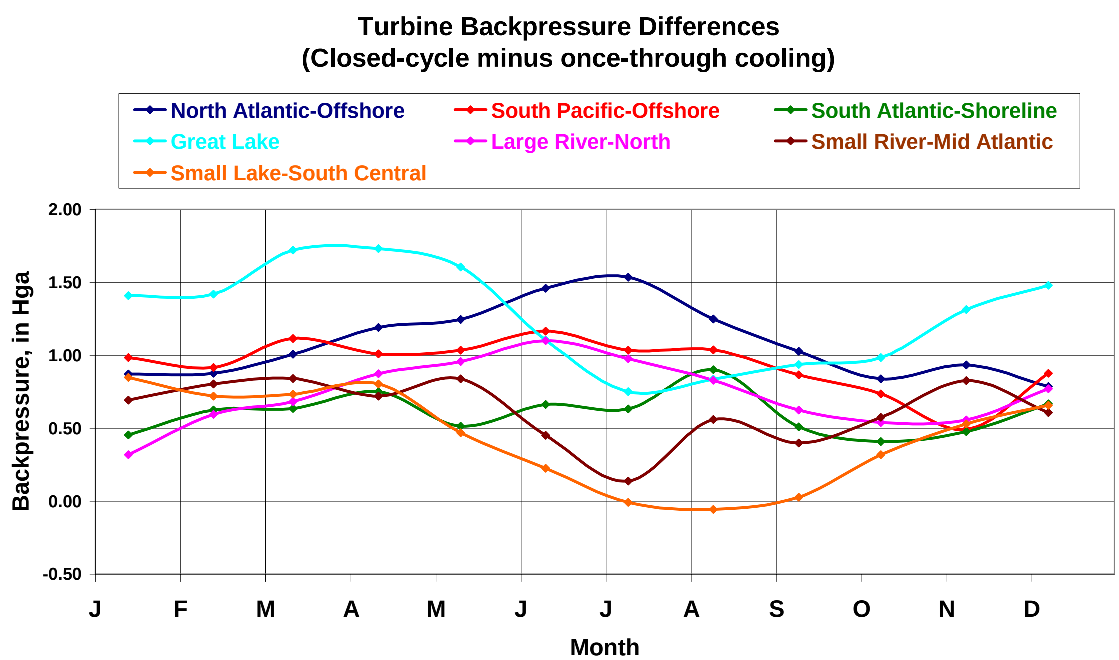

Figure 7-9
Backpressure differences---closed-cycle minus once-through cooling

The site numbers in Tables 7-3 and 7-4 correspond to the following locations:

1 North Atlantic--Off-shore

2 South Pacific--Offshore

3 South Atlantic--Shoreline intake

4 Great Lakes

5 Large River--North Central

6 Small River--Mid Atlantic

7 Small lake—South Central

Table 7-3
Summary of differences at "hot day" conditions

Site	1	2	3	4	5	6	7
$T_{source\ max,}$ F	67	70	86	83	69	80	89
$T_{amb\ wb\ max,}$ F	75	72	82	78	76	78	79
$T_{cond\ OTC,}$ F	97	100	116	113	99	110	119
$T_{cond\ Cl\ Cyc,}$ F	114	111	121	117	115	117	118
$p_{cond\ OTC,}$ in Hga	1.77	1.93	3.08	2.83	1.88	2.60	3.35
$p_{cond\ Cl\ Cyc,}$ in Hga	2.91	2.67	3.54	3.17	2.99	3.17	3.26
Difference	1.15	0.74	0.46	0.34	1.12	0.57	-0.09

Table 7-4
Summary of differences at annual average conditions

Site	1	2	3	4	5	6	7
$T_{source\ ave,}$ F	48	61	77	53	49	53	67
$T_{amb\ wb\ ave,}$ F	46	63	72	62	38	48	54
$T_{cond\ OTC,}$ F	78	91	107	83	79	83	97
$T_{cond\ Cl\ Cyc,}$ F	103	108	115	110	98	99	106
$p_{cond\ OTC,}$ in Hga	0.96	1.47	2.38	1.14	0.99	1.14	1.77
$p_{cond\ Cl\ Cyc,}$ in Hga	2.08	2.42	2.99	2.55	1.78	1.87	2.31
Difference	1.13	0.95	0.61	1.41	0.79	0.72	0.55

Effect of backpressure on performance

It remains to estimate how the increases in turbine backpressure affect plant efficiency and output. General information was obtained from a standard reference handbook (7-13) and is summarized in Table 7-5 and plotted in Figures 7-10 through 7-13. Table 7-5 groups a range of turbine sizes by steam throttle pressure. The deleterious effect of increased exhaust pressure on turbine performance is related to losses in the last stages of the turbine. The percent loss at an exhaust pressure of 5 in Hga, for turbines designed for 1.5 in Hga shows an inverse linear relationship to exhaust plane energy flux expressed as kW/ft^2. This is shown in Figure 7-10.

The variation in lost turbine output at any increased turbine exhaust pressure is quite large as the data plotted for 12 turbine designs in Figure 7-11 shows. The variation in the heat rate increase is reasonably bounded by the upper and lower lines on Figure 7-11. In general, larger turbines with higher throttle pressures exhibit less loss with increasing exhaust pressure than do smaller, lower throttle pressure designs. The range of lost output for an exhaust pressure of 3.5 in Hga (a 2 in Hga increase over the design pressure of 1.5 in Hga) is from 1.5 to 4.%.

Table 7-5
Turbine performance characteristics (Summarized from Ref. 7- 13)

Nominal rating	Steam conditions			Turbine compound, 3,600 rpm last-stage buckets				Boiler feed pump drive	Net heat rate, Btu/kWh at rated load and steam conditons and at exhaust pressure, in Hga					% increse above 1.5 in Hga in net heat rate at rated load and and at exhaust pressure				
MW @ 1.5 in Hga	Throttle pressure	Temp	Reheat Temp	No. of rows	Length	Exhaust area	Approx kW/ft2											
MW	psig	F	F		in	ft2	kW/ft2		1.5	2	3	4	5	1.5	2	3	4	5
150	1,800	1,000	1,000	2	26	82	1,829	**Motor**	8,010	8,060	8,230	8,440	8,630	0	0.006	0.027	0.054	0.077
235	1,800	1,000	1,000	2	26	82	2,866	**Motor**	8,240	8,240	8,290	8,380	8,500	0	0.000	0.006	0.017	0.032
250	1,800	1,000	1,000	2	30	111	2,252	**Motor**	8,080	8,100	8,220	8,400	8,620	0	0.002	0.017	0.040	0.067
250	1,800	1,000	1,000	2	30	111	2,252	Turbine	8,030	8,060	8,200	8,390	8,610	0	0.004	0.021	0.045	0.072
250	2,400	1,000	1,000	2	30	111	2,252	Turbine	7,850	7,890	8,030	8,240	8,450	0	0.005	0.023	0.050	0.076
500	2,400	1,000	1,000	4	30	222	2,252	Turbine	7,790	7,830	7,970	8,170	8,370	0	0.005	0.023	0.049	0.074
700	2,400	1,000	1,000	4	33.5	264	2,652	Turbine	7,860	7,870	7,970	8,130	8,320	0	0.001	0.014	0.034	0.059
1000	2,400	1,000	1,000	6	30	334	2,994	Turbine	7,920	7,930	8,000	8,100	8,250	0	0.001	0.010	0.023	0.042
500	3.,500	1,000	1,000	4	30	222	2,252	Turbine	7,620	7,660	7,820	8,030	8,220	0	0.005	0.026	0.054	0.079
700	3.,501	1,000	1,000	4	33.5	264	2,652	Turbine	7,670	7,690	7,810	7,980	8,170	0	0.003	0.018	0.040	0.065
1000	3.,502	1,000	1,000	6	30	334	2,994	Turbine	7,710	7,730	7,810	7,940	8,090	0	0.003	0.013	0.030	0.049
1100	3.,503	1,000	1,000	6	33.5	397	2,771	Turbine	7,680	7,700	7,810	7,960	8,140	0	0.003	0.017	0.036	0.060

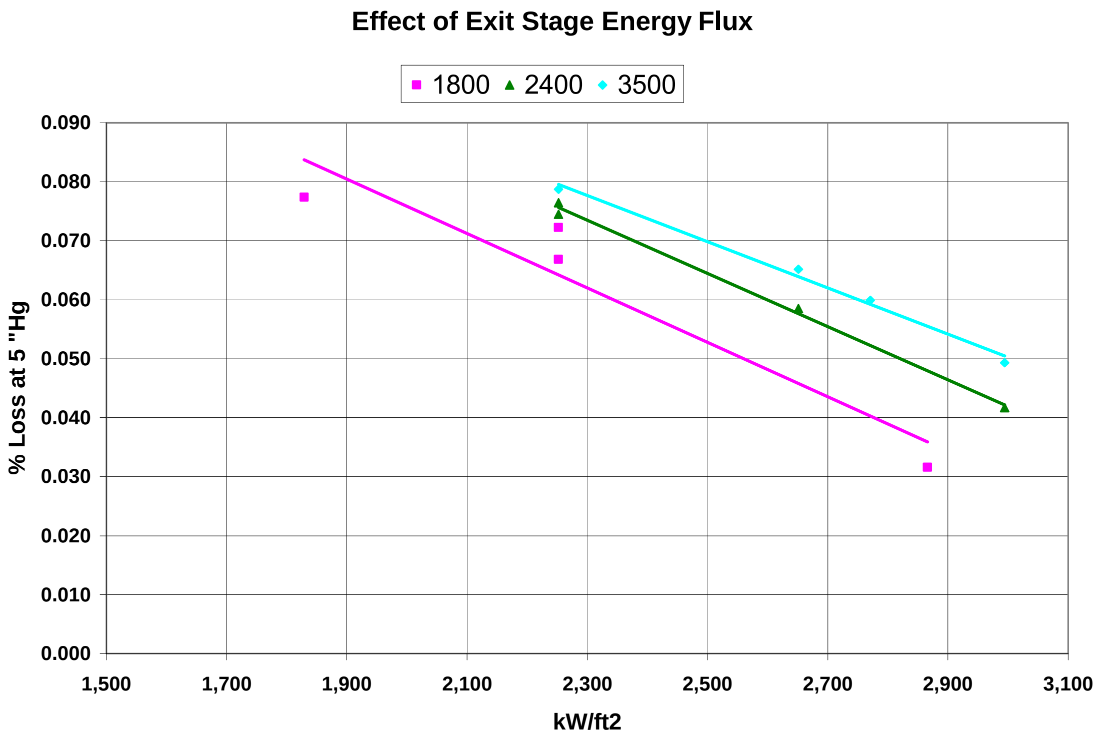

Figure 7-10
Effect of last stage conditions on turbine output loss

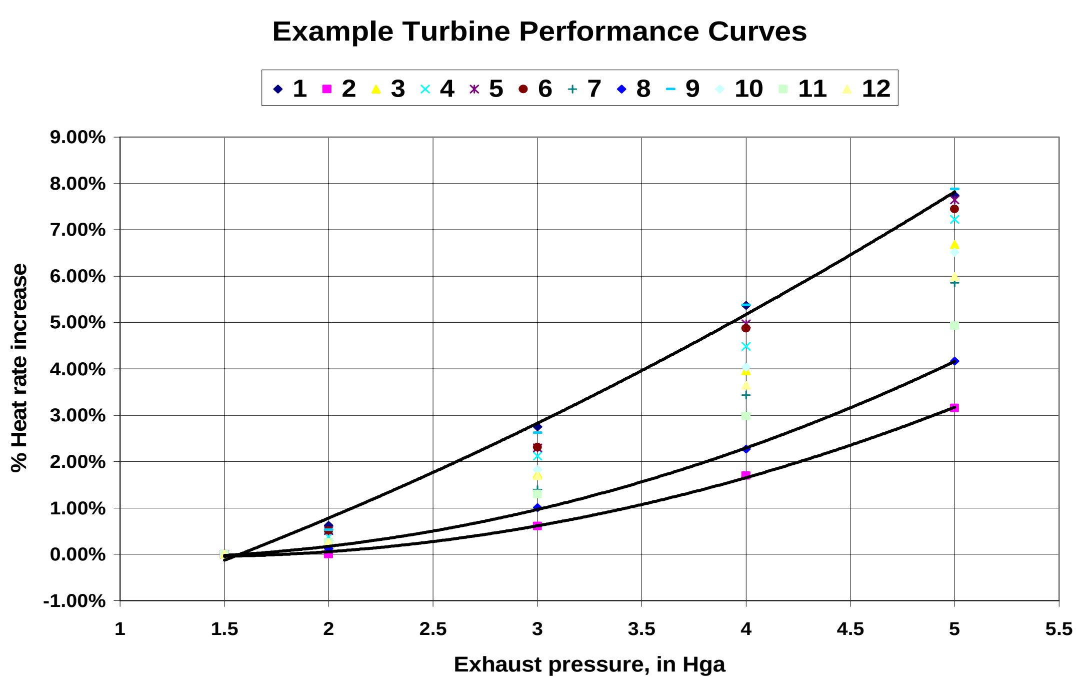

Figure 7-11
Range of exhaust pressure effect on turbine output loss

Figure 7-12 shows similar results for "textbook" examples for "typical" coal and nuclear plant turbines. The nuclear turbines have a much lower throttle pressure and show significantly higher lost output with increasing exhaust pressure.

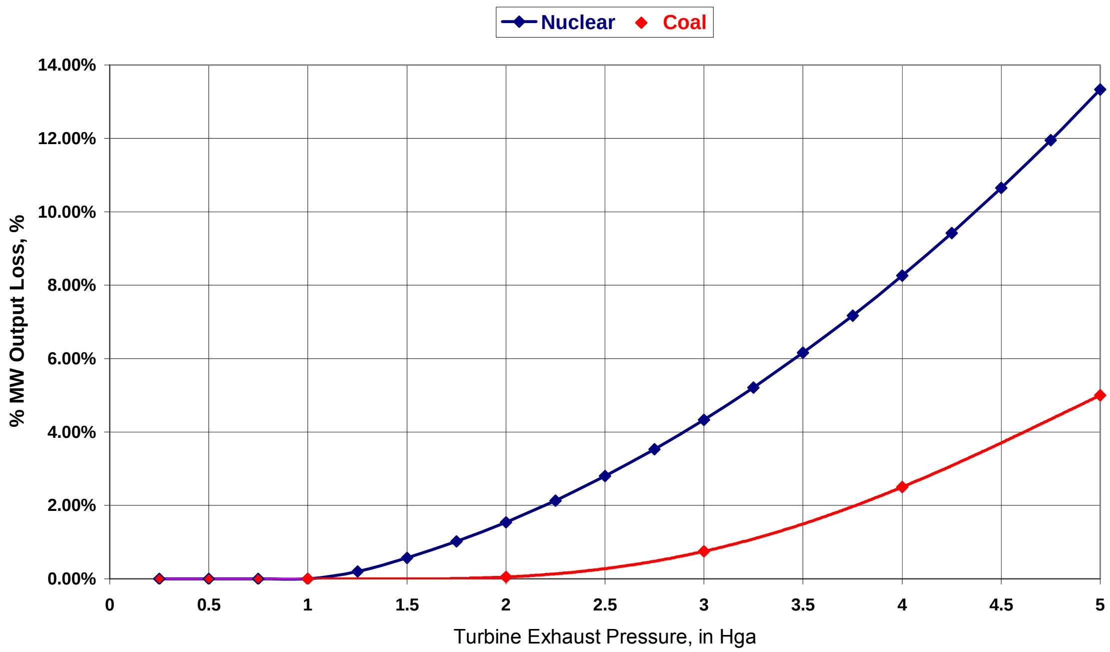

Figure 7-12
Heat Rate (Plant Performance vs. Turbine Backpressure) Curve

Additional consideration is the variation in sensitivity to backpressure with turbine steam flow or plant load. Figure 7-13 shows the much higher lost output expressed as "% Change in Heat Rate" for a range of steam flows with full load operation showing the least effect of increasing backpressure.

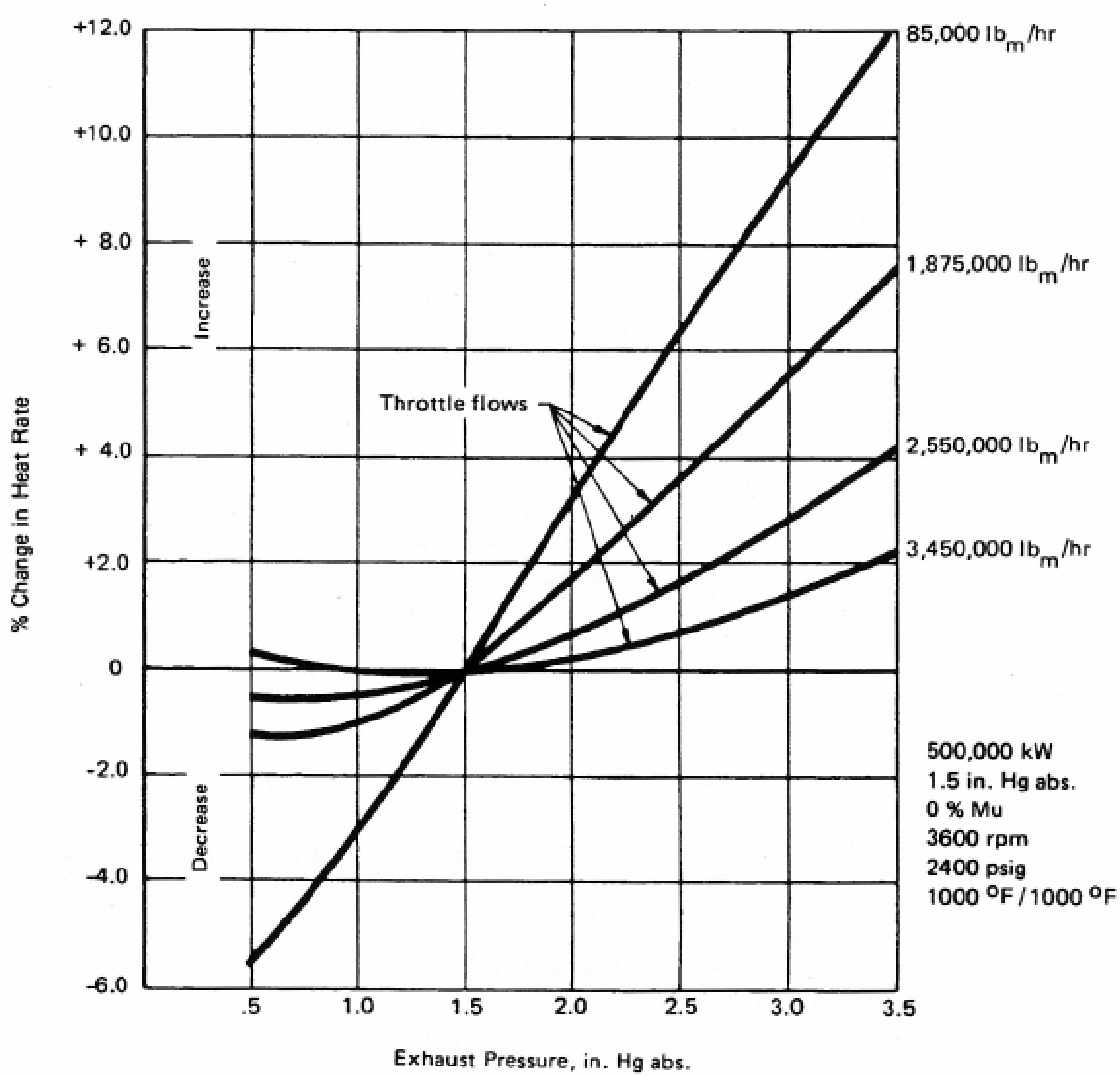

Figure 7-13
Effect of steam flow on turbine output loss (from Ref. 7-14)

Finally, the questionnaires distributed to Phase II plants (See Appendix C) included a request for turbine design operating conditions and the reduction in capacity with elevated backpressures. (See Worksheet 12; "Unit Cooling System Data") While most respondents omitted this information, approximately 40 plants representing over 80 units did provide it. The responses are listed in Table 7-6.

The data were divided into 6 groups by design backpressure from 0.5 to 3.5 in Hga and the loss in output, expressed as a percent of design capacity, was plotted vs. turbine backpressure in Figure 7-14. As seen in the plots, there is little consistency to the data.

Table 7-6
Plant data on effect of backpressure on performance

Plant/Unit ID	Fuel	Turbine Backpressure, in Hga			Performance Loss (expressed in MW, kW or Btu/kWh)			% MW Loss		
		Design	Design + 1	Design + 2	MW des	MWdes1	MWdes2	Des	Des + 1	Des + 2
F510/1	Coal	0.5	1.5	2.5	324	320	315	0.00%	1.36%	2.78%
F510/2	Coal	0.5	1.5	2.5	324	320	315	0.00%	1.36%	2.78%
F277/7	Coal	1	2.0	3.0	238	234	230	0.00%	1.68%	3.36%
F277/8	Coal	1	2.0	3.0	348	339	331	0.00%	2.59%	4.89%
F296/7	Coal	1	2.0	3.0	102	102	99	0.00%	0.00%	2.94%
F303/1	Coal	1.0	2.0	3.0	77	74	69	0.00%	3.90%	10.39%
F339/1	Coal	1.0	2.0	3.0	7,263	7,437	7,684	0.00%	2.40%	5.80%
F378/1	Coal	1.0	2.0	3.0	170	162	158	0.00%	4.33%	6.81%
F382/19	Coal	1.0	2.0	3.0	348	338	328	0.00%	2.87%	5.75%
F451/1	Coal	1.0	2.0	3.0	175	169	164	0.00%	3.49%	6.51%
F451/2	Coal	1	2.0	3.0	177	170	164	0.00%	3.73%	7.40%
F451/3	Coal	1	2.0	3.0	291	282	272	0.00%	3.16%	6.46%
F451/4	Coal	1	2.0	3.0	577	566	552	0.00%	1.99%	4.35%
F505/1	Coal	1.0	2.0	3.0	136	134	130	0.00%	1.47%	4.78%
F505/2	Coal	1.0	2.0	3.0	136	134	130	0.00%	1.47%	4.78%
F226/6	Coal	1.12	2.1	3.1	341	325		0.00%	4.69%	
F505/3	Coal	1.13	2.1	3.1	182	180	177	0.00%	1.10%	2.88%
F505/4	Coal	1.13	2.1	3.1	182	180	177	0.00%	1.10%	2.88%
F546/7	Coal	1.18	2.2	3.2	359	350	339	0.00%	2.45%	5.52%
F378/2	Coal	1.25	2.3	3.3	250	241	235	0.00%	3.49%	6.08%
F546/8	Coal	1.3	2.3	3.3	384	374	365	0.00%	2.60%	4.95%
Fos 6/1	Coal	1.4	2.4	3.4	260	256	250	0.00%	1.69%	3.77%
Fos 6/2	Coal	1.4	2.4	3.4	360	348	338	0.00%	3.31%	6.17%
Fos 1/3	Coal	1.44	2.4	3.4	148	147	146	0.00%	0.68%	1.49%
F241/1	Coal	1.49	2.5	3.5	na	na	na	0%	2%	4.25%
F241/2	Coal	1.49	2.5	3.5	na	na	na	0%	2%	4.25%
F303/2	Coal	1.5	2.5	3.5	80	77	72	0.00%	3.75%	10.00%
F303/3	Coal	1.5	2.5	3.5	80	77	72	0.00%	3.75%	10.00%
F306/3	Coal	1.5	2.5	3.5	105	102	100	0.00%	2.86%	4.76%
F383/1	Coal	1.5	2.5	3.5	228,860	228,144	225,868	0.00%	0.31%	1.31%
F383/2	Coal	1.5	2.5	3.5	468,097	458,974	451,501	0.00%	1.95%	3.55%
F481/1	Coal	1.5	2.5	3.5	808	804	788	0.00%	0.50%	2.49%
F481/2	Coal	1.5	2.5	3.5	833	826	804	0.00%	0.90%	3.48%
F481/3	Coal	1.5	2.5	3.5	833	826	804	0.00%	0.90%	3.48%
F481/4	Coal	1.5	2.5	3.5	813	809	793	0.00%	0.50%	2.49%
F251/8	Coal	1.72	2.7	3.7	na	na	na	0.00%	1.90%	4.40%
Fos 1/2	Coal	1.87	2.9	3.9	82	81	80	0.00%	1.10%	2.44%
Fos 1/1	Coal	1.9	2.9	3.9	81	80	78	0.00%	0.99%	2.61%
Fos 6/3	Coal	1.91	2.9	3.9	835	825	807	0.00%	1.15%	3.34%
F181/1	Coal	2.0	3.0	4.0	195	192	189	0.00%	1.54%	3.08%
F251/7	Coal	2	3.0	4.0	na	na	na	0	1.30%	4.20%
F268/1	Coal	2.0	3.0	4.0	656	642	630	0.00%	2.13%	3.96%
F271/1	Coal	2.0	3.0	4.0	7,811	8,006	8,123	0.00%	2.50%	3.99%
F407/1	Coal	2.0	3.0	4.0	395,703	391,011	384,178	0.00%	1.19%	2.91%
F407/2	Coal	2.0	3.0	4.0	526,160	523,022	517,874	0.00%	0.60%	1.57%
F211/1	Coal	2.1	3.1	4.1	115	115	115	0.00%	0.17%	0.43%
F211/2	Coal	2.1	3.1	4.1	115	115	115	0.00%	0.17%	0.43%
F248/1	Coal	2.5	3.5	4.5	535	520	485	0.00%	2.80%	9.35%
F248/2	Coal	2.5	3.5	4.5	535	520	485	0.00%	2.80%	9.35%
F380/1	Coal	2.7	3.7	4.7	190,908	189,581	186,981	0.00%	0.70%	2.06%
F380/2	Coal	2.75	3.8	4.8	185,156	182,780	180,288	0.00%	1.28%	2.63%
F318/5	Coal	2.9	3.9	4.9	75,000	74,169	73,318	0.00%	1.11%	2.24%
F318/6	Coal	2.9	3.9	4.9	162,000	160,137	158,436	0.00%	1.15%	2.20%
F267/2	Coal	3	4.0	5.0	487	479	469	0.00%	1.70%	3.80%
F425/3	Coal	3.66	4.7	5.7	685,668	677,538	668,292	0.00%	1.19%	2.53%
F425/2	Coal	3.77	4.8	5.8	684,950	678,168	666,943	0.00%	0.99%	2.63%
F425/1	Coal	4.0	5.0	6.0	376,791	371,956	365,108	0.00%	1.28%	3.10%

Table 7-6 (continued)
Plant data on effect of backpressure on performance

Plant/Unit ID	Fuel	Turbine Backpressure, in Hga			Performance Loss (expressed in MW, kW or Btu/kWh)			% MW Loss		
		Design	Design + 1	Design + 2	MW des	MWdes1	MWdes2	Des	Des + 1	Des + 2
N233	Nucl	1.7	2.7	3.7	1,296	1,288	1,265	0.00%	0.61%	2.37%
N513	Nucl	2.0	3.0	4.0	790	769	748	0.00%	2.66%	5.32%
N100	Nucl	3.31	4.3	5.3	992	985	978	0.00%	0.71%	1.41%
N100	Nucl	3.31	4.3	5.3	992	985	978	0.00%	0.71%	1.41%
F306/1	Oil/gas	1.5	2.5	3.5	239	237	236	0.00%	0.84%	1.26%
F306/2	Oil/gas	1.5	2.5	3.5	242	240	239	0.00%	0.83%	1.24%
F280/1	Oil/gas	2.0	3.0	4.0	131,797	129,086	126,363	0.00%	2.06%	4.12%
F280/2	Oil/gas	2.0	3.0	4.0	132,320	129,598	126,865	0.00%	2.06%	4.12%
F280/3	Oil/gas	2.0	3.0	4.0	213,773	211,447	207,950	0.00%	1.09%	2.72%
F281/1	Oil/gas	2	3.0	4.0	277,000	273,925	267,444	0.00%	1.11%	3.45%
F281/2	Oil/gas	2	3.0	4.0	277,000	273,925	267,444	0.00%	1.11%	3.45%
F347/1	Oil/gas	2.0	3.0	4.0	37,565	36,649	35,607	0.00%	2.44%	5.21%
F347/2	Oil/gas	2.0	3.0	4.0	37,323	36,413	35,377	0.00%	2.44%	5.21%
F347/3	Oil/gas	2.0	3.0	4.0	83,555	81,517	79,199	0.00%	2.44%	5.21%
F450/1	Oil/gas	2.0	3.0	4.0	527,911	525,285	520,109	0.00%	0.50%	1.48%
F450/2	Oil/gas	2.0	3.0	4.0	527,911	525,285	520,109	0.00%	0.50%	1.48%
F194/1	Oil/gas	2.5	3.5	4.5	156,000	153,863	151,492	0.00%	1.37%	2.89%
F394/1	Oil/gas	2.5	3.5	4.5	135,516	133,348	131,112	0.00%	1.60%	3.25%
F394/2	Oil/gas	2.5	3.5	4.5	137,002	134,834	132,598	0.00%	1.58%	3.21%
F449/1	Oil/gas	2.5	3.5	4.5	225,000	221,625	218,475	0.00%	1.50%	2.90%
F449/2	Oil/gas	2.5	3.5	4.5	225,000	221,625	218,475	0.00%	1.50%	2.90%
F449/3	Oil/gas	2.5	3.5	4.5	402,000	397,176	389,337	0.00%	1.20%	3.15%
F449/4	Oil/gas	2.5	3.5	4.5	402,000	397,176	389,337	0.00%	1.20%	3.15%
F537/1	Oil/gas	2.5	3.5	4.5	402,000	397,176	389,337	0.00%	1.20%	3.15%
F537/2	Oil/gas	2.5	3.5	4.5	402,000	397,176	389,337	0.00%	1.20%	3.15%

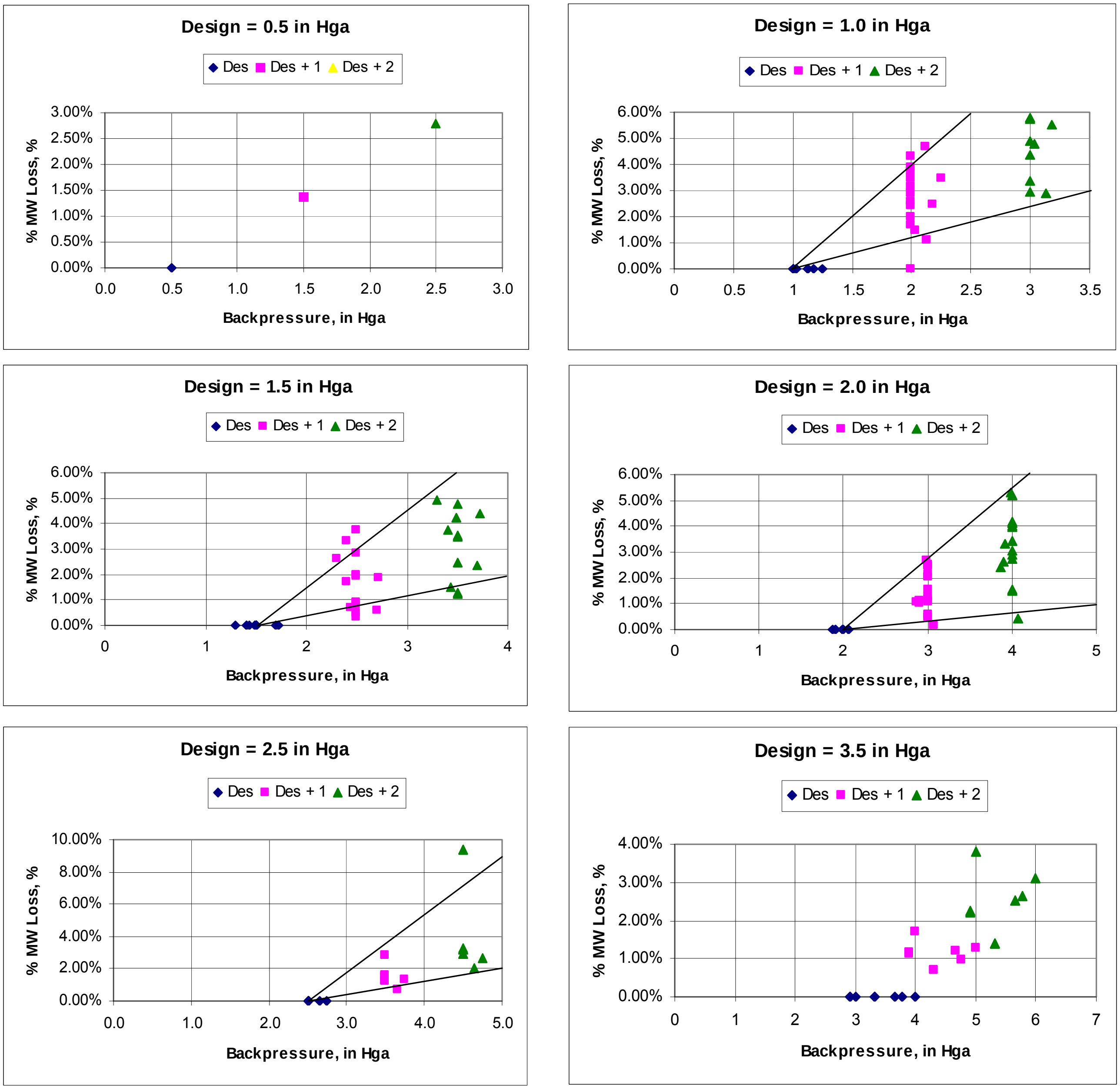

Figure 7-14
Performance Loss Data

Attempts to discern relationships with turbine size or age (no other characterizing information was available) were unsuccessful. Therefore, the following approach was adopted to develop estimates of the reduction in turbine performance as a function of increased exhaust pressure. The data sets for each of the design backpressures were bracketed with linear boundaries representing “high” and “low” coefficients of % loss per in Hga of backpressure increase. The range from all 6 plots gave 3.5% MW loss per in Hga for the maximum effect and 0.3% MW loss per in Hga for the minimum. An intermediate value of 1.9% MW loss per in Hga was inferred from the two extremes.

The coefficients were then applied to the "Hot Day" and "Annual Average" backpressure differences tabulated in Table 7-3 and 7-4. The results for Performance Penalty at hot day and annual average conditions are tabulated in Tables 7-7 and 7-8.

Table 7-7
Turbine Performance Loss at Hot Day Conditions

% Output Loss---"Hot Day" Conditions							
Site	1	2	3	4	5	6	7
Maximum	4.0%	2.6%	1.6%	1.2%	3.9%	2.0%	-0.3%
Intermediate	2.2%	1.4%	0.9%	0.6%	2.1%	1.1%	-0.2%
Minimum	0.34%	0.22%	0.14%	0.10%	0.34%	0.17%	-0.03%

Table 7-8
Turbine Performance Loss at Annual Average Conditions

% Output Loss---Annual Average Conditions							
Site	1	2	3	4	5	6	7
Maximum	4.0%	3.3%	2.2%	4.9%	2.8%	2.5%	1.9%
Intermediate	2.1%	1.8%	1.2%	2.7%	1.5%	1.4%	1.0%
Minimum	0.34%	0.28%	0.18%	0.42%	0.24%	0.22%	0.16%

Under some conditions, both the hot day and the annual average performance penalties can equal or exceed 4%. However, the typical annual average penalty at most sites is in the range of 1.0 to 2.0% annual average penalty at most sites. This is consistent with previous estimates (7-4, 7-5). In addition, the "hot day" penalties are generally less than had been assumed and also are typically in the 1 to 2% range.. This appears to result from the reported annual variation in natural waterbody source water temperature showing significant summertime increases which had perhaps not been accounted for in previous generalized analyses.

Additionally, the financial impact of a decrease in plant efficiency and peak day output is a complex function of the plant operating profile and capacity factor and the company contractual arrangements with the grid. Precise cost determinations in this area are beyond the scope of this study. However, some general approximation assuming industry average factors can be made as will be discussed in Chapter 8.

For purposes of clarification, two illustrative examples for two distinct climatic zones are presented below.

Lake source in mid-Atlantic state

Figure 7-15 shows the seasonal variation in the temperature of cooling water available from the lake currently used as the source of water for once-through cooling, the ambient wet-bulb temperature and the resulting cold water temperature from the tower.

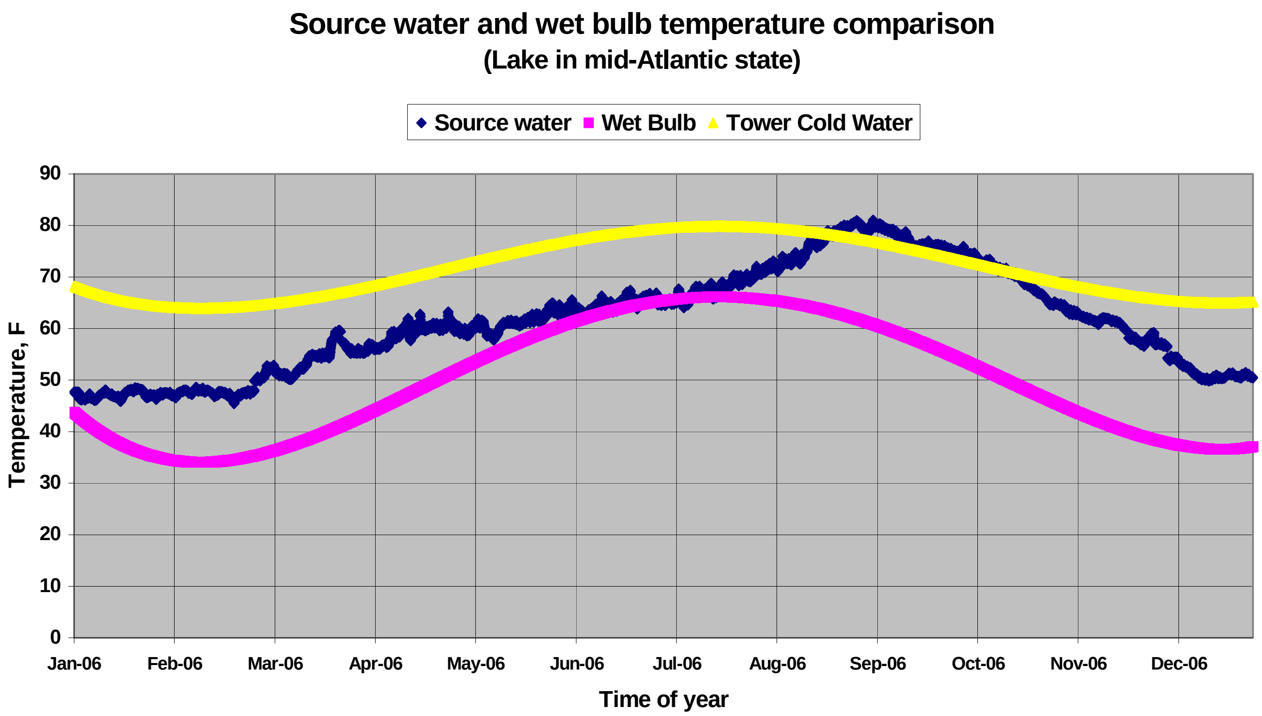

Figure 7-15
Temperature comparisons in mid-Atlantic state with lake water source

Based on the design point of the existing once-through cooling system, the comparative turbine backpressures over the course of the year are shown in Figure 7-16. Note that in both plots the closed-cycle curves are smoothed compared to the once-through curves. This is a result of having daily values available for the once-through operation, while having only monthly average values for the closed-cycle conditions which were then approximated with a polynomial curve fit. This can result in excursions of the ambient wet bulb temperature and the corresponding loss in turbine performance above the monthly average value. Similarly there will be periods when the ambient wet bulb and the loss in turbine performance will be less on an hourly basis. Therefore, this analysis may not capture the full impact of retrofitting to closed-cycle cooling.

In this example, the backpressure with closed-cycle cooling is well above that with once-through cooling for most of the year, but approximately the same for the hottest period. This is a result of the lake water temperature rising to very high levels in the late summer, while the wet-bulb temperature varies more moderately during the same period. In this instance, the closed-cycle system produces a slightly lower backpressure for a brief period. Throughout the year, the average backpressure on closed-cycle cooling is 0.41 in Hga higher than that with once-through cooling with a maximum difference of 0.81 in Hga in early July.

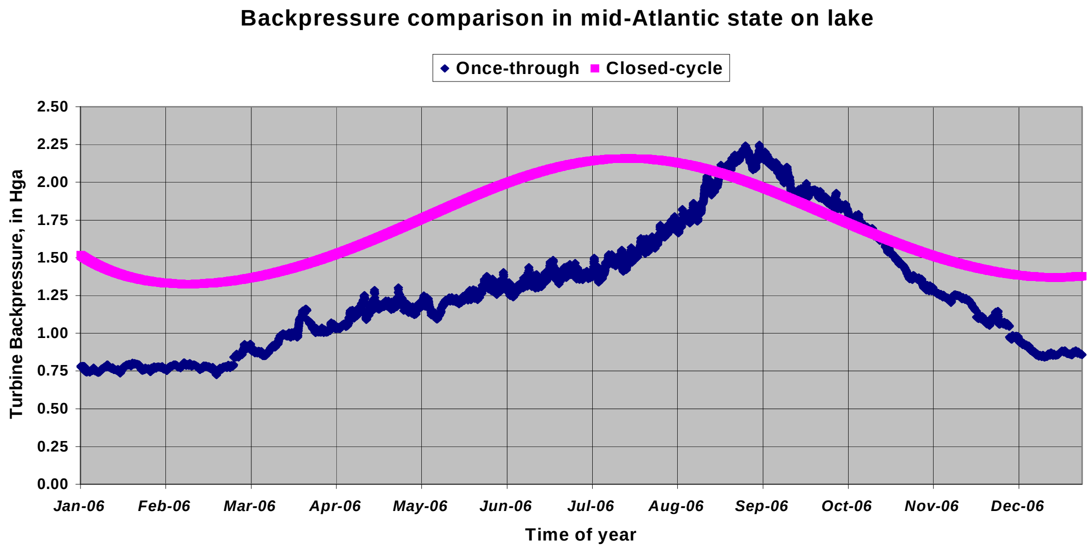

Figure 7-16
Backpressure comparisons in mid-Atlantic state with lake water source

Ocean cooling in the Northeast

Comparable curves are shown for a different set of source water and climatic conditions in Figures 7-17 and 7-18.

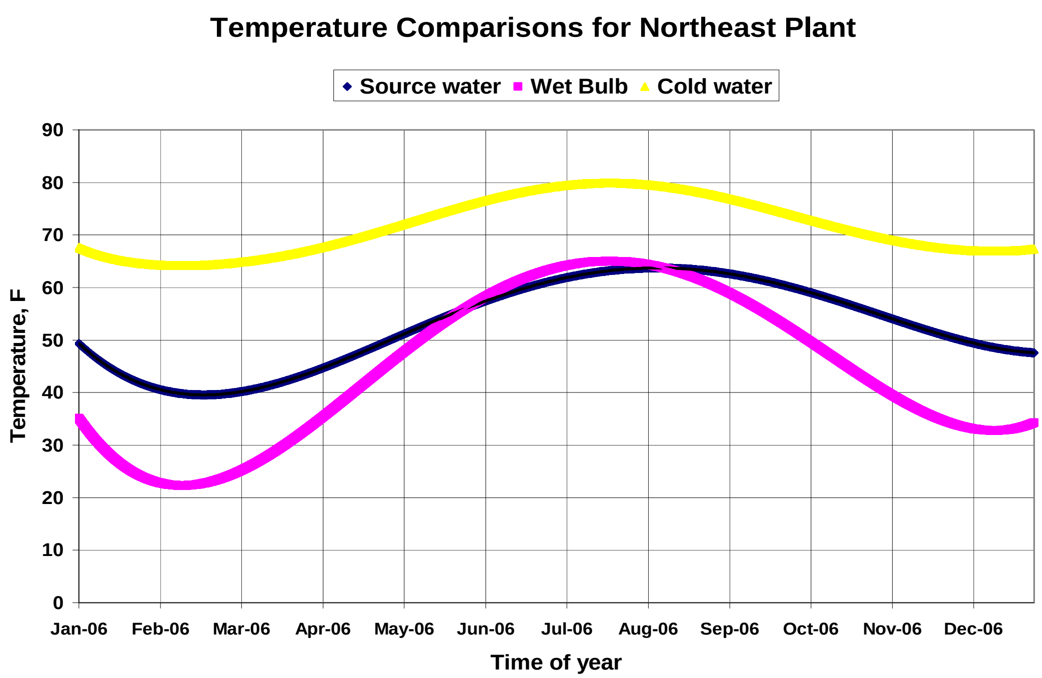

Figure 7-17
Cooling water temperature comparison with ocean cooling in Northeast

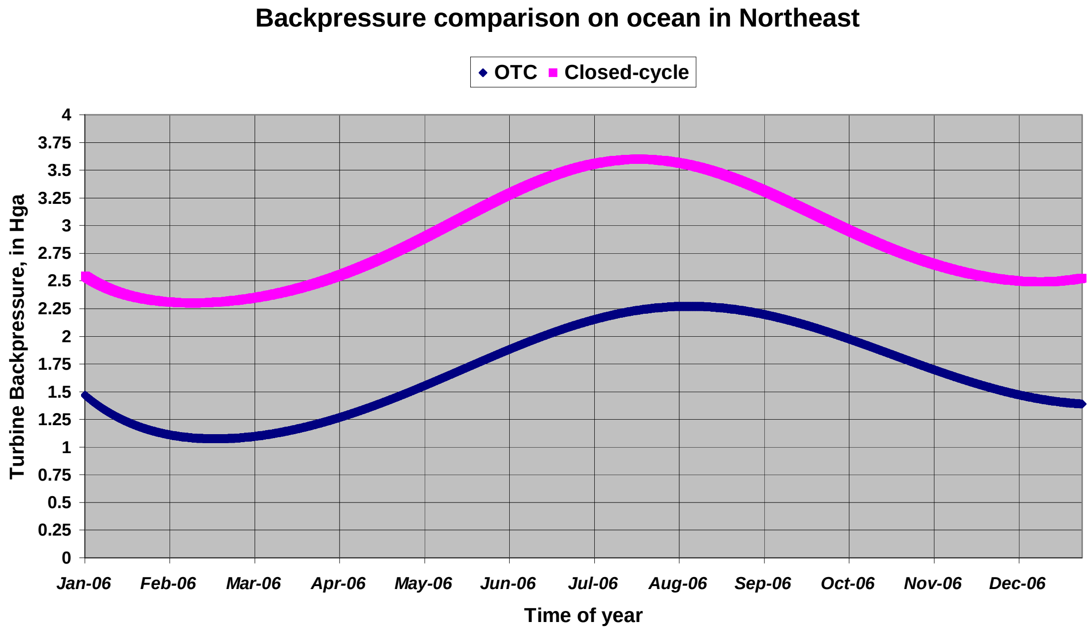

Figure 7-18
Backpressure comparison with ocean cooling in Northeast

In the example shown in Figure 7-17, the backpressure with closed-cycle cooling is well above that with once-through cooling for the entire year. This is a result of the ocean water temperature being consistently low throughout the year with little variation, while the wet-bulb temperature varies over a greater range during the same period. On average throughout the year, the average backpressure on closed-cycle cooling is 1.2 in Hga higher than that with once-through cooling with a maximum difference of 1.4 in Hga in mid-June.

The examples in Figures 7-15 through 7-17 show the effect on turbine exhaust pressure. The resultant effect on plant efficiency and output as a result of increases in backpressure depends strongly on the characteristics of the steam turbine as discussed earlier. The slope of the heat rate vs. backpressure curve varies with the age of the turbine and the backpressure for which it was originally optimized. A typical range from a number of sources is from 1 to 2% reduction in output at full load steam flow for each 1 inch Hga increase in backpressure. The curve is non-linear and the slope increases with increasing backpressure. Therefore, a difference of 1 inch Hga in backpressure results in a larger reduction at higher backpressures. This exacerbates the situation on hot days when the backpressure is at its highest on either cooling system.

Costs of downtime

Certain elements of a cooling system retrofit can be performed while the plant continues to operate on the existing once-through cooling system. These would normally include site preparation, basin construction, and the erection of a new cooling tower and the installation of required electrical gear, motor control centers, and other auxiliary equipment needs. Large portions of the installation of new circulating water piping and pumps and the new make-up and blowdown lines and pumps can also be accomplished while the plant operates. However, those parts of the retrofit which involve tying into, re-routing, strengthening or otherwise modifying portions of the existing circulating water piping, the existing condenser and the existing intake/discharge structures will require that the plant be shut down and the existing cooling system be shut down and drained. This shutdown period, when the plant is unavailable for the generation of power, can represent a retrofit cost which, while not a capital cost but rather the loss of potential revenue, can be substantial. However, little information is available to this study from which to estimate, in any general way, a “typical” duration of plant downtime and an associated cost.

Two actual units retrofitted at a mid-sized coal fired plant in the Southeast experienced downtime of approximately two months per unit related to the tie-in of the new circulating water lines to and from the cooling tower to the existing condenser loop. In this situation, the access to the tie-in points, while confined and restricted, did not appear to be exceptionally so. To the extent that this represented a comparatively simple tie-in situation, it might constitute a lower bound on the time required for the final connection. However, for many plants the tie-ins might be accommodated during regularly scheduled outages or at least when there expected capcity factor is low. The general assumption, as discussed in Chapter 8, is that for fossil plants rated as “Easy” or “Average” retrofits, the cost of downtime will be assumed to be zero.

On the other hand, engineering estimates (not actual retrofit experiences) were made for the two large nuclear plants on the California coast and reported in the public literature (7-3). The downtime for San Onofre Nuclear Generating Station was reported to be just under 22 months with a lost of generation of over 33 million MWh and lost revenue of nearly $2.4 billion (7-15). The corresponding estimate for Diablo Canyon was 17 months with both units off-line and a loss of over 25 million MWH at a cost of approximately $1.8 billion (7-16).

The relationship between actual downtime and lost revenue can vary from one situation to another. For base-loaded plants essentially all the downtime represents a loss of generation and revenue. However plants with low capacity factors and peaking plants may have extended periods during the year when they do not operate. In principle, some retrofit activities could be scheduled for periods when the plant would not be expected to run. A plant-by-plant analysis of this situation is beyond the scope of this study but some general assumptions of the downtimes for different plant categories are used to estimate national costs as described in Chapter 8.

Re-optimization

The usual approach to a cooling system retrofit, as previously noted, is to install a cooling tower into an existing circulating water loop with no change to the circulating water flow rate or to the existing condenser. However, this approach may not be preferred in all circumstances. An important consideration in cooling system retrofits is whether the entire cooling system should be re-optimized to account for design selection differences between once-through and closed-cycle cooling. First, once-through systems are designed with higher cooling water flows and, hence, lower cooling water temperature rise than are closed-cycle systems. This is a result of the lower pump head requirements for once-through as opposed to the need to pump water to the top of a cooling tower in closed-cycle systems. Second, the condenser is often smaller with a higher terminal temperature difference (TTD) in once-through systems, particularly in situations where the reliable availability of cold water allows the maintenance of low condensing temperatures even at the higher condenser hot water exit temperatures. Third, for a given heat load, a cooling tower designed to cool a lower water flow over a greater cooling range will be smaller and less expensive and will consume less operating power than tower designed to cool a greater flow over a smaller range.

If, therefore, the retrofit consists simply of putting a cooling tower into the existing circulating water loop and retaining the existing condenser and cooling water flow rate, the system is far from optimum. The result is a low initial retrofit cost, but significantly higher penalty costs for the life of the plant. The usual result of a re-optimization is a reduction in the circulating water flow rate, often by as much as a factor of x2. This effectively halves the additional pumping power required and, by allowing the use of a smaller, more effective cooling tower, similarly reduces the number of fans and the associated fan power. These savings can represent over 0.5% of plant output over the remaining life of the plant.

However, the reduction in flow rate normally requires that the condenser be rebuilt, usually by changing it from a single-pass to a two-pass configuration in order to maintain the water velocity in the tubes at a high enough level to provide good heat transfer rates. For plants with low capacity factors and short remaining life, the simplest, least costly retrofit is likely to be the appropriate choice. For newer, baseload plants (including most nuclear facilities), which have an expected remaining life of at least 5 to 10 years, a full re-optimization may be the preferred approach.

However, as has been noted, the information upon which the retrofit cost estimates used in this study are based is, with but one exception, made up of cases where the usual approach was taken. Therefore, essentially no information is available upon which to base the range of costs which would be incurred for cases in which the system was re-optimized. While a study of the economic tradeoffs between the two approaches is beyond the scope of this study, it can be estimated that a full re-optimization would:

1. Put any retrofit project at a cost commensurate with the “Difficult” level. Condenser modifications can be expected to be particularly costly at most plants due to the crowded conditions surrounding the condenser and structural interferences from the turbine building walls. In addition, the change from a one-pass to a two-pass condenser would require waterbox modifications, relocation of the inlet or outlet piping to the opposite side of the turbine pedestal and possibly extensive changes to the structural foundations supporting the turbine.
2. A downtime of 6 months is assumed for all plants at which re-optimization is chosen as the preferred retrofit strategy.

Natural draft cooling towers

The choice of natural-draft towers, instead of mechanical draft towers, is rarely made in retrofit applications although a natural draft tower was recently chosen for a cooling system retrofit currently under construction at a plant in the Northeast. Natural draft towers were frequently the cooling system selected for new plant construction of larger nuclear and coal-fired plants in the U.S. in the 1970’s and 1980’s. There are over 100 natural draft towers currently in operation in the U.S. However, no new ones have been built for over 20 years until the most recent retrofit project in the Northeast. They normally are somewhat higher in capital cost but have significantly lower operating power requirements and reportedly lower maintenance costs. They also, because of limitations on air flow and fill height as a result of using buoyancy as the natural draft driving force, are designed for higher approach temperatures, typically 12 ºF to 18 ºF or higher compared to perhaps 6 ºF to 12 ºF for mechanical draft towers. For a given ambient condition this results in a higher turbine exhaust pressure as was discussed earlier in this section on energy penalty analysis. The combination of higher capital cost with lower operating cost can be the preferred solution for new plants with long expected life and high capacity factor. This was the case in the recent choice of natural draft towers for a new nuclear unit being planned in the Southeast. For the retrofit of existing units, if natural draft towers are chosen, it is normally for other reasons such as concern over ground level fogging as was the case for an existing retrofit project in the Northeast.

A single, well documented example for a large, base-loaded nuclear plant in the mid-Atlantic region reported a 5% higher capital costs with a 24% reduction in O&M costs and a reduction in energy/capacity penalty costs of about 30%. These costs, aggregated as a present value cost over a 13-year period from the start of retrofit construction, showed a 2.5% lower cost for the natural draft case. However, it should be noted that the long elapsed time since there has been any experience with the construction of natural draft towers in this country suggests a higher degree of uncertainty in cost estimates for natural draft tower installation. Also, the height and bulk of a large hyperbolic tower may create site-specific licensing problems in the form of aesthetic objections from neighboring populations.

Finally, the information from which the retrofit costs estimates in this study are derived comes entirely from studies and projects using mechanical draft towers. Therefore, no conclusions are drawn on the cost of using natural draft towers for closed-cycle wet cooling retrofits other than to note that it might be worthwhile to conduct an economic evaluation of natural draft towers as an alternative to mechanical draft in analyzing a cooling system retrofit at large, base-load plants with long remaining life.

Dry cooling

Some discussions of cooling system retrofits address the use of dry cooling as an alternative to closed-cycle wet cooling as a possible retrofit option. Dry cooling systems are of two types. The more common is direct dry cooling in which turbine exhaust steam is condensed in an air-cooled condenser. The other is indirect dry cooling in which the steam is condensed in a water-cooled, shell-and-tube condenser, as in once-through and closed-cycle wet cooling systems, and the hot condenser exit water is cooled in an air-cooled heat exchanger and then recirculated to the steam condenser. Direct dry cooling has seen increased acceptance as the cooling system of choice on some new power plants in the U.S. in recent years. No indirect all-dry cooling systems exist on U.S. power plants at this time.

Dry cooling of either type was not considered in this study for several reasons. First, given that closed-cycle wet cooling typically reduces the water withdrawn for cooling by 93 to 98 % of that required for once-through cooling, the use of dry cooling would represent only a small incremental further reduction in water intake rates. However, dry systems, in essentially all situations, are far more costly, require significantly more operating power and impose significantly higher efficiency/capacity penalties on the plants than is the case for wet systems. An engineering study of a California coastal plant (7-4) showed a doubling of the capital cost and a tripling of the operating/energy penalty costs for dry cooling in comparison to wet cooling. In addition, the physical size of air-cooled equipment occupies four to six times the land area and is two to three times higher than a corresponding mechanical-draft, wet cooling tower exacerbating the siting problem at existing plant sites.

Finally, the output limitation on hot days, which are normally coincident with days of highest demand for power, would be unacceptable with turbines originally designed for use with once-through cooling with a typical backpressure limitation of 5 in Hga. The use of dry cooling for retrofit in many situations would require turbine replacement with turbines capable of operation at higher backpressure as are used on new plants designed for dry cooling. The additional cost and the duration of plant downtime for such an extensive re-optimization and retrofit are unknown but would clearly significantly exceed the costs and duration of the more usual retrofit. The disadvantages are particularly significant for nuclear plants which suffer higher penalties with increased turbine exhaust pressure and are typically base-loaded.

The conclusion to exclude dry cooling from further consideration and discussion for plant cooling system retrofit is consistent with those of other studies of the subject including the TetraTech study (7-3) for the California Ocean Protection Council and the work of EPA in the development of the original Phase II rule (7-5).

Environmental and permitting issues

The emphasis in the bulk of this study has been on describing a methodology for making reasonable estimates of the capital, operating and maintenance costs involved in closed-cycle cooling retrofits with particular attention to those site-specific issues which might cause such retrofits at individual sites to be particularly costly. However, in addition to the financial costs described above, there are environmental and social impact considerations that also affected cost. The first is the environmental and social impact cost associated with the technology itself. These are similar to the cost of impingement and entrainment losses in that some but not all of these costs can be monetized. These impacts are discussed in a separate report (see companion EPRI 2010 report). The second is the cost of necessary permits and licenses necessary to construct closed-cycle cooling systems. No estimate is provided on the national cost for closed-cycle cooling permits and licenses but some companies have reports this cost can be hundreds of thousands of dollars. A third affect of the environmental and social impacts is that in some instances it may not be possible to obtain necessary permits and licenses due to site specific issues that would preclude a closed-cycle cooling retrofit. No estimate is provided of the number of facilities where this may be an issue. A short summary of some of the major environmental and social impact issues is provided below.

Increased air emissions

The primary air emissions from fossil plants are from the combustion of the fuel. As has been noted, the choice of cooling system can reduce the overall plant efficiency and capacity. Therefore, to meet a given total system load, more fuel must be burned with a corresponding increase in emissions of NO_x, particulate matter, SO_2 and CO_2 in amounts and proportions which depend on where and in what equipment the additional fuel is used.

Drift

Drift rates from modern, well designed cooling towers can be held to quite low levels. New installations have been quoted at less than 0.0005% of the circulating water flow rate. However, even that low rate will result in a total drift of nearly 2000 gallons per day from a 500 MW steam plant circulating 250,000 gpm. The environmental issues normally raised in connection with cooling tower drift are PM10 emissions, bacterial or pathogenic emissions and damage to local crops.

A very thorough discussion of the technical and regulatory aspects of all emissions from cooling towers including PM10 and PM2.5 are given by Micheletti (7-7), Riesman and Frisbie (7-8) and the California Energy Commission (7-9).

Visible plumes

On cold days, wet towers can produce a large visible plume as the warm saturated air leaving the tower mixes with the cold ambient air and water vapor condenses. In some locations, these plumes may obscure visibility, creating dangerous conditions on roadways or, along with drift, lead to local icing on neighboring roads or structures. In at least one instance, the Streeter plant in Cedar Falls, Iowa, a retrofit of a dry cooling tower was performed in order to eliminate plume effects on a nearby highway. Similar concerns led to the selection of a natural-draft wet tower for the retrofit at a Northeastern facility.

If a visible plume is deemed unacceptable, a cooling tower can be designed with plume abatement capability. This is accomplished by adding an air-cooled section to the tower and mixing the heated air off the dry section with the saturated air off the wet section to decrease the relative humidity of the mixed plume. Further mixing with the colder ambient air can then avoid the super-saturation zone where water vapor condensation and plume visibility would occur. A detailed discussion of the principles governing visible plume formation and the design options for plume abatement towers is given in Lindahl and Jameson (7-10).

The costs of plume abatement towers, both capital and operating costs, increase as the number of allowable hours of plume formation decrease. Estimates by Mirsky (7-11) used by EPA in their 316 (b) Development Document (7-5) suggest that a 32 ºF dry bulb limit on plume formation can increase the cost of the tower relative to a normal wet cooling tower by factors of x 2.5 to x 3.0 for the capital cost and x 1.25 to 1.5 for the operating cost.

Wastewater and solid waste

Potential issues regarding the return of cooling tower blowdown to local receiving waters will require careful, site-specific attention. Cooling towers using seawater for make-up would presumably blowdown back to the ocean, bay or estuary.

Noise

Cooling tower operation is noisier than once-through cooling operation. The primary noise from cooling towers is a combination of fan noise and "fill" noise caused by the flow of water down over the tower fill. Two limits must be considered. The first applies to worker safety and is set by OSHA. Cooling towers typically have no problem meeting these limits. The second is set by local or state ordinance either at the plant boundary or at some point in a neighboring area, such as the nearest receptor. This limit can vary from none to strict depending on the local situation. If strict limits apply, fan noise can be reduced through the choice of low noise fans, the water noise is less amenable to reduction and some sort of sound barrier may be required to comply with local ordinances.

Aesthetics

In some cases, where plants may be sited in a scenic or urban area, cooling towers may be deemed as a significant impact on the aesthetics of the locality. In many of the sites of interest to this study, this can be a very important consideration. For example, the scenic beauty of coastal areas from the beaches or from scenic drives on highways paralleling the shore is a treasured resource. The preservation of this resource is specifically protected in many venues and the issue is frequently addressed in siting hearings.

Water consumption

While once-through systems, as noted above, withdraw large quantities of water, they return all of the withdrawn water back to the source (or at least to nearby natural waterbodies). A recirculated cooling system, while withdrawing far less water, is designed to cool by evaporating a portion of the circulating water flow in order to cool the remainder. A typical evaporation rate for mechanical draft cooling towers is 10 gpm/MW representing 50 to 80% of the intake flow, again depending on the cycles of concentration. This loss of water to the source waterbody will exceed losses associated with increased evaporation rate from the receiving waters of a once-through cooling system. In some situations on some fresh waterbodies such as small rivers or lakes, this can be an important consideration.

Construction related effects

The site preparation and digging required for the installation of a cooling tower basin and new circulating water lines will involve the disturbing and disposal of potentially large amount of soil. In some situations, the soil on the plant site may be contaminated with oil or other organic substances from prior use. While this presents no problem if left undisturbed, it could present a significant permitting and financial burden for retrofit operations. The associated cost is impossible to generalize and would need to be developed on a site-specific basis.

Vegetation and wildlife

As a result of either the direct cooling tower footprint or drift cooling towers have the potential to impact terrestrial vegetation and wildlife on s site specific basis. This includes the potential to affect threatened and endangered species and/or protected habitat.

References-- Chapter 7

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8
NATIONAL COSTS

The national cost of retrofitting all the Phase II facilities listed in Appendix A is estimated by an extrapolation of the costs for plants for which information was available using

- the average cost factors for each "difficulty" category developed in Chapter 3
- an estimate of the number of plants falling into each degree of difficulty category based on the analyses of 125 specific plants as described in Chapters 4 and 5.

The details of how this extrapolation is performed and the resulting national costs are presented in the following sections.

Circulating water flows

Of the 428 Phase II facilities, 389 are fossil plants, 39 are nuclear plants. Plant capacities and circulating water flow rates are included on the list in Appendix A. All of the flow rate data were obtained from independent sources. In a few instances, when plant capacity data were not found, the capacities were estimated at 1 MW per million gallons per day of cooling water flow, corresponding very closely to the average of all the plants for which independent data were available.

The normalized cooling water flow in gpm/MW was calculated for each of the 428 facilities. The results for a few of the facilities appeared to be either unrealistically low (<200 gpm/MW) or unrealistically high (>1,200 gpm/MW). In an attempt to understand the possible effect of these plants on the overall results, the range of costs displayed above was first calculated using only those facilities for which the normalized cooling water flow lay between 200 and 1,200 gpm/MW. Those plants represented over 96% of the MW and cooling water flow, so the costs were scaled up by 4% and compared to the values obtained from the entire set of plants. The agreement was within 1%. Therefore, for purposes of extrapolation to national totals the data were used as listed.

The data are summarized in Table 8-1 for both fossil and nuclear facilities.

Table 8-1
Capacity and water flows at Phase II Facilities

Plant Type	No. of plants	Total capacity	Total circulating water flow
		MW	gpm
Fossil	389	252,000	139,507,000
Nuclear	39	60,000	42,789,000
Total	428	312,000	182,296,000

Capital cost extrapolations

Table 8-2 presents the results of arbitrarily applying the cost estimating equations developed in Chapter 3 for the several degrees of difficult to the entire family of Phase II facilities.

Table 8-2
Possible range of national costs for all Phase II facilities.

Plant Type	Capacity	Circulating Water Flow	National Cost Ranges for Varying Degrees of Difficulty ($ millions)					
			Nuclear		Fossil			
	MW	GPM	All "Less Difficult"	All "More Difficult"	All "Easy"	All "Average"	All "Difficult"	All "More Difficult"
Nuclear	60,000	42,789,000	$11,720	$27,560				
Fossil	252,000	139,507,000			$25,250	$38,360	$56,500	$79,520
All Plants	312,000	182,296,000	Minimum	Mid-range	Maximum			
			$36,970	$58,000	$107,080			

This is not to suggest that this is a plausible range of possible costs but rather to suggest that:

1. Even if <u>all</u> the retrofits were "Easy" (or "Less Difficult in the case of nuclear plants) representing the lowest cost projects from among the available plant specific information, the national cost would still approach $27 billion.

2. The high end cost of nearly $110 billion will be seen to significantly exceed the estimated cost resulting from this study's analysis. This comparison is intended to indicate that the results of the study are based on the thoughtful consideration of all factors influencing retrofit costs and not simply the assembly and extrapolation of high cost cases to produce an inflated national total.

The estimate of the national total is approached by considering the distribution across the degrees of difficulty of the 125 plants subjected to site-specific analysis and assuming that it constitutes a representative distribution of the complete family of Phase II plants. Plants representing approximately 22% of the fossil capacity were judged to be "Easy", 10% intermediate between "Easy" and "Average", 26% to be "Average", 13% between "Average" and "Difficult", 24% to be "Difficult" and 5% to be "More difficult". For the nuclear plants, approximately 30% of the capacity was "Less Difficult" and 30% "More Difficult" with the remaining 40% judged to be intermediate. In the case of nuclear plants, the sample size was very small, but the range of independent cost estimates as displayed in Figure 3-15 supports such an allocation. Applying this distribution to the complete set of Phase II facilities results in the costs displayed in Table 8-3.

Table 8-3
National retrofit costs with estimated degree of difficulty allocation[5]

Plant Type	Degree of Difficulty	Allocation	Capacity	Flow	Cost
		%	MW	gpm	$ millions
Fossil	Easy	22.0%	55,440	30,691,540	$5,560
	Easy to Average	10.0%	25,200	13,950,700	$3,180
	Average	26.0%	65,520	36,271,820	$9,970
	Average to Difficult	13.0%	32,760	18,135,910	$6,170
	Difficult	24.0%	60,480	33,481,680	$13,560
	More Difficult	5.0%	12,600	6,975,350	$3,980
Total fossil		100.0%	252,000	139,507,000	$42,410
Nuclear	Less Difficult	30.0%	15,000	10,697,000	$3,520
	More Difficult	30.0%	15,000	10,697,000	$8,270
	Intermediate	40.0%	30,000	21,394,000	$7,860
Total nuclear		100.0%	60,000	42,789,000	$19,640
Total Phase II			312,000	182,296,000	$62,050

This results in a cost of $42.2 billion for the fossil plants, $19.6 billion for the nuclear plants and a total for the family of Phase II facilities of approximately $62.1 billion or approximately 6% above the mid-range estimate in Table 8-2.

While a number of other extrapolation procedures might be considered such as applying the same allocation of degree of difficulty to the Phase II family as was found for the plants analyzed by region, or water type or type of surroundings, the variation around this more simple allocation is within +/-10% in all cases. Given that the level of accuracy of the estimating methodology for individual plants is no better that +/-20%, any attempt to select a preferred national total from among the various approaches to extrapolation would have a very limited confidence level. Therefore, a range of capital costs of +/-10% (See discussion in Chapter 6) around the total given in Table 8-3 or from $56 billion to $68 billion is the best estimate that can be provided at this time.

However, since EPA considered a breakdown of facilities according to source water type, a division of the total costs among the source water types of rivers, lakes and reservoirs, Great Lakes and "oceans, estuaries and tidal rivers" is shown in Table 8-4.. Each of these categories contains a large enough sample of plants that the allocation of degrees of difficulty developed for the total Phase II family of plants will be applied unchanged to each of the source water type categories.

[5] Some totals in this and future tables may not check exactly due to rounding.

Table 8-4
National costs for each water source type

Source Type	Circulating Water Flow, GPM			Capital Costs, $ millions		
	Nuclear	Fossil	All	Nuclear	Fossil	Total
Great Lakes	3,840,000	14,242,000	18,083,000	$1,760	$4,330	$6,090
Lakes and reservoirs	13,990,000	32,831,000	46,820,000	$6,420	$9,980	$16,400
Oceans/Estuaries/ Tidal Rivers	17,615,000	41,923,000	59,538,000	$8,090	$12,750	$20,840
Rivers	7,344,000	50,511,000	57,855,000	$3,370	$15,360	$18,730
Total	42,789,000	139,507,000	182,296,000	$19,640	$42,420	$62,060

Some capital cost adjustments

The national totals summarized in Tables 8-3 and 8-4 are based on the assumption that the entire family of eligible Phase II facilities will retrofit to closed-cycle cooling. However, there are additional considerations that can modify that assumption.

First, there are some facilities for which the installation of cooling towers is simply infeasible due primarily to lack of space on the site. The examination of 125 sites identified seven such sites, which were described in Chapter 5. On this basis, an adjustment to the calculation of the national cost was made assuming that 5% of the fossil facilities would be judged infeasible to retrofit and hence would not incur any cost. The adjustment was made by allocating this 5% among the four degrees of difficulty developed for fossil plants. No nuclear facilities were found to be infeasible so no adjustment was made in the nuclear retrofit cost estimates.

Second, a separate EPRI study (8-1), using the cost estimating methodology from this study, estimated that a number of fossil plants, given their recent capacity factors and remaining life, would choose to retire rather than retrofit. These assumed fossil retirements accounted for 26,058 MW. The degree of difficulty of the individual plants assumed to retire was not known in most cases since they were not plants for which site specific characteristics had been provided. However, the location and source water for each plant was known. Therefore, the reduction in the total number of MW subject to retrofit was allocated proportionally across both the degree of difficulty categories, but the individual reductions were assigned to the appropriate source water categories. No nuclear facilities were assumed to retire.

The two adjustments are evaluated separately. Table 8-5 lists the new distribution of plant capacity among the degrees of difficulty as adjusted for the 5% infeasible designation. Table 8-6 lists the distribution of these adjusted costs across the different source water categories.

Table 8-7 shows the adjusted national costs of retrofit when the retired sites are accounted for using the original percent allocations across the degrees of difficulty and Table 8-8 lists the corresponding costs by source water category.

Table 8-5
Adjustment of degree of difficulty allocations

Plant Type	Degree of Difficulty	Original Allocation	Revised Allocation (5% infeasible)	Revised Allocation of Capacity
		%	%	MW
Nuclear	Less Difficult	30.0%	30.0%	17,980
	More Difficult	30.0%	30.0%	17,980
	Intermediate	40.0%	40.0%	23,980
	Total	100.0%	100.0%	59,930
Fossil	Easy	22.0%	20.9%	52,670
	Easy to Ave	10.0%	9.5%	23,940
	Average	26.0%	24.7%	62,240
	Ave to Difficult	13.0%	12.4%	31,120
	Difficult	24.0%	22.8%	57,460
	More Difficult	5.0%	4.8%	11,970
	Infeasible	0.0%	5.0%	12,600
	Total	100.0%	100.0%	252,000
All plants	Total			312,320

Table 8-6
National capital cost adjusted for infeasible sites

Plant Type	Degree of Difficulty	Revised Allocation	Revised Allocation of Flow	Capital Cost
		%	GPM	$ millions
Nuclear	Less Difficult	30.0%	12,836,400	3,520
	More Difficult	30.0%	12,836,400	8,270
	Intermediate	40.0%	25,672,800	11,780
	Total	100.0%	42,789,000	$19,640
Fossil	Easy	20.9%	29,157,000	5,280
	Easy to Ave	9.5%	13,253,000	3,020
	Average	24.7%	34,458,000	9,480
	Ave to Difficult	12.4%	17,229,000	5,860
	Difficult	22.8%	31,808,000	12,880
	More Difficult	4.8%	6,627,000	3,780
	Infeasible	5.0%	6,975,000	0
	Total	100.0%	139,507,000	$40,300
All plants	Total		182,296,000	$59,940

Table 8-7
National capital cost by source water category (adjusted for infeasible sites)

Source Type	GPM			Capital Costs, $ millions		
	Nuclear	Fossil	All	Nuclear	Fossil	Total
Great Lakes	3,840,000	14,242,000	18,082,000	$1,760	$4,130	$5,890
Lakes and reservoirs	13,990,000	32,831,000	46,821,000	$6,420	$9,520	$15,940
Oceans/Estuaries/ Tidal Rivers	17,615,000	41,923,000	59,538,000	$8,090	$12,160	$20,250
Rivers	7,344,000	50,511,000	57,855,000	$3,370	$14,650	$18,020
Total	42,789,000	139,507,000	182,296,000	$19,640	$40,450	$60,090

Table 8-8 lists the capacity, flow and capital cots for the Phase II plants with the prematurely retired plants, making up an estimated 26,058 MW of retired fossil capacity, by degree of difficulty using the original allocation scheme with no allowance for infeasible plants. Table 8-9 shows the same information distributed across the four source water categories.

Table 8-8
National capital cost adjusted for premature retirements

Plant Type	Degree of Difficulty	Original Allocation	Capacity Adjusted for Retirements	Flow Adjusted for Retirements	Capital Cost
		%	MW	GPM	$ millions
Nuclear	Less Difficult	30.0%	18,000	12,836,400	$3,520
	More Difficult	30.0%	18,000	12,836,400	$8,270
	Intermediate	40.0%	24,000	17,115,200	$7,860
	Total	100.0%	60,000	42,789,000	$19,640
Fossil	Easy	22.0%	49,720	27,522,880	4,980
	Easy to Average	10.0%	22,600	12,510,400	2,850
	Average	26.0%	58,760	32,527,040	8,940
	Average to Difficult	13.0%	29,380	16,263,520	5,530
	Difficult	24.0%	54,240	30,024,960	12,160
	More Difficult	5.0%	11,300	6,255,200	3,570
	Infeasible	0.0%	0	0	0
	Total	100.0%	226,000	125,104,000	38,030
All plants	Total		286,000	167,893,000	$57,670

Table 8-9
National capital cost by source water category (adjusted for premature retirements)

Source Type	GPM			Capital Costs, $ millions		
	Nuclear	Fossil	All	Nuclear	Fossil	Total
Great Lakes	3,840,000	12,772,000	16,612,000	$1,760	$3,880	$5,640
Lakes and reservoirs	13,990,000	29,441,000	43,431,000	$6,420	$8,950	$15,370
Oceans/Estuaries/ Tidal Rivers	17,615,000	37,595,000	55,210,000	$8,090	$11,430	$19,520
Rivers	7,344,000	45,296,000	52,640,000	$3,370	$13,770	$17,140
Total	42,789,000	125,104,000	167,893,000	$19,640	$38,030	$57,670

A further adjustment can be made to account for the fact that California coastal plants are being required to retrofit to closed-cycle cooling (8-2) independent of the outcome of the EPA rulemaking. Therefore, results are provided excluding the cost of retrofitting California coastal plants from the national cost estimate resulting from the §316(b) rulemaking. The eventual resolution of the issue for the two large nuclear plants on the California coast is still uncertain, so the adjustment is made only for the fossil coastal plants. Table 8-10 shows the national cost totals with the California coastal fossil plants subtracted from the family of Phase II facilities and with the original allocation among degrees of difficulty used for the remaining plants. It should be noted that California has proposed an amendment to the Policy that would provide an exemption for repowered units. Units at three facilities would be exempted if the amendment were passed. Table 8-11 lists the new totals across the source water categories with all of the capacity being subtracted from the O/E/TR category which includes all coastal sites. This waterbody type is provided since that was an option considered by EPA for closed-cycle cooling in the prior Phase II Rule.

Table 8-10
National capital cost adjusted for subtraction of California coastal fossil plants

Plant Type	Degree of Difficulty	Original Allocation	Capacity adjusted for subtraction of California plants	Flow adjusted for subtraction of California plants	Capital Cost
		%	MW	GPM	$ millions
Nuclear	Less Difficult	30.0%	18,000	12,836,400	3,520
	More Difficult	30.0%	18,000	12,836,400	8,270
	Intermediate	40.0%	24,000	17,115,000	7,860
	Total	100.0%	60,000	42,787,800	19,650
Fossil	Easy	22.0%	52,270	29,222,200	$5,290
	Easy to Ave	10.0%	23,760	13,282,800	$3,030
	Average	26.0%	61,770	34,535,300	$9,500
	Ave to Difficult	13.0%	30,890	17,267,600	$5,870
	Difficult	24.0%	57,020	31,878,700	$12,910
	More Difficult	5.0%	11,880	6,641,400	$3,790
	Infeasible	0.0%	0	0	$0
	Total	100.0%	237,580	132,828,000	$40,390
All plants	Total		297,580	175,615,800	$60,040

Table 8-11
National capital costs by source water after subtraction of California coastal fossil plants (from the O/E/TR category)

Source Type	GPM			Capital Costs, $ millions		
	Nuclear	Fossil	All	Nuclear	Fossil	Total
Great Lakes	3,840,000	14,242,000	18,083,000	$1,760	$4,330	$6,090
Lakes and reservoirs	13,990,000	32,831,000	46,820,000	$6,420	$9,980	$16,400
Oceans/Estuaries/ Tidal Rivers	17,615,000	35,244,000	52,859,000	$8,090	$10,720	$18,810
Rivers	7,344,000	50,511,000	57,855,000	$3,370	$15,360	$18,730
Total	42,789,000	132,828,000	175,617,000	$19,640	$40,380	$60,020

Finally, Tables 8-12 and 8-13 show the same information for the combined subtractions and allocation adjustments. Both prematurely retired plants and California coastal fossil plants have been removed from the family of Phase II plants. The remaining plants have been allocated across the degrees of difficulty including a 5% allowance for sites infeasible to retrofit.

Table 8-12
National capital costs adjusted for subtraction of premature retirements and California coastal fossil plants with 5% assumed infeasible

Plant Type	Degree of Difficulty	Adjsuted Allocation	Capacity	Flow	Capital Cost
			MW	GPM	$ millions
Nuclear	Less Difficult	30.0%	17,979	12,836,667	$3,517
	More Difficult	30.0%	17,979	12,836,667	$8,267
	Intermediate	40.0%	23,972	17,115,556	$7,856
	Total	100.0%	59,931	42,788,889	$19,640
Fossil	Easy	20.9%	44,207	24,750,721	$4,480
	Easy to Average	9.5%	20,094	11,250,328	$2,565
	Average	24.7%	52,245	29,250,852	$8,044
	Average to Difficult	12.4%	26,123	14,625,426	$4,973
	Difficult	22.8%	48,226	27,000,786	$10,935
	More Difficult	4.8%	10,047	5,625,164	$3,206
	Infeasible	5.0%	10,576	5,921,225	$0
	Total	100.0%	211,519	118,424,501	$34,203
All plants	Total		271,450	161,213,389	$53,843

Table 8-13
Adjusted national capital costs by waterbody type

Plant Type	Source Water	Capacity	Water Flow	Capital
		MW	GPM	$ millions
Nuclear	Great Lakes	6,177	3,840,278	$1,760
	Lakes/Reservoirs	19,917	13,989,583	$6,420
	Oceans/Estuaries/Tidal Rivers	22,040	17,615,278	$8,090
	Rivers	11,797	7,343,750	$3,370
	Total Nuclear	59,931	42,788,889	$19,640
Fossil	Great Lakes	24,081	12,771,921	$3,700
	Lakes/Reservoirs	55,124	29,440,992	$8,540
	Oceans/Estuaries/Tidal Rivers	47,976	30,915,454	$8,960
	Rivers	84,338	45,296,134	$13,130
	Total Fossil	211,518	118,424,501	$34,340
All plants	Total Phase II	271,449	161,213,389	$53,980

Other costs

The costs tabulated above in Tables 8-2 through 8-13 include the capital costs of retrofit only. However, there are other costs which would result from retrofitting all the Phase II facilities with closed-cycle cooling, and they are significant. These include:

- cost of energy replacement incurred during plant outages during the retrofit activity
- cost of increased operating power requirements from closed-cycle operation
- cost of increased maintenance (eg., labor and chemicals) of closed-cycle cooling systems
- cost of energy replacement or increased fuel use resulting from reductions in plant efficiency and capacity from closed-cycle cooling performance limitations
- cost to finance the capital project
- any related permitting costs
- cost of electric system upgrades necessary due to unit retirement, energy replacement and efficiency loss
- cost of social and environmental impacts resulting from closed-cycle cooling.

Energy replacement during outage

As discussed in Section 7, the process of retrofitting an existing once-through cooled unit to closed-cycle cooling will require that the unit be off-line for an extended period. During this time, the energy which the unit would have generated must be replaced from other sources. A detailed estimate of the required downtime, the associated replacement energy and its cost for the 125 plants for which site-specific analyses were done is beyond the scope of this study. Therefore, the following paragraphs outline an approach to developing a generalized estimate of this cost element on a national basis.

Outage duration

In many cases, the cooling tower itself and much of the circulating water piping, pumps, sumps, valves and provisions for system make-up and blowdown can be constructed and installed while the plant continues to operate on the existing once-through cooling system. However, the plant must be off-line during periods when the cooling water flow to the steam condenser is interrupted or, when critical elements of the plant infrastructure must be disabled or relocated to make room for the tower or other elements.

Some plant outage will always be required for the tying-in of the new circulating water system to the existing condenser's intake/discharge piping. However, in most cases the tie-in can be accomplished during a scheduled outage. More extended downtime is required if structural reinforcement of the condenser or existing water tunnels is needed to withstand increased circulating water pressure. If significant condenser modifications such as are required for system re-optimization as was discussed in Section 7, the outage can be quite long. It was noted that re-optimization is most likely required for baseload plants with long remaining life. With this in mind, expected downtimes were assigned to different groupings of the family of Phase II facilities as follows:

1. Nuclear plants---For nuclear facilities, an average outage duration of 6 months is assumed. The basis for this assumption is that all nuclear plants are base-loaded and have a sufficiently long remaining life (say, at least 5 to 10 years) to justify re-optimization. Support for this assumption comes from recent studies (8-3, 8-4, 8-5, 8-6) of cooling system retrofits at nuclear plants by experienced engineering firms. The several studies estimated outage times ranging from 4 to 22 months.
2. Fossil plants--- Of the 389 fossil facilities, 307 provided unit specific capacity utilization data for a 5 year period. A review of the unit specific capacity data determined that approximately 30% of the generation for all 307 facilities was base-loaded with capacity factors of 75% or more. Assuming the 30% base-loaded capacity utilization data is representative of all 389 fossil facilities (252,392 MW) there is a total of 75,875 MW of base-loaded fossil generation.
   a. Assume that one-half of the base-loaded facilities (37,938 MW) have a long enough remaining life to justify re-optimization requiring a 6 month downtime.
   b. For the other half of the base-loaded facilities, it will be assumed that the percentage of MW rated as "Easy" or "Average" retrofits will be able to complete the retrofits during scheduled outage periods with no downtime penalty. The "Difficult" sites will be assumed to require 4 months downtime; the "More Difficult" case, 6 months;

Valuation of costs

The cost of the downtime is estimated in two steps:

1. Replacement energy required is estimated by multiplying the plant capacity (MW) by the assumed outage duration (hours) times the average capacity factors. The capacity factor estimates are based on data from the U. S. Energy Information Administration (8-7). The results for the full U. S. fleet on nuclear and fossil plants are shown in Table 8-14. Although the average age of the Phase II plants is likely somewhat older that the U. S. average, no information is available to make that adjustment, and the national capacity factors are applied to the Phase II plants for purposes of this estimate.
2. The cost per MWh of replacement energy can be valued as "lost revenue" to the particular plant or at the differential generation cost between the particular plant and other plants on the system which presumably have higher generation costs. Either of these costs can vary significantly throughout the year and from site to site and from system to system. A detailed analysis of these costs is beyond the scope of this study. A single value for the cost of replacement energy has, therefore, been set at $35/MWh for this estimate. The amount of replacement energy required and the cost to provide it for the nuclear plants and for the three groupings of fossil plants is shown in Table 8-15.

Table 8-14
Estimate of national capacity factors.

Plant Type	National Capacity	Annual Generation	Average Capacity Factor
	MW	MWh	%
Coal	315,500	2.02E+09	73.0%
Oil	61,500	6.57E+07	12.2%
Gas	427,700	8.97E+08	23.9%
Total Fossil	804,700	2.98E+09	42.3%
Nuclear	102,500	8.06E+08	89.8%

Table 8-15
Estimate of energy replacement costs.

Plant Type	Capacity of Phase II Units	Average Capacity Factor	Outage Duration	Annual Generation	Downtime Cost (@ $35/MWh)
	MW	%	Months	GWh	MM$
Nuclear	60,000	90%	6	236,000	$8,270
Fossil	0			0	$0
Baseloaded fossil plants	76,000			0	$0
Baseload/Long life	38,000	90%	6	150,000	$5,230
Remaining-Easy_Average	134,000	42%	0	0	$0
Remaining-Difficult	65,000	42%	4	80,000	$2,810
Remaining-More difficult	15,000	42%	6	28,000	$970
Total Fossil	252,000			257,000	$9,010
Total Phase II	312,000			494,000	$17,280

Operating power costs

An estimate of the additional operating costs for cooling tower fans and pumps required for closed-cycle cooling systems was discussed in Section 7. A gross estimate of the annual cost of increased O&M can be approximated as follows. The sum of the additional required operating power for the additional pumping head and the cooling tower fans was estimated to range from 0.9 to 1.7% of plant output. For fossil plants, the mid-range value of 1.3% or 13 kW/MW will be used. For nuclear plants, with an average normalized circulating water flow approximately 30% higher (See Table 8-1) than for fossil plants, the high end of the range, 17 kW/MW, will be used.

For plants which re-optimize, the circulating water flow and the tower size will be essentially halved. Therefore, assuming that all nuclear plants will re-optimize, 8.5 kW/MW (one-half of the 17 kW/MW discussed in the previous paragraph) will be used. For the fossil plants characterized as “Baseload/Long life”, the additional power is estimated as 0.65 % (6.5 kW/MW) of plant output.

Two additional questions must be considered. First, the additional power is consumed only when the plant is operating so an average capacity factor must be determined. The values tabulated in Table 8.15 are used.

The second question, as was the case for the downtime costs, is how to value the additional power required. For plants operating at full load, the added operating power subtracts from the energy available to send out and should be evaluated as lost revenue or the differential generation cost. For plants operating at part load, the firing rate can be increased to achieve the same net output and the cost is that for the additional fuel burned. On the basis of lost revenue, a penalty of $40/MWh might be a reasonable average. At an average heat rate of 10,000 Btu/kWh or 10,000,000Btu/MWh and $3/million Btu, the penalty, evaluated at the increased fuel cost, is $30/MWh. For purposes of this estimate, an intermediate value of $35/MWh will be used. The results are displayed in Table 8-16.

Table 8-16
Estimate of annual cost of additional power requirements

Plant Type	Capacity	Add'l Power	Average Capacity Factor	Annual Energy Consumed	Annual Cost (@ $35/MWh)
	MW	MW	%	MWh	$ millions
Fossil, re-optimized	38,000	250	90.0%	1,971,000	$69
Fossil, standard	214,000	2,780	42.0%	10,228,000	$358
Total Fossil	252,000	3,030		12,199,000	$427
Nuclear	60,000	510	90.0%	4,021,000	$141
Total Phase II	312,000	3,540		16,220,000	$568

Energy penalty costs

A similar calculation can be made of the cost of the annual energy penalty resulting from the increased turbine backpressure and reduced turbine efficiency. Tables 7-3 and 7-4 list the differences in turbine backpressure at “hot day” (Table 7-3) and “annual average” (Table 7-4) conditions for example sites in seven geographical regions with differing climates and source waters. They show a wide range varying from -0.9 to 1.15 in Hga on hot days with an average of about 0.6 in Hga and from 0.55 to 1.41 in Hga with an average of about 0.9 in Hga at annual average conditions. As discussed in the sections accompanying these tables, the differences stem from differences in the source water temperature for once-through cooling and the wet bulb temperature plus the tower approach for closed-cycle cooling.

It may seem counter-intuitive, given the attention normally given to “hot day” limitations, that the backpressure differences are sometimes higher at annual average conditions than at hot day conditions. However, two points must be considered. First, the turbine performance curves are non-linear and a given increase in backpressure results in a higher output reduction at the higher backpressure levels encountered on hot days than at the lower levels encountered at annual average conditions. Second, hot day conditions are typically days of high system loads when individual plants are operating at full load and being asked to maximize output. This likely means that they are already operating at high backpressure, possible approaching the “alarm” or "trip" point. Therefore, any additional reductions in output due to cooling system limitations are particularly noteworthy. Additionally, the price per MWh on hot days for some plants can be significantly above the annual average price so any output penalty is particularly costly.

An estimate of the aggregated national cost of the energy/capacity penalties associated with cooling system retrofits can be developed in a manner similar to that used for the cost of the increased operating power requirements.

The average backpressure increase across the seven regions will be used for the hot day and annual average conditions. The output reduction per unit increase in turbine exhaust pressure, expressed as "% reduction per in Hga" is assumed to be 1%/in Hga at annual average conditions and 2%/in Hga at hot day conditions. "Hot day" conditions will be assumed to pertain for 10% of the year (876 hours) and annual average conditions for the remainder of the year (7,884 hours).

It is noted that in some situations, particularly in the southeast on small rivers or in the south central area on small ponds or lakes, the source water temperature in the summer can exceed the temperature of cold water available from a cooling tower. Therefore, there can be a net increase in hot day efficiency and output. These considerations were factored into the establishment of the average penalty in Chapter 7.

Finally, the values of the lost output could be evaluated as lost revenue at the appropriate price per MWh, as increased fuel cost if the reduction can be made up by increased firing, or at the differential production cost if the load is replaced by another plant presumably with somewhat higher production costs. A detailed analysis of this issue is beyond the scope of this effort, and, as above, the reduced output will be valued at $35/MWh. It is recognized that, in some situations, the value of hot day output may be significantly greater than this, but the information is not available to apply such considerations to the national cost estimates. Table 8-17 tabulates the results of the estimating procedure.

Table 8-17
Estimate of annual cost of heat rate energy penalty

Plant Type	Capacity	Increased Backpressure	Percent Output Reduction	Hours per year	Capacity Factor	Cost (@ $35/MWh)
	MW	in Hga	%	hr	%	$
Fossil						
Baseloaded	76,000					
Hot day		0.6	2.00%	876	90%	$42
Annual average		0.9	1.00%	7,884	90%	$189
Remaining	177,000					
Hot day		0.6	2.00%	876	84%	$91
Annual average		0.9	1.00%	7,884	42%	$205
Total fossil	253,000					$527
Nuclear	60,000					
Hot day		0.6	2.00%	876	90%	$33
Annual average		0.9	1.00%	7,884	90%	$149
Total nuclear	60,000					$182
Total all plants	313,000					$709

Summary and aggregation of costs

The four major cost elements considered in this report include:

- initial capital cost
- energy replacement during outage or "downtime" cost
- additional operating cost
- heat rate penalty cost.

These costs differ in that the first two cost elements (capital and downtime) are incurred once, at the beginning of the retrofit project. The latter two (operating and penalty) costs are annual costs and are incurred every year for the remaining life of the plant.

Two standard methods are used to put these costs on a common basis. These are an annualized cost basis and a net present value (NPV) basis.

An annualized cost is calculated as the sum of

- the initial (capital and downtime) costs time an amortization factor and
- one year's annual (operating and penalty) costs.

Using an amortization factor of 7%, the calculation is given by

$$\$_{annaulized} = (\$_{capital} + \$_{downtime}) \text{ x } .07 + (\$_{operating} + \$_{penalty})$$

The NPV cost is calculated by discounting the present value of annual costs which will not be incurred until future years by applying a discount factor. This discount factor is a function of the discount rate and the number of years in the future until the cost is incurred. The discounted costs for each future year of the remaining plant lifetime are aggregated into the discount factor as

$$\text{Discount factor} = \Sigma\ 1/(1 + r)^n \text{ from } n = 1 \text{ to } n = N \text{ (where N = remaining life)}$$

Numerically for $r = 7\%$ and $N = 30$,

$$\text{Discount factor} = 12.409$$

The NPV is then calculated as

$$NPV = (\$_{capital} + \$_{downtime}) + 12.409 \text{ x } (\$_{operating} + \$_{penalty})$$

The following five tables summarize the results of the study.

Table 8-18 lists the four individual cost elements, the annualized cost and the NPV for the complete family of nuclear and fossil Phase II facilities using the original allocation among the degrees of difficulty and distributed across the four waterbody types.

Table 8-19 lists the costs with the allocation of plants across the degrees of difficulty revised to account for 5% of the fossil plants deemed infeasible for retrofit.

Table 8-20 lists the national costs with premature retirements using the original allocation of plants across the degrees of difficulty.

Table 8-21 lists the national costs with the California fossil-fired coastal plants removed using the original allocation across the degrees of difficulty.

Table 8-22 aggregates all the above adjustments and lists the national retrofit capital costs for the family of Phase II plants with premature retirements and California coastal fossil plants subtracted and the revised allocation across the degrees of difficulty to account for 5% of the sites being deemed infeasible for retrofit.

Table 8-18
Summary of costs---All Phase II plants

Plant Type	Source Water	Capacity	Water Flow	Costs					
		Capacity	Water Flow	Capital	Operating Power	Heat Rate Penalty	Downtime	Annualized Cost	Net Present Value
		MW	GPM	$ millions	$ millions	$ millions	$ millions	$ millions	$ millions
Nuclear	Great Lakes	6,000	3,840,000	$1,760	$13	$16	$740	$200	$2,860
	Lakes/Reservoirs	20,000	13,990,000	$6,420	$46	$60	$2,700	$740	$10,430
	O/E/TR	22,000	17,615,000	$8,090	$58	$75	$3,400	$940	$13,140
	Rivers	12,000	7,344,000	$3,370	$24	$31	$1,420	$390	$5,480
	Total Nuclear	60,000	42,789,000	$19,640	$141	$182	$8,270	$2,280	$31,920
Fossil	Great Lakes	27,000	14,242,000	$4,330	$44	$54	$920	$480	$6,460
	Lakes/Reservoirs	61,000	32,831,000	$9,980	$100	$124	$2,120	$1,110	$14,890
	Oceans/Estuaries/ Tidal Rivers	70,000	41,923,000	$12,750	$128	$158	$2,710	$1,410	$19,010
	Rivers	94,000	50,511,000	$15,360	$155	$191	$3,260	$1,700	$22,910
	Total Fossil	252,000	139,507,000	$42,420	$427	$527	$9,010	$4,700	$63,270
All plants	Total Phase II	312,000	182,296,000	$62,060	$568	$709	$17,280	$6,970	$95,190

Table 8-19
Summary of costs---Adjusted for infeasible sites

Plant Type	Source Water	Capacity	Water Flow	Costs					
				Capital	Operating Power	Heat Rate Penalty	Downtime	Annualized Cost	Net Present Value
		MW	GPM	$ millions	$ millions	$ millions	$ millions	$ millions	$ millions
Nuclear	Great Lakes	6,177	3,840,278	$1,760	$13	$16	$742	$204	$2,862
	Lakes/Reservoirs	19,917	13,989,583	$6,420	$46	$60	$2,703	$744	$10,433
	O/E/TR	22,040	17,615,278	$8,090	$58	$75	$3,404	$937	$13,143
	Rivers	11,797	7,343,750	$3,370	$24	$31	$1,419	$391	$5,477
	Total Nuclear	59,931	42,788,889	$19,640	$141	$182	$8,269	$2,276	$31,915
Fossil	Great Lakes	26,853	14,242,361	$4,130	$41	$51	$874	$443	$6,150
	Lakes/Reservoirs	61,470	32,830,556	$9,520	$95	$118	$2,014	$1,020	$14,177
	O/E/TR	70,020	41,922,917	$12,160	$122	$150	$2,572	$1,303	$18,107
	Rivers	94,048	50,511,111	$14,650	$147	$181	$3,099	$1,570	$21,816
	Total Fossil	252,391	139,506,944	$40,460	$406	$500	$8,558	$4,336	$60,251
All plants	Total Phase II	312,322	182,295,833	$60,100	$546	$682	$16,827	$6,613	$92,166

Table 8-20
Summary of national costs with premature retirements removed using the original allocation across degrees of difficulty

Plant Type	Source Water	Capacity	Water Flow	Costs					
				Capital	Operating Power	Heat Rate Penalty	Downtime	Annualized Cost	Net Present Value
		MW	GPM	$ millions	$ millions	$ millions	$ millions	$ millions	$ millions
Nuclear	Great Lakes	6,177	3,840,278	$1,760	$13	$16	$742	$204	$2,862
	Lakes/Reservoirs	19,917	13,989,583	$6,420	$46	$60	$2,703	$744	$10,433
	O/E/TR	22,040	17,615,278	$8,090	$58	$75	$3,404	$937	$13,143
	Rivers	11,797	7,343,750	$3,370	$24	$31	$1,419	$391	$5,477
	Total Nuclear	59,931	42,788,889	$19,640	$141	$182	$8,269	$2,276	$31,915
Fossil	Great Lakes	24,081	12,771,921	$3,880	$39	$49	$873	$421	$5,849
	Lakes/Reservoirs	55,124	29,440,992	$8,950	$90	$113	$2,012	$971	$13,490
	O/E/TR	62,791	37,594,620	$11,430	$115	$145	$2,569	$1,240	$17,227
	Rivers	84,338	45,296,134	$13,770	$139	$175	$3,096	$1,494	$20,755
	Total Fossil	226,333	125,103,667	$38,030	$383	$482	$8,550	$4,126	$57,321
All plants	Total Phase II	286,264	167,892,556	$57,670	$524	$664	$16,818	$6,403	$89,236

Table 8-21
Summary of national costs with California plants removed using the original allocation across degrees of difficulty

Plant Type	Source Water	Capacity	Water Flow	Costs					
		Capacity	Water Flow	Capital	Operating Power	Heat Rate Penalty	Downtime	Annualized Cost	Net Present Value
		MW	GPM	$ millions	$ millions	$ millions	$ millions	$ millions	$ millions
Nuclear	Great Lakes	6,177	3,840,278	$1,760	$13	$16	$742	$204	$2,862
	Lakes/Reservoirs	19,917	13,989,583	$6,420	$46	$60	$2,703	$744	$10,433
	O/E/TR	22,040	17,615,278	$8,090	$58	$75	$3,404	$937	$13,143
	Rivers	11,797	7,343,750	$3,370	$24	$31	$1,419	$391	$5,477
	Total Nuclear	59,931	42,788,889	$19,640	$141	$182	$8,269	$2,276	$31,915
Fossil	Great Lakes	26,853	14,242,361	$4,330	$43	$54	$938	$466	$6,470
	Lakes/Reservoirs	61,470	32,830,556	$9,980	$99	$124	$2,162	$1,073	$14,912
	O/E/TR	55,205	35,243,750	$10,720	$107	$133	$2,321	$1,153	$16,015
	Rivers	94,048	50,511,111	$15,360	$153	$191	$3,327	$1,652	$22,949
	Total Fossil	237,576	132,827,778	$40,390	$402	$501	$8,748	$4,343	$60,346
All plants	Total Phase II	297,507	175,616,667	$60,030	$543	$683	$17,016	$6,619	$92,261

Table 8-22
Summary of national costs with aggregated adjustments accounted for

Plant Type	Source Water	Capacity	Water Flow	Costs					
		Capacity	Water Flow	Capital	Operating Power	Heat Rate Penalty	Downtime	Annualized Cost	Net Present Value
		MW	GPM	$ millions	$ millions	$ millions	$ millions	$ millions	$ millions
Nuclear	Great Lakes	6,177	3,840,278	$1,760	$13	$16	$742	$204	$2,862
	Lakes/Reservoirs	19,917	13,989,583	$6,420	$46	$60	$2,703	$744	$10,433
	O/E/TR	22,040	17,615,278	$8,090	$58	$75	$3,404	$937	$13,143
	Rivers	11,797	7,343,750	$3,370	$24	$31	$1,419	$391	$5,477
	Total Nuclear	59,931	42,788,889	$19,640	$141	$182	$8,269	$2,276	$31,915
Fossil	Great Lakes	24,081	12,771,921	$3,700	$39	$49	$882	$409	$5,674
	Lakes/Reservoirs	55,124	29,440,992	$8,540	$89	$114	$2,033	$943	$13,090
	O/E/TR	47,976	30,915,454	$8,960	$94	$119	$2,135	$990	$13,738
	Rivers	84,338	45,296,134	$13,130	$137	$175	$3,128	$1,450	$20,131
	Total Fossil	211,518	118,424,501	$34,330	$359	$457	$8,177	$3,792	$52,633
All plants	Total Phase II	271,449	161,213,389	$53,970	$499	$639	$16,446	$6,068	$84,548

Further considerations

Additional costs not included

A number of the cost elements listed earlier in the chapter were not included in the totals.

1. Additional maintenance costs are highly dependent on site source water quality and operating procedures at any individual plant. They are sometimes factored as 2 to 3% of equipment cost which in turn is 15 to 30% of the retrofit capital cost resulting in minimum additional costs of less than 1%.
2. Permitting costs, while potentially significant, are highly site-specific, and there is no obvious method for generalizing them.
3. The costs of financing the capital cost of the project were omitted by considering the retrofit to be an "overnight" project. Some discussion of the inclusion (or lack of it) of AFUDC in some of the independent cost studies was included in Chapter 6.
4. Two other costs, the cost of electrical system upgrades and the social/environmental costs were beyond the scope of this study and are addressed in companion EPRI studies identified in Chapter 1.

Effect of some assumptions

In the course of this analysis, some assumptions were made. While most of these were identified and discussed throughout the report, an additional few are identified here with a brief note as to their possible effect on the total national costs.

1. It is believed that all eligible Phase II facilities have been identified correctly. If any have been missed or included erroneously, the estimate could be slightly low or high
2. It has been assumed that the §316(b) rulemaking will apply to facilities that use more than 50 MGD. If this cutoff limit were to increase or decrease, the number of facilities affected and the national cost estimate would be correspondingly lower or higher.
3. All facilities will implement closed-cycle cooling with mechanical-draft cooling towers. Other options may alter the distribution of costs. For example, the use of natural-draft cooling towers would generally increase the capital costs and the heat rate penalty cost elements while reducing the operating power cost element.
4. The assumed number of plants choosing to re-optimize and the assumed downtime for plants which do re-optimize is uncertain and could affect the national totals in either direction.
5. Similarly, the adjustments made for plants assumed to be infeasible for retrofit and for plants choosing to retire rather than to retrofit are uncertain and could alter the totals up or down.
6. It is also possible that some sites may be unable to obtain the necessary permits to install cooling towers and would, therefore, not retrofit. No attempt was made to include estimates of how many such sites there may be with the results that the totals may be slightly high.
7. Some plants may experience increased efficiency and annual output as a result of a conversion to closed-cycle cooling. This may occur, for example, at plants where the

summertime output is occasionally curtailed due to discharge temperature limitations on the once-through cooling water discharge. There may also be occasional low flow conditions in the source water supply for once-through cooling that limits plant output. No attempt was made to quantify the frequency or magnitude of these effects and no information was available to the study to do so. This omission will result in some overestimate of the total national "heat rate penalty" costs.

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5. URS Corporation, "Determination of Cooling Tower Availability for Oyster Creek Generating Station", March, 2006.
6. Enercon Services, Inc., "Engineering Feasibility and Costs of Conversion of Indian Point Units 2 AND 3 to a Closed-Loop Condenser Cooling Water Configuration, February, 2010
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9
SUMMARY AND CONCLUSIONS

Summary

The study develops estimates of the national costs of retrofitting the family of Phase II facilities, which includes all existing plants on once-through cooling withdrawing more than 50 million gallons per day, to closed-cycle cooling. The results are intended to inform the EPA "Existing Facilities" rulemaking by providing clearly documented estimates of the costs that would be incurred as a result of such a requirement.

Methodology

The primary focus of the study is on the capital cost of the retrofits. The costs were derived from information of the actual and estimated costs of individual projects from a variety of sources for 82 power plants. The plants were separated into groups of nuclear and fossil (coal, oil and gas) plants. The costs for each were plotted against the cooling water flow rate for the existing once-through cooled system. The costs for each plant type, while generally linearly proportional to flow, exhibited considerable scatter at all flow rates. The individual plant costs were further grouped into low, intermediate and higher cost categories. These categories again exhibited linear behavior with flow and the scatter within each category was significantly reduced. These categories were assumed to correspond to retrofit projects of varying degrees of difficulty. The fossil cost data were divided into four groups (Easy, Average, Difficult, and More difficult); the nuclear date into two (Less difficult and More difficult) and a linear relationship of cost vs. circulating water flow rate was established for each of the six categories.

Site characteristics were identified which influenced the difficulty of retrofit at any particular site. Information on these site characteristics was obtained through an industry survey for 185 plants. Site specific evaluations were made and a judgment rendered on the likely degree of difficulty for 125 of these plants. For those sites judged to be intermediate between any two of the four dgrees of difficulty the average of the two bounding categories was used.

In addition, estimates were made of three other significant cost elements. There were the cost of energy replacement during the time a plant is down for retrofitting, the annual cost of additional operating power and the annual cost of the heat rate penalty resulting from thermal limitations of the closed-cycle cooling system.

Estimates of the downtime duration for nuclear and fossil plants were based on a limited number of independent engineering studies for nuclear plants and information from a few actual retrofits at fossil plants.

No plant-specific information on the operating and heat rate penalty cost were available. Therefore, generalized estimates based on well-established hydraulic and thermal performance characteristics of cooling systems and steam turbine performance curves were made and applied to the aggregate of plants.

The national cost totals were calculated for three sets of plants. These were

- the complete family of nuclear and fossil plants determined to be Phase II plants eligible for retrofit,
- the complete family modified by an adjustment for the number of plants assumed to be infeasible to retrofit or assumed to choose to retire rather than retrofit
- the adjusted family of plants with California coastal fossil plants excluded on the basis that they are already under direction to retrofit by the California Water Resources Control Board.

All three sets of costs were further allocated among four source water types: Great Lakes, Lakes and reservoirs, Oceans, Estuaries and Tidal Rivers (O/E/TR) and Rivers.

Finally the initial (capital and downtime) cost elements were combined with the annual (operating power and heat rate penalty) cost elements both as an annualized cost and as a net present value.

Results for national cost totals

The results are listed in Tables 8-18 through 8-22 and are reproduced here as Tables 9-1 through 9-5 for convenience of reference.

Table 9-1
Total national costs for complete family of Phase II plants

Plant Type	Source Water	Capacity	Water Flow	Costs: Capital	Costs: Operating Power	Costs: Heat Rate Penalty	Costs: Downtime	Annualized Cost	Net Present Value
		MW	GPM	$ millions	$ millions	$ millions	$ millions	$ millions	$ millions
Nuclear	Great Lakes	6,000	3,840,000	$1,760	$13	$16	$740	$200	$2,860
	Lakes/Reservoirs	20,000	13,990,000	$6,420	$46	$60	$2,700	$740	$10,430
	O/E/TR	22,000	17,615,000	$8,090	$58	$75	$3,400	$940	$13,140
	Rivers	12,000	7,344,000	$3,370	$24	$31	$1,420	$390	$5,480
	Total Nuclear	60,000	42,789,000	$19,640	$141	$182	$8,270	$2,280	$31,920
Fossil	Great Lakes	27,000	14,242,000	$4,330	$44	$54	$920	$480	$6,460
	Lakes/Reservoirs	61,000	32,831,000	$9,980	$100	$124	$2,120	$1,110	$14,890
	Oceans/Estuaries/ Tidal Rivers	70,000	41,923,000	$12,750	$128	$158	$2,710	$1,410	$19,010
	Rivers	94,000	50,511,000	$15,360	$155	$191	$3,260	$1,700	$22,910
	Total Fossil	252,000	139,507,000	$42,420	$427	$527	$9,010	$4,700	$63,270
All plants	Total Phase II	312,000	182,296,000	$62,060	$568	$709	$17,280	$6,970	$95,190

Table 9-2
Adjusted national cost totals accounting for 5% infeasible sites

Plant Type	Source Water	Capacity	Water Flow	Costs: Capital	Costs: Operating Power	Costs: Heat Rate Penalty	Costs: Downtime	Annualized Cost	Net Present Value
		MW	GPM	$ millions	$ millions	$ millions	$ millions	$ millions	$ millions
Nuclear	Great Lakes	6,177	3,840,278	$1,760	$13	$16	$742	$204	$2,862
	Lakes/Reservoirs	19,917	13,989,583	$6,420	$46	$60	$2,703	$744	$10,433
	O/E/TR	22,040	17,615,278	$8,090	$58	$75	$3,404	$937	$13,143
	Rivers	11,797	7,343,750	$3,370	$24	$31	$1,419	$391	$5,477
	Total Nuclear	59,931	42,788,889	$19,640	$141	$182	$8,269	$2,276	$31,915
Fossil	Great Lakes	26,853	14,242,361	$4,130	$41	$51	$874	$443	$6,150
	Lakes/Reservoirs	61,470	32,830,556	$9,520	$95	$118	$2,014	$1,020	$14,177
	O/E/TR	70,020	41,922,917	$12,160	$122	$150	$2,572	$1,303	$18,107
	Rivers	94,048	50,511,111	$14,650	$147	$181	$3,099	$1,570	$21,816
	Total Fossil	252,391	139,506,944	$40,460	$406	$500	$8,558	$4,336	$60,251
All plants	Total Phase II	312,322	182,295,833	$60,100	$546	$682	$16,827	$6,613	$92,166

Table 9-3
Adjusted national cost totals with premature retirements subtracted

Plant Type	Source Water	Capacity MW	Water Flow GPM	Costs: Capital $ millions	Costs: Operating Power $ millions	Costs: Heat Rate Penalty $ millions	Costs: Downtime $ millions	Costs: Annualized Cost $ millions	Costs: Net Present Value $ millions
Nuclear	Great Lakes	6,177	3,840,278	$1,760	$13	$16	$742	$204	$2,862
	Lakes/Reservoirs	19,917	13,989,583	$6,420	$46	$60	$2,703	$744	$10,433
	O/E/TR	22,040	17,615,278	$8,090	$58	$75	$3,404	$937	$13,143
	Rivers	11,797	7,343,750	$3,370	$24	$31	$1,419	$391	$5,477
	Total Nuclear	59,931	42,788,889	$19,640	$141	$182	$8,269	$2,276	$31,915
Fossil	Great Lakes	24,081	12,771,921	$3,880	$39	$49	$873	$421	$5,849
	Lakes/Reservoirs	55,124	29,440,992	$8,950	$90	$113	$2,012	$971	$13,490
	O/E/TR	62,791	37,594,620	$11,430	$115	$145	$2,569	$1,240	$17,227
	Rivers	84,338	45,296,134	$13,770	$139	$175	$3,096	$1,494	$20,755
	Total Fossil	226,333	125,103,667	$38,030	$383	$482	$8,550	$4,126	$57,321
All plants	Total Phase II	286,264	167,892,556	$57,670	$524	$664	$16,818	$6,403	$89,236

Table 9-4
Adjusted national cost totals with California coastal fossil plants subtracted

Plant Type	Source Water	Capacity MW	Water Flow GPM	Costs: Capital $ millions	Costs: Operating Power $ millions	Costs: Heat Rate Penalty $ millions	Costs: Downtime $ millions	Costs: Annualized Cost $ millions	Costs: Net Present Value $ millions
Nuclear	Great Lakes	6,177	3,840,278	$1,760	$13	$16	$742	$204	$2,862
	Lakes/Reservoirs	19,917	13,989,583	$6,420	$46	$60	$2,703	$744	$10,433
	O/E/TR	22,040	17,615,278	$8,090	$58	$75	$3,404	$937	$13,143
	Rivers	11,797	7,343,750	$3,370	$24	$31	$1,419	$391	$5,477
	Total Nuclear	59,931	42,788,889	$19,640	$141	$182	$8,269	$2,276	$31,915
Fossil	Great Lakes	26,853	14,242,361	$4,330	$43	$54	$938	$466	$6,470
	Lakes/Reservoirs	61,470	32,830,556	$9,980	$99	$124	$2,162	$1,073	$14,912
	O/E/TR	55,205	35,243,750	$10,720	$107	$133	$2,321	$1,153	$16,015
	Rivers	94,048	50,511,111	$15,360	$153	$191	$3,327	$1,652	$22,949
	Total Fossil	237,576	132,827,778	$40,390	$402	$501	$8,748	$4,343	$60,346
All plants	Total Phase II	297,507	175,616,667	$60,030	$543	$683	$17,016	$6,619	$92,261

Table 9-5
National cost totals with adjusted degree of difficulty allocations and retired and California coastal fossil plants excluded

Plant Type	Source Water	Capacity	Water Flow	Costs: Capital	Operating Power	Heat Rate Penalty	Downtime	Annualized Cost	Net Present Value
		MW	GPM	$ millions	$ millions	$ millions	$ millions	$ millions	$ millions
Nuclear	Great Lakes	6,177	3,840,278	$1,760	$13	$16	$742	$204	$2,862
	Lakes/Reservoirs	19,917	13,989,583	$6,420	$46	$60	$2,703	$744	$10,433
	O/E/TR	22,040	17,615,278	$8,090	$58	$75	$3,404	$937	$13,143
	Rivers	11,797	7,343,750	$3,370	$24	$31	$1,419	$391	$5,477
	Total Nuclear	59,931	42,788,889	$19,640	$141	$182	$8,269	$2,276	$31,915
Fossil	Great Lakes	24,081	12,771,921	$3,700	$39	$49	$882	$409	$5,674
	Lakes/Reservoirs	55,124	29,440,992	$8,540	$89	$114	$2,033	$943	$13,090
	O/E/TR	47,976	30,915,454	$8,960	$94	$119	$2,135	$990	$13,738
	Rivers	84,338	45,296,134	$13,130	$137	$175	$3,128	$1,450	$20,131
	Total Fossil	211,518	118,424,501	$34,330	$359	$457	$8,177	$3,792	$52,633
All plants	Total Phase II	271,449	161,213,389	$53,970	$499	$639	$16,446	$6,068	$84,548

The capital cost results were compared with independent information for 34 plants. The typical variation was +/- 20 to 25% with a few significantly higher. In aggregate, however, the agreement was within 10%. It was concluded on this basis that the methodology was reasonably reliable and contained no significant bias.

The total costs include, in addition to the initial capital costs, the costs of additional operating power, of efficiency and output penalty and of energy replacement during downtime. The total costs, however, may not reflect the complete cost because they do not include potentially substantial costs of permitting, additional labor and materials necessary for maintenance of closed-cycle systems, any necessary electrical system upgrades, any resultant social and environmental impacts and the cost of capital project financing.

Conclusions

The results of the analysis suggest a number of observations and conclusions.

- In general retrofitting existing once-through cooled plants with closed-cycle cooling using cooling towers is much more difficult and costly than installing closed-cycle cooling at a new, greenfield site. This can be due to a variety of factors including limited space availability, underground interferences to the installation of circulating water piping, the need to relocate existing equipment and structures and the need to modify and upgrade existing circulating water intake/discharge structures and tunnels.
- There is a wide range for the cost of a retrofit depending on site-specific factors. Independent data sources indicated capital retrofit costs for fossil plants ranging from $181/gpm to $570/gpm, a factor of 3.2; for nuclear plants the range was from $274/gpm to $644/gpm, a factor of 2.6.
- Nuclear plants are, on average, more costly to retrofit than fossil plants. Nuclear plants account for 19% of the capcity of the family of Phase II plants but over 30% of the national capital costs of retrofit.
- The combination of the additional operating power requirements and the reduced plant efficiency are estimated to effectively reduce the available capacity of the family of Phase II plants by just over 3% or almost 10,000 MW.
- Additional capacity will be lost during the years in which the retrofit projects are underway due to extended outages at some plants where extensive modifications to the existing equipment are required. IN aggregate this could result in the need to replace about 500,000 GWh from other sources or over 10% of the national power systems output from fossil and nuclear steam plants.
- Some facilities will be unable to retrofit primarily due to severe space constraints.

A

STEAM ELECTRIC GENERATING STATIONS THAT WOULD HAVE BEEN DESIGNATED PHASE II FACILITIES UNDER THE REMANDED PHASE II RULE

Steam Electric Generating Stations That Would Have Been Designated Phase II Facilities Under the Remanded Phase II Rule (i.e. use >50 MGD of Cooling Water)
Notes Regarding the List
1. The list contains a small number of facilities that use once through cooling helper towers during a portion of the year.
2. The list is divided into nuclear and fossil facilities. However, three facilities Crystal River, H.B. Robinson and Waterford have both nuclear and fossil units.
3. For the facility to be on the list it must have an active NPDES permit, although the facility may not have operated in the last year or more. Two facilities have NPDES permits that allow once-through cooling that are still under construction.
4. In terms of Water Body Type: R = River, L/R = Freshwater Lake other than a Great Lake or Freshwater Reservoir, GL = Great Lakes and O/E/TR = Oceans/Estuary/Tidal River. The difference between a "Large" and "Small" River is that the mean annual flow of a large river exceeds 10,000 cfs.
5. It is important to note that some of the listed facilities identified as having once through cooling systems withdrawing cooling water from freshwater lakes and reservoirs may in fact be withdrawing from waterbodies that are considered part of a closed-cycle cooling system.
6. Table 1 provides the basis of the flow and MW data shown in columns 7 and 9. The flow basis for each facility is shown in column 6. If the basis of flow and MW data is rated 1 or 2 the facility owner/operator provided Unit specific data, such that the flow and MW data are only for once-through cooling units. If a facility flow basis is rated 3, 4 or 5 it is possible that the flow and MW for the facility include non once-through cooled units.

Table 1 - Priorities for Flow Basis
1 - Highest priority given to flow information provided in cost estimating worksheets specifically provided to inform the study.
2 - Second highest priority given to information provided by the Company or Facility based on 316(b) work that includes - PICs, 122.21r information, technology alternative assessments or other direct information on the facility.
3 - Third highest priority given to flow information provided in Appendix A&B of the Phase II Rule. This informaiton was provided in direct response to a 308 questionnaire.
4 - DOE or Internet

Facility Name	Utility	State	Plant Code	EPAID	Flow Basis	Flow (MGD)	Water Body Type	MW
Nuclear Facilities								
Arkansas Nuclear 1	Entergy	AR			2	1,146	L/R	900
Browns Ferry	Tennessee Valley Authority	AL	46	DUT1050	2	2,851	R (Large)	3,840
Brunswick	Progress Energy Carolinas	NC	6014	AUT0419	1	1,921	O/E/TR	2,060
Calvert Cliffs	Constellation Energy Group	MD	6011	DUT1268	2	3,629	O/E/TR	1,735
Clinton	AmerGen Energy Co LLC	IL	204	AUT0350	1	889	L/R	1,065
Comanche Peak	Luminant Power	TX	6145	DUT1022	2	3,168	L/R	2,300
Cooper	Nebraska Public Power District	NE	8036	AUT0255	2	983	R (Large)	802
Crystal River 3	Progress Energy Florida	FL	628	DUT1029	1	979	O/E/TR	890
Diablo Canyon	Pacific Gas & Electric Co	CA	6099	AUT0012	2	2,500	O/E/TR	2,298
Donald C. Cook	Indiana Michigan Power Co	MI	6000	AUT0202	1	2,369	GL	2,161
Dresden	Exelon Generation Co LLC	IL	869	AUT0364	1	1,898	R (Small)	1,914
Fitzpatrick (James A FitzPatrick)	Entergy Nuc FitzPatrick LLC	NY	6110	AUT0423	2	518	GL	852
Fort Calhoun	Omaha Public Power District	NE	2289	AUT0173	2	518	R (Large)	482
H.B. Robinson	Progress Energy	SC	3251		1	740	L/R	700
Indian Point	Entergy Nuclear Indian Point 2, LLC	NY	2497	AUT0541	2	2,419	O/E/TR	2,028
Kewaunee	Dominion Energy Kewaunee, Inc.	WI	8024	AUT0114	1	582	GL	595
McGuire	Duke Energy Corp	NC	6038	AUT0384	2	2,928	L/R	2,240
Millstone	Dominion Nuclear Conn Inc	CT	566	DUT1070	2	2,190	O/E/TR	2,205
Monticello	Xcel Energy	MN	1922	AUT0588	2	444	R (Large)	620

Facility Name	Utility	State	Plant Code	EPAID	Flow Basis	Flow (MGD)	Water Body Type	MW
Nine Mile Point, NY	Constellation Energy Group	NY	2589	AUT0403	2	517	GL	623
North Anna	Dominion Resources, Inc.	VA	6168	AUT0187	1	2,707	L/R	1,956
Oconee	Duke Energy Corp	SC	3265		2	3,058	L/R	2,538
Oyster Creek	AmerGen Energy Co LLC	NJ	2388	DUT1023	2	1,394	O/E/TR	630
Peach Bottom	Exelon Generation Co LLC	PA	3166	AUT0570	2	2,281	L/R	2,186
Pilgrim	Entergy Nuclear Generation Co	MA	1590	AUT0608	2	446	O/E/TR	706
Point Beach	NEXTera Energy	WI	4046	AUT0085	1	1,008	GL	1,365
Prarie Island	Xcel Energy	MN	1925	AUT0181	2	969	R (Large)	1,150
Quad Cities	Exelon Generation Co LLC	IL			2	1,356	R (Large)	1824
R. E. Ginna	Constellation Energy Group	NY	6122	AUT0190	2	536	GL	581
Salem	PSEG Nuclear LLC	NJ	2410	AUT0084	1	3,168	O/E/TR	2,540
San Onofre	Southern California Edison Co	CA	360	AUT0573	2	2,335	O/E/TR	2,150
Seabrook	NEXTera Energy	NH	6115	AUT0275	1	447	O/E/TR	1,296
Sequoyah	Tennessee Valley Authority	TN			2	1,616	L/R	2,442
St Lucie	NEXTera Energy	FL	6045		1	1,403	O/E/TR	1,700
Surry	Dominion Resources, Inc.	VA	3806	DUT1211	1	2,534	O/E/TR	1,802
V C Summer	South Carolina Electric & Gas Co. and SC Public Service Authority	SC	6127		1	720	L/R	1,100
Waterford 3	Entergy Louisiana Inc	LA	4270	AUT0513	2	1,555	R (Large)	1,165
Watts Bar	Tennessee Valley Authority	TN			2	194	L/R	1,270
Wolf Creek	Westar /KCPL	KS	210		2	698	L/R	1,220

Facility Name	Utility	State	Plant Code	EPAID	Flow Basis	Flow (MGD)	Water Body Type	MW
Fossil Facilities								
Aguirre	Puerto Rico Electric Power	PR	9999901		2	651	O/E/TR	900
Alamitos	AES Alamitos LLC	CA	315		2	1,181	O/E/TR	1,950
Allen	Tennessee Valley Authority	TN	2718	AUT0551	4	549	R (Large)	864
Allen S King	Xcel	MN	1915	AUT0551	2	467	L/R	605
Allen Steam	Duke Energy Corp	NC	3393		1	861	L/R	1,391
Alma/Magett	Dairyland Power Coop	WI	4140	DUT1021	1	540	R (Large)	605
Anclote	Progress Energy Florida	FL	8048	DUT1275	1	1,287	O/E/TR	1,030
Armstrong	Allegheny Energy Supply Co LLC	PA	3178		2	179	R (Large)	356
Arthur Kill	NRG Arthur Kill Power LLC	NY	2490		2	713	O/E/TR	875
Ashtabula	Cleveland Electric Illum Co	OH	2835		1	252	GL	256
Ashville	Progress Energy Carolinas	NC	2706		1	316	L/R	383
Astoria	Astoria Generating Co LP	NY	8906	AUT0603	3	1,769	O/E/TR	1,330
Avon Lake	RRI	OH	2836	AUT0245	1	625	GL	766
B C Cobb	Consumers Energy Co	MI	1695	AUT0021	2	583	GL	531
B L England (Beesley's Point)	Rockland Capital	NJ	2378	AUT0020	2	299	O/E/TR	299
Bailly	Northern Indiana Pub Serv Co	IN	995	DUT1093	1	490	GL	586
Barney M Davis	Topaz Power Group LLC	TX	4939	DUT1172	4	467	O/E/TR	682
Barry	Alabama Power Co	AL	3		1	1,119	O/E/TR	1,837
Bartow	Progress Energy Florida	FL	634	DUT1274	1	562	O/E/TR	419
Baxter Wilson	Entergy Mississippi Inc	MS	2050	AUT0571	1	297	R (Large)	1,328

Facility Name	Utility	State	Plant Code	EPAID	Flow Basis	Flow (MGD)	Water Body Type	MW
Bay Front	Xcel	WI	3982	AUT0499	2	63	GL	76
Bay Shore	First Energy	OH	2878		1	810	GL	849
Beaver Valley	AES Beaver Valley	PA	10676	AUT0125	2	145	R (Large)	125
Belews Creek	Duke Energy Corp	NC	8042		1	1,457	L/R	2,240
Belle River	Detroit Edison Co	MI	6034	AUT0163	2	950	GL	1,270
Big Bend	Tampa Electric Co	FL	645	DUT1165	4	1,396	O/E/TR	1,824
Big Brown	Luminant Power	TX	3497	AUT0449	2	1,015	L/R	1,150
Big Cajun 2	NRG Louisiana Generating LLC	LA	6055	AUT0500	1	380	R (Large)	615
Black Dog	Xcel	MN	1904		2	307	R (Small)	401
Blount Street	Madison Gas & Electric Co	WI	3992	AUT0427	3	170	L/R	195
Bowline Point	Mirant Bowline LLC	NY	2625		2	910	O/E/TR	1,150
Bremo Bluff	Dominion	VA	3796	AUT0396	1	179	R (Small)	250
Bridgeport Harbor	PSEG Power Connecticut LLC	CT	568	AUT0601	1	440	O/E/TR	566
Brooklin Navy Yard Cogen	Olympus Power, LLC	NY	54914	DNU2002	4	99	O/E/TR	80
Brunner Island	PPL Corp	PA	3140		1	795	R (Large)	1,483
Buck	Duke Energy Corp	NC	2720	AUT0490	1	395	R (Small)	487
Bull Run	Tennessee Valley Authority	TN	3396	AUT0024	2	590	L/R	911
Burlington	Interstate Power & Light Co (Alliant Energy)	IA	1104	AUT0585	1	116	R (Large)	212
Burns Harbor	International Steel Group	IN	10245		4	97	GL	176
C D McIntosh	Lakeland Electric Utility	FL	676	AUT0590	3	213	L/R	713
C P Crane	Constellation Power Source Gen	MD	1552	AUT0110	2	446	O/E/TR	385

Facility Name	Utility	State	Plant Code	EPAID	Flow Basis	Flow (MGD)	Water Body Type	MW
Cabras	Guam Power Authority	Guam	9999904		2	238	O/E/TR	210
Calaveris (O.W. Summers/J.T. Deely/J.K. Spruce)	CP San Antonio	TX	3611		2	2,249	L/R	3,200
Canaday	Nebraska Public Power District	NE	2226	AUT0246	2	97	R	125
Canal	Mirant Canal LLC	MA	1599		2	580	O/E/TR	1,175
Cane Run	Louisville Gas & Electric Co	KY	1363	AUT0001	1	370	R (Large)	645
Cape Canaveral	NEXTera Energy	FL	609		1	792	O/E/TR	500
Cape Fear	Progress Energy Carolinas	NC	2708	AUT0111	1	342	R (Small)	870
Cardinal	Cardinal Operating Co	OH	2828		1	1,152	R (Large)	1,200
Carl Bailey	Arkansas Electric Coop Corp	AR	202	DUT1170	2	98	R (Large)	124
Cayuga	AES Cayuga LLC	NY	1001		2	245	L/R	306
Cayuga	Duke Energy Corp	IN	2535		2	766	R	1,070
Cedar Bayou	NRG Energy, Inc.	TX	3460	DUT1238	1	1,132	O/E/TR	1,740
Chalk Point LLC	Mirant Mid-Atlantic LLC	MD	1571	AUT0049	2	720	O/E/TR	710
Chamois	Chamois	MO	2169	AUT0254	1	71	R (Large)	70
Charles R Lowman	Powersouth	AL	56	DUT1214	2	78	R	86
Chesapeake	Virginia Electric & Power Co	VA	3803	AUT0002	1	514	O/E/TR	604
Chesterfield	Virginia Electric & Power Co	VA	3797	AUT0299	1	1,091	O/E/TR	1,705
Cheswick	Orion Power Midwest LP - RRI Energy	PA	8226	AUT0106	1	376	R (Large)	637
Clay Boswell	Allete Inc	MN	1893		1	156	L/R	140
Cliffside	Duke Energy Corp	NC	2721	AUT0319	1	269	R (Small)	289

Facility Name	Utility	State	Plant Code	EPAID	Flow Basis	Flow (MGD)	Water Body Type	MW
Clifty Creek	Indiana-Kentucky Electric Corp	IN	983		1	1,434	R (Large)	1,306
Coffeen	Ameren Energy Generating Co	IL	861	DUT1152	2	575	L/R	1,005
Colbert	Tennessee Valley Authority	AL	47		2	1,325	R (Large)	1,332
Conesville	Columbus Southern Power Co	OH	2840		1	108	R (Small)	165
Conners Creek	Detroit Edison Co	MI	1726	AUT0285	2	213	GL	239
Contra Costa	Mirant Delta LLC	CA	228	AUT0621	2	440	O/E/TR	690
Costa Sur	Puerto Rico Electric Power	PR	9999908		2	874	O/E/TR	1,086
Covanta Mid-Connecticut Inc	Covanta Energy	CT	54945		3	75	L/R	90
Crawford	Midwest Generation EME LLC	IL	867	AUT0507	1	550	R (Small)	584
Crist	Gulf Power Co	FL	641		1	156	O/E/TR	150
Cromby	Exelon Generation Co LLC	PA	3159	DUT1185	1	359	R (Small)	380
Crystal River 1 and 2	Progress Energy Florida	FL	DUT1029		1	919	O/E/TR	900
Cumberland	Tennessee Valley Authority	TN	3399	DUT1132	2	2,730	R	2,650
Cutler	NEXTera Energy	FL	610	AUT0268	1	213	O/E/TR	237
Dale	East Kentucky Power Coop Inc	KY	1385	AUT0261	3	290	R (Small)	176
Dallman	Springfield City of	IL	963	AUT0537	4	353	L/R	388
Dan E Karn/J.C. Weadock	Consumers Energy Co	MI	1720	DUT1033	1	432	GL	515
Dan River	Duke Energy Corp	NC	2723		1	280	R (Small)	361
Danskammer	Dynegy	NY	2480		2	455	O/E/TR	493
Dave Johnston	PacifiCorp	WY	4158	AUT0583	2	193	R (Small)	454
Decker Creek	Austin Energy	TX	3548	AUT0151	3	695	L/R	726

Facility Name	Utility	State	Plant Code	EPAID	Flow Basis	Flow (MGD)	Water Body Type	MW
Deepwater	Conectiv Atlantic Generation LLC	NJ	3461	AUT0370	2	221	O/E/TR	166
Dickerson	Mirant Mid-Atlantic LLC	MD	1572		2	407	R (Small)	576
Dolphus M Grainger	South Carolina Pub Serv Auth	SC	3317	DUT1014	1	116	R (Small)	180
Dubuque	Interstate Power and Light (Alliant Energy)	IA	1046	AUT0277	2	82	R (Large)	77
Dunkirk	NRG Dunkirk Power LLC	NY	2554	AUT0620	2	576	GL	586
E C Gaston	Alabama Power Co	AL	26		1	832	R (Small)	1,000
E D Edwards	Ameren Energy Resources Generating	IL	856	DUT1111	2	579	R (Small)	780
E F Barrett	National Grid/KeySpan	NY	2511	AUT0168	2	294	O/E/TR	380
E S Joslin	NuCoastal Corporation	TX	3436	AUT0493	3	370	O/E/TR	261
E.J. Stoneman	DTE Stoneman, LLC	WI	4146		2	53	R (Large)	53
Eagle Valley-HT Pritchard	AES Corporation	IN	991	AUT0358	2	335	R (Small)	359
East River	Consolidated Edison Co-NY Inc	NY	2493	DUT1143	4	368	O/E/TR	599
Eastlake	First Energy	OH	2837		1	1,146	GL	1,594
Eaton	Southern Co.	MS	2046	AUT0440	1	108	R (Small)	68
Eddystone	Exelon Generation Co LLC	PA	3161	AUT0544	1	1,469	O/E/TR	1,570
Edge Moor	Conectiv Delmarva Generation Inc	DE	593	AUT0539	1	837	O/E/TR	705
Edgewater	Wisconsin Power & Light Co (Alliant Energy)	WI	4050	AUT0036	2	463	GL	770
Edwardsport	Duke Energy Corp	IN	1004		4	187	R (Small)	144
El Segundo	NRG - El Segundo Power LLC	CA	330	DNU2047	2	381	O/E/TR	941

Facility Name	Utility	State	Plant Code	EPAID	Flow Basis	Flow (MGD)	Water Body Type	MW
Elk River	GRE	MN	2039	AUT0244	1	73	R (Large)	195
Elmer Smith	Owensboro City of	KY	1374	DUT1041	2	265	R (Large)	441
Elrama	Orion Power Midwest LP - RRI Energy	PA	3098	DUT1047	1	518	R (Large)	510
Encina	NRG	CA	302	AUT0625	2	857	O/E/TR	964
F B Culley	Southern Indiana Gas & Elec Co	IN	1012	AUT0567	3	317	R (Large)	389
Fair Station	Central Iowa Power Coop	IA	1218	AUT0477	4	71	R (Large)	63
Fairless Hills	Exelon Generation Company, LLC	PA	7701		1	78	O/E/TR	60
Far Rockaway	National Grid/KeySpan	NY	2513	DUT1008	2	87	O/E/TR	106
Fayette	LCRA Fayette Power Project	TX	6179		2	1,165	L/R	1,641
Fisk Street	Midwest Generation EME LLC	IL	886	AUT0405	1	323	R (Small)	348
Flint Creek	Southwestern Electric Co	AR	6138		1	412	L/R	559
Forest Grove	Luminant Power	TX	9999925		2	1,470	L/R	1,500
Fort Myers	Florida Power & Light Co	FL	612	AUT0401	1	730	O/E/TR	573
Fox Lake	Interstate Power & Light Co (Alliant Energy)	MN	1888	DUT1175	2	101	L/R	98
Frank E Ratts	Hoosier Energy R E C Inc	IN	1043		2	102	R (Large)	256
G F Weaton	Zinc Corp of America	PA	50130		4	88	R (Large)	120
Gadsden	Alabama Power Co	AL	7		1	219	R (Small)	120
Gallatin	Tennessee Valley Authority	TN	3403	AUT0185	2	916	L/R	1,086
Gary Works	United States Steel Corp	IN	50733		4	122	GL	231
Genoa	Dairyland Power Coop	WI	4143	AUT0538	1	252	R (Large)	360

Facility Name	Utility	State	Plant Code	EPAID	Flow Basis	Flow (MGD)	Water Body Type	MW
George Neal North	MidAmerican Energy Co	IA	1091	AUT0397	2	791	R (Large)	1,046
George Neal South	MidAmerican Energy Co	IA	7343		2	468	R (Large)	640
Georgia Pacific Cedar Springs	Georgia-Pacific Corp	GA	54101		4	85	R (Small)	101
Gerald Andrus	Entergy Mississippi Inc	MS	8054	DUT1194	1	260	R (Large)	750
Gerald Gentleman	Nebraska Public Power District	NE	6077	AUT0257	2	760	R	1,444
GEUS	Greenville Electric Util Sys	TX	4195	AUT0481	5	84	L/R	84
Gibbons Creek	Texas Municipal Power Agency	TX	6136		4	418	L/R	454
Glen Lyn	Appalachian Power Co	VA	3776		1	373	R (Small)	335
Glenwood	National Grid/KeySpan	NY	2514	DUT1186	2	179	O/E/TR	218
Gorgas	Alabama Power Co	AL	8		1	979	R	1,221
Gould Street	Constellation Energy Group	MD	1553	AUT0529	2	99	O/E/TR	97
Graham	Luminant Power	TX	3490	DUT1072	2	505	L/R	630
Grand Tower	Ameren Energy Generating Co	IL	862	DUT1012	2	229	R (Large)	199
Grays Ferry	Trigen Phildelphia Energy Corp	PA	54785	DNU2018	3	64	O/E/TR	58
Green Bay West Mill	Fort James Operating Co	WI	10360		4	120	R (Small)	136
Green River	Kentucky Utilities Co	KY	1357	DUT1261	1	177	R (Small)	231
Greene County	Alabama Power Co	AL	10		1	396	R (Small)	500
Greenidge	AES Greenidge LLC	NY	2527		2	146	L/R	107
H.A. Wagner	Constellation Power Source Gen	MD	1554	AUT0174	2	1,060	O/E/TR	982
H L Culbreath Bayside	Tampa Electric Co	FL	646	DUT1066	3	2,465	O/E/TR	685
H.B. Robinson	Progress Energy	SC	3251		1	126	L/R	185

Facility Name	Utility	State	Plant Code	EPAID	Flow Basis	Flow (MGD)	Water Body Type	MW
Hamilton	Hamilton City of	OH	2917	AUT0333	3	485	R (Small)	111
Hammond	Georgia Power	GA	708	AUT0131	1	548	L/R	800
Handley	ExTex LaPorte LP	TX	3491	AUT0284	1	1,121	L/R	1,315
Harbor	LADWP	CA	399	DUT1068	2	108	O/E/TR	75
Harbor Beach	Detroit Edison Co	MI	1731	DUT1138	2	130	GL	103
Harding Street	Indianapolis Power & Light Co	IN	990		2	238	R	360
Harllee Branch	Georgia Power	GA	709	AUT0298	1	1,139	L/R	1,735
Hawthorn	Kansas City Power & Light Co	MO	2079	AUT0361	2	283	R (Largel)	693
Haynes	LADWP	CA	400	AUT0387	2	1,014	O/E/TR	1,279
Healy	Golden Valley Electric Association	AK	6288	AUT0381	2	53	R (Small)	75
Hennepin	Dynegy Midwest Generation Inc	IL	892	AUT0004	2	230	R (Small)	293
Henry D King	Fort Pierce Utilities Auth	FL	658	AUT0067	4	108	O/E/TR	114
Hibbard	Minnesota Power Inc	MN	1897		1	236	GL	124
High Bridge	Xcel	MN	1912	AUT0228	2	390	R	510
Honolulu	Hawaiian Electric Co Inc	HI	764	DUT1145	1	184	O/E/TR	103
Hoot Lake	Otter Tail Power Co	MN	1943		4	116	R (Small)	137
Horseshoe Lake	Oklahoma Gas & Electric Co	OK	2951		2	400	L/R	396
Hudson	PSEG Fossil LLC	NJ	2403	DUT1169	1	892	O/E/TR	983
Humboldt Bay	PG&E	CA	246	AUT0517	3	142	O/E/TR	102
Hunlock	UGI	PA			2	61	R (Small)	50
Huntington Beach	AES Huntington Beach LLC	CA	335	AUT0612	2	514	O/E/TR	880

Facility Name	Utility	State	Plant Code	EPAID	Flow Basis	Flow (MGD)	Water Body Type	MW
Huntley	NRG Huntley Power LLC	NY	2549	AUT0604	1	346	GL	816
Hutsonville	Ameren Energy Generating Co	IL	863	AUT0385	2	173	R (Large)	167
Iatan	Kansas City Power & Light Co	MO	6065	AUT0398	2	425	R (Large)	706
Indian River	RRI Energy Florida LLC	FL	55318	AUT0496	2	835	R (Small)	609
Indian River	NRG Indian River Operations Inc	DE	594	DUT1206	1	378	O/E/TR	432
J B Sims	Grand Haven BL&P	MI	1825	AUT0241	4	60	GL (Small)	75
J E Corette	PPL Montana LLC	MT	2187	AUT0321	1	75	R (Small)	154
J H Campbell	Consumers Energy Co	MI	1710	AUT0191	1	936	GL	1,440
J M Stuart	Dayton Power & Light Co	OH	2850	DUT1212	1	904	R (Large)	1,869
J R Whiting	Consumers Energy Co	MI	1723	DUT1133	2	323	GL	328
J Sherman Cooper	East Kentucky Power Coop Inc	KY	1384		4	208	R (Large)	341
J.P. Pulliam	Wisconsin Public Service Corp	WI	4072	AUT0157	2	523	GL	373
Jack Watson	Mississippi Power Co	MS	2049	AUT0501	1	441	O/E/TR	512
James De Young	Holland Board of Public Works	MI	1830	DUT1259	3	103	GL	63
James River	Springfield City of	MO	2161	AUT0518	3	279	L/R	253
Jefferies	South Carolina Pub Serv Auth	SC	3319	AUT0522	1	357	O/E/TR	508
John Sevier	Tennessee Valley Authority	TN	3405	DUT1156	2	714	R (Small)	816
Johnsonville	Tennessee Valley Authority	TN	3406	AUT0337	2	1,601	R (Large)	1,408
Joliet 29	Midwest Generation EME LLC	IL	384	AUT0193	1	1,424	R (Small)	1,189
Joliet 9	Midwest Generation EME LLC	IL	874	AUT0205	1	438	R (Small)	341
Joppa Steam	Electric Energy Inc	IL	887	DUT1049	4	589	R (Large)	1,100

Facility Name	Utility	State	Plant Code	EPAID	Flow Basis	Flow (MGD)	Water Body Type	MW
Kahe	Hawaiian Electric Co Inc	HI	765	AUT0305	1	847	O/E/TR	650
Kammer	Ohio Power Co	WV	3947		1	713	R (Large)	630
Kanawha River	Appalachian Power Co	WV	3936		1	403	R (Large)	426
Kaw	Board of Public Utilities-City of Kansas	KS	1294	AUT0368	3	120	R	166
Kendall	Mirant Kendall LLC	MA	1595	AUT0623	2	78	R (Small)	67
Kenneth C Coleman	Western Kentucky Energy Corp	KY	1381		4	335	R (Large)	521
Kincaid	Dominion Energy	IL	876		1	461	L/R	1,182
Kingston	Tennessee Valley Authority	TN	3407	AUT0552	2	1,495	R (Small)	1,677
Knox Lee	Southwestern Electric Power Co	TX	3476	DUT1248	1	639	L/R	500
Kraft	Savannah Electric & Power Co	GA	733		1	259	O/E/TR	479
Kyger Creek	Ohio Valley Electric Corp	OH	2876	AUT0564	1	1,166	R (Large)	1,085
Kyrene	Salt River Proj Ag I & P Dist	AZ	147		2	96	OTHER	96
La Cygne	Kansas City Power & Light Co	KS	1241		2	726	L/R	1,418
Labadie	Ameren UE	MO	2103	DUT1046	2	1,233	R (Large)	2,560
Lake Catherine	Entergy Arkansas Inc	AR	170	AUT0073	2	565	L/R	673
Lake Hubbard	Luminant Power	TX	3452	AUT0027	2	870	L/R	921
Lake Road	Kansas City Power & Light Co	MO	2098	AUT0127	2	86	R(Large)	99
Lake Shore	Cleveland Electric Illum Co	OH	2838		1	246	GL	256
Lansing	Interstate Power & Light Co (Alliant Energy)	IA	1047	AUT0304	2	299	R (Large)	317
Lansing Smith	Southern Co.	FL	679	AUT0304	1	260	O/E/TR	384

Facility Name	Utility	State	Plant Code	EPAID	Flow Basis	Flow (MGD)	Water Body Type	MW
Lauderdale	Florida Power & Light Co	FL	613	AUT0142	1	368	O/E/TR	312
Leland Olds	Basin Electric Power Coop	ND	2817	DUT0062	1	330	R (Large)	656
Lieberman	SWEPCO	LA	1417		1	134	L/R	286
Little Gypsy	Entergy Louisiana Inc	LA	1402	AUT0097	1	468	R (Large)	1,251
Lonestar	Southwestern Electric Power Co	TX	3477	AUT0080	4	79	L/R	40
Maine Energy Recovery Co	Central Maine Power Co	ME	10338	DNU2013	3	94	O/E/TR	22
Manchester Street	Narraganset Electric Co	RI	3236		1	259	O/E/TR	168
Mandalay	RRI Energy Mandalay LLC	CA	345	AUT0638	2	254	O/E/TR	430
Manitowoc	Manitowoc Public Utilities	WI	4125	DUT1202	3	52	GL	79
Marion	Southern Illinois Power Coop	IL	976	AUT0222	3	225	L/R	272
Marshall	Duke Energy Corp	NC	2727	AUT0260	2	1,463	L/R	2,090
Martin Lake	Luminant Power	TX	6146	AUT0176	2	2,411	L/R	2,250
Marysville	Detroit Edison Co	MI	1732		4	368	GL	84
McClellan	Arkansas Electric Coop Corp	AR	203	DUT1154	2	71	R (Small)	136
McIntosh	Georgia Power	GA	6124		1	91	R (Small)	167
McManus	Georgia Power	GA	715		1	166	O/E/TR	115
Meramec	Ameren UE	MO	2104	DUT1192	2	675	R (Large)	1,035
Mercer	PSEG Fossil LLC	NJ	2408	AUT0058	1	691	O/E/TR	648
Meredosia	Ameren Energy Generating Co	IL	864	AUT0146	2	392	R (Large)	354
Merom	Hoosier Energy R E C Inc	IN	6213	AUT0406	1	484	L/R	1,139
Merrimack	Public Service Co of NH	NH	2364	DUT1031	3	287	R (Small)	474

Facility Name	Utility	State	Plant Code	EPAID	Flow Basis	Flow (MGD)	Water Body Type	MW
Miami Fort	Duke Energy Corp	OH	2832	AUT0472	2	130	R (Large)	163
Michoud	Entergy New Orleans Inc	LA	1409	AUT0047	2	763	O/E/TR	918
Mid Connecticut Resource Recovery Facility	Connecticut Resources Recovery Authority	CT	9999926		4	108	R(Large)	90
Middletown	NRG Middletown Power LLC	CT	562	AUT0577	1	224	R (Large)	353
Mill Creek	Louisville Gas & Electric Co	KY	1364	DUT1153	1	233	R (Large)	419
Milton L Kapp	Interstate Power & Light Co (Alliant Energy)	IA	1048	AUT0443	2	197	R (Large)	255
Milton R Young	Minnkota Power Coop Inc	ND	2823	DUT1103	1	530	L/R	700
Missouri City	Independent Blue Valley Power Plant	MO	2171	AUT0078	3	416	R (Largel)	46
Mistersky	Detroit City of	MI	1822	AUT0433	4	198	GL	189
Mitchell	Georgia Power	GA	727	AUT0137	1	173	R (Small)	125
Mitchell	Allegheny Energy Supply Co LLC	PA	3181	AUT0404	2	255	R (Large)	365
Monroe	Detroit Edison Co	MI	1448	DUT1002	3	2,010	GL and R	3,110
Monticello	Luminant Power	TX	6147	DUT1272	2	1,732	L/R	1,880
Montrose	Kansas City Power & Light Co	MO	2080	AUT0341	2	370	L/R	510
Montville	NRG Montville Power LLC	CT	546	AUT0013	1	315	O/E/TR	516
Morgantown	Dominion Energy Services Company, Inc.	WV	10743	AUT0278	1	80	R (Large)	58
Morgantown	Mirant Mid-Atlantic LLC	MD	1573	DNU2021	2	1,234	O/E/TR	1,248
Morro Bay	Dynegy	CA	259	AUT0613	2	453	O/E/TR	600
Moss Landing	Dynegy	CA	260	AUT0607	1	1,224	O/E/TR	1,899

Facility Name	Utility	State	Plant Code	EPAID	Flow Basis	Flow (MGD)	Water Body Type	MW
Mount Tom	Northeast Generation Services Co	MA	1606	AUT0134	3	143	R (Large)	144
Mountain Creek	ExTex LaPorte LP	TX	3453	DUT1187	1	722	L/R	810
Mt Storm	Virginia Electric & Power Co	WV	3954	AUT0178	1	1,184	L/R	1,693
Muscatine Plant #1	Muscatine City of	IA	1167	AUT0033	4	288	R (Large)	294
Muskingum River	Ohio Power Co	OH	2872	AUT0547	1	864	R (Small)	840
Muskogee	Oklahoma Gas & Electric Co	OK	2952	DUT1252	2	107	R (Small)	180
Mystic (Unit 7)	U.S. Power Gen	MA	1588		4	646	O/E/TR	560
Natrium Plant	PPG Industries Inc	WV	50491		4	65	R (Large)	123
Nebraska City	Omaha Public Power District	NE	6096	AUT0394	2	432	R (Large)	653
Nelson Dewey	Wisconsin Power & Light Co (Alliant Energy)	WI	4054	AUT0053	2	167	R (Large)	200
New Castle Plant	RRI Energy	PA	3138	AUT0208	1	253	R (Small)	348
New Haven Harbor	PSEG Power Connecticut LLC	CT	6156	AUT0618	1	404	O/E/TR	466
New Madrid	Associated Electric Coop Inc	MO	2167	AUT0171	1	864	R (Large)	1,200
Newington	Public Service Co of NH	NH	8002		4	325	O/E/TR	422
Newton	Ameren Energy Generating Co	IL	6017		2	806	L/R	1,288
Niles	RRI	OH	2861		1	403	R (Small)	266
Nine Mile Point	Entergy Louisiana Inc	LA	1403	AUT0403	1	611	R (Large)	1,566
Noblesville	Duke Energy Corp	IN	1007	AUT0416	3	207	R (Small)	100
North Omaha	Omaha Public Power District	NE	2291	AUT0266	2	529	R (Large)	664
North Texas	Brazos Electric Power Coop Inc	TX	3627	DUT1038	3	95	L/R	71

Facility Name	Utility	State	Plant Code	EPAID	Flow Basis	Flow (MGD)	Water Body Type	MW
Northport	National Grid/KeySpan	NY	2516	AUT0015	2	926	O/E/TR	1,500
Northside	JEA	FL	667	AUT0568	1	648	O/E/TR	1,159
Norwalk Harbor	NRG Norwalk Harbor Power LLC	CT	548	AUT0120	2	312	O/E/TR	330
O H Hutchings	Dayton Power & Light Co	OH	2848	DUT1198	3	403	R	399
Oak Creek	Wisconsin Electric Power Co	WI	4041	DUT1034	1	1,181	GL	1,139
Oak Grove	Luminant Power	TX	9999927		2	1,610	L/R	1,710
Ormond Beach	RRI Energy Ormond Beach, Inc.	CA	350	AUT0637	2	685	O/E/TR	1,516
Oswego Harbor	NRG Oswego Power LLC	NY	2594	AUT0071	1	1,132	GL	1,740
Otto E. Eckert	Lansing Board of Water and Light	MI	1831	AUT0300	2	233	R (Small)	330
P H Robinson	NRG Energy, Inc.	TX	3466	DUT1155	1	1,681	O/E/TR	2,285
Palo Seco	Puerto Rico Electric Power	PR	9999920		2	654	O/E/TR	602
Paradise	Tennessee Valley Authority	KY			2	608	R(Small)	2,427
Peru	Peru Light & Power Co	IN	1037	DUT1003	3	55	R (Large)	35
Petersburg	Indianapolis Power & Light Co	IN	994	DUT1085	2	428	R (Large)	880
Philip Sporn	Central Operating Co	WV	3938	AUT0314	1	1,038	R (Large)	1,050
Picway	Columbus Southern Power Co	OH	2843		1	101	R (Small)	100
Pirkey	SWEPCO	TX	7902		1	544	L/R	700
Pittsburg	Mirant Delta LLC	CA	271	AUT0639	2	462	O/E/TR	645
Port Everglades	Florida Power & Light Co	FL	617		1	1,253	O/E/TR	1,254
Port Jefferson	National Grid/KeySpan	NY	2517		2	294	O/E/TR	380
Port Washington	Wisconsin Electric Power Co	WI	4040	DUT1219	1	814	GL	1,206

Facility Name	Utility	State	Plant Code	EPAID	Flow Basis	Flow (MGD)	Water Body Type	MW
Portland	RRI Energy Mid-Atlantic PH	PA	3113	AUT0351	1	314	R (Small)	427
Possum Point	Virginia Electric & Power Co	VA	3804	AUT0270	1	224	O/E/TR	313
Potomac River	Mirant Mid-Atlantic LLC	VA	3788	AUT0554	2	450	O/E/TR	510
Prairie Creek	Interstate Power & Light Co (Alliant Energy)	IA	1073	AUT0181	2	205	R (Small)	238
Presque Isle	Wisconsin Electric Power Co	MI	1769	DUT1007	1	350	GL	450
Quindaro	Kansas City City of	KS	1295	AUT0297	3	265	R (Large)	239
R A Reid	Big River Energy Corp.	KY	1383		5	130	R (Small)	96
R E Burger	Ohio Edison Co	OH	2864	AUT0175	1	225	R (Large)	416
R Gallagher	Duke Energy Corp	IN	1008		2	436	R (Large)	616
R M Heskett	MDU Resources Group Inc	ND	2790	DUT1154	4	64	R (Large)	115
R Paul Smith	Allegheny Energy Supply Co LLC	MD	1570		2	103	R (Small)	116
R W Miller	Brazos Electric Power Coop Inc	TX	3628	AUT0192	4	396	L/R	604
Ravenswood	TransCanada	NY	2500	AUT0617	2	1,390	O/E/TR	1,752
Ray Olinger	Garland City of	TX	3576	DUT1043	2	357	L/R	345
Red Wing	Xcel	MN	1926		2	50	R	26
Redondo Beach	AES Redondo Beach LLC	CA	356		1	891	O/E/TR	1,310
Richard Gorsuch	American Mun Power-Ohio Inc	OH	7286	AUT0446	1	187	R (Large)	213
River Rouge	Detroit Edison Co	MI	1740	AUT0276	2	441	GL	540
Riverbend	Duke Energy Corp	NC	2732		1	415	L/R	470
Riverside	Constellation	MD	1927	AUT0203	2	61	O/E/TR	78
Riverside	MidAmerican Energy Co	IA	1081	AUT0203	2	90	R	141

Facility Name	Utility	State	Plant Code	EPAID	Flow Basis	Flow (MGD)	Water Body Type	MW
Riverside	Xcel	MN	1559	AUT0203	2	277	R (Large)	420
Riverton	Empire District Electric	KS	1239	DUT1229	3	105	R	88
Rivesville	Monongahela Power Co	WV	3945		2	119	R (Large)	137
Riviera	NEXTera Energy	FL	619		1	565	O/E/TR	600
Robert E Ritchie	Entergy Arkansas Inc	AR	173	DUT1161	1	454	R (Large)	919
Roseton	Dynegy	NY	8006	AUT0411	2	924	O/E/TR	1,185
Roxboro	Progress Energy Carolinas	NC	2712		1	1,096	L/R	1,775
Rush Island	Ameren UE	MO	6155	AUT0536	2	1,097	R (Large)	1,340
S O Purdom	Tallahassee City of	FL	689	DUT0576	3	134	O/E/TR	137
Sabine	Entergy Gulf States Inc	TX	3459	AUT0315	1	1,275	L/R	2,167
Salem Harbor	Dominion	MA	1626	AUT0631	3	692	O/E/TR	745
Sam Gideon/Lost Pines 1	LCRA	TX	3601	DUT1273	2	950	L/R	1,165
San Juan	Puerto Rico Electric Power	PR	9999924		2	749	O/E/TR	534
Sanford	Florida Power & Light Co	FL	620		1	167	R (Small)	156
Scattergood	Los Angeles City of	CA	404	AUT0068	2	495	O/E/TR	838
Schiller	Public Service Co of NH	NH	2367	AUT0083	4	153	O/E/TR	160
Scholz	Southern Co.	FL	642		1	130	R (Large)	80
Schuylkill	Exelon Generation Co LLC	PA	3169	AUT0183	1	207	O/E/TR	228
Seminole	Oklahoma Gas & Electric Co	OK	2956		2	1,434	L/R	1,500
Sewaren	PSEG Fossil LLC	NJ	2411	DUT1100	1	542	O/E/TR	428
Shawnee	Tennessee Valley Authority	KY	1379	AUT0483	2	1,613	R (Large)	1,610

Facility Name	Utility	State	Plant Code	EPAID	Flow Basis	Flow (MGD)	Water Body Type	MW
Shawville	RRI Energy Mid-Atlantic PH	PA	3131	AUT0011	1	656	R (Large)	626
Shiras	Marqutte Board of Light and Power	MI	1843	AUT0435	3	264	GL	78
Sibley	Kansas City Power & Light Co	MO	2094	DUT1227	2	293	R (Large)	466
Silver Bay Power	Cleveland Cliffs Inc	MN	10849		4	151	GL	132
Silver Lake	Rochester Public Utilities	MN	2008	AUT0227	3	119	L/R	106
Sioux	Ameren UE	MO	2107	AUT0072	2	749	R (Large)	1,100
Somerset (Formerly Kintigh)	AES Somerset LLC	NY	6082		2	274	GL	675
Somerset	NRG Somerset Power LLC	MA	1613	AUT0384	4	274	O/E/TR	174
Sooner	Oklahoma Gas & Electric Co	OK	6095		2	789	L/R	1,096
South Bay	Dynegy	CA	310		1	517	O/E/TR	696
SR Bertron	NRG Energy, Inc.	TX	3468	AUT0248	1	740	O/E/TR	861
St Clair	Detroit Edison Co	MI	1743	DUT1258	1	1,111	GL	1,414
Stanton	Great River Energy	ND	2824	AUT0273	1	144	R (Largel)	202
State Line Energy	State Line Energy LLC	IN	981		1	621	GL	1,711
Sterlington	Entergy Louisiana Inc	LA	1404	DUT1157	1	158	R (Small)	224
Stryker Creek	Luminant Power	TX	3504	DUT1011	2	527	L/R	675
Sunbury Gen	Corona Power LLC	PA	3152		4	296	R (Large)	425
Suwannee	Progress Energy Florida	FL	638	AUT0051	1	261	R (Small)	217
Syl Laskin	Allete Inc	MN	1891		1	136	L/R	110
Taconite Harbor	Allete Inc	MN	10075		1	184	GL	225

Facility Name	Utility	State	Plant Code	EPAID	Flow Basis	Flow (MGD)	Water Body Type	MW
Tanners Creek	Indiana Michigan Power Co	IN	988	AUT0148	1	1,066	R (Large)	995
Teche	Cleco Power LLC	LA	1400	AUT0362	3	451	O/E/TR	428
Tennessee Eastman Operations	Eastman Chemical Co-TN Ops	TN	50481		4	674	R	194
Thames	AES Thames LLC	CT	10675		2	156	R (Small)	181
Thomas B Fitzhugh	Arkansas Electric Cooperative Corp	AR	201		2	61	R (Small)	60
Thomas C Ferguson	Lower Colorado River Authority	TX	4937		4	397	L/R	446
Thomas Hill	Associated Electric Coop Inc	MO	2168	AUT0149	1	1,002	L/R	1,197
Trenton Channel	Detroit Edison Co	MI	1745	AUT0575	2	516	GL	730
Trinidad	Luminant Power	TX	3507	AUT0476	2	285	L/R	240
Twin Oaks	Sempra	TX			5	305	L/R	330
Tyrone	Kentucky Utilities Co	KY	1361	AUT0095	1	79	R (Small)	75
University of Notre Dame	Indiana Michigan Power Co	IN	50366	DMU3244	3	113	L/R	21
Urquhart	South Carolina Electric&Gas Co	SC	3295	AUT0535	1	190	R (Small)	243
V H Braunig	CP San Antonio	TX	3612		2	1,277	L/R	1,401
Valley	Wisconsin Electric Power Co	WI	3508	AUT0161	1	158	GL	280
Valmont	Xcel	CO			2	194	L/R	186
Vero Beach	Vero Beach City of	FL	693	AUT0467	4	144	O/E/TR	117
Victoria	Topaz Power Group LLC	TX	3443	DUT1142	4	557	R	80
W H Sammis	Ohio Edison Co	OH	2866		1	1,353	R (Large)	2,219
W S Lee	Duke Energy Corp	SC	3264	AUT0308	1	331	R (Small)	424

Facility Name	Utility	State	Plant Code	EPAID	Flow Basis	Flow (MGD)	Water Body Type	MW
Wabash River	Duke Energy Corp	IN	1010		2	747	R (Large)	764
Waiau	Hawaiian Electric Co Inc	HI	766	DUT1116	1	430	O/E/TR	397
Walter C Beckjord	Duke Energy Corp	OH	2830	AUT0523	1	741	R (Large)	1,222
Walter Scott Jr. (Council Bluffs)	MidAmerican Energy Co	IA	1082	DUT1148	2	792	R (Largel)	821
Warrick	Alcoa Power Generating Inc	IN	6705	AUT0462	4	281	R (Large)	755
Waterford 1 & 2	Entergy Louisiana Inc	LA	8056	AUT0156	1	822	R (Large)	912
Waukegan	Midwest Generation EME LLC	IL	883	DUT1123	1	731	GL	736
Welsh	SWEPCO	TX	6139		1	1,218	L/R	1,674
West Springfield	North American Energy Alliance	MA	1642		4	69	R (Large)	214
Westchester Resco Co	Westchester Resco/Wheelabrator	NY	50882	DNU2017	3	55	O/E/TR	75
Weston	Wisconsin Public Service Corp	WI	4078	AUT0344	2	118	R (Small)	135
Westover	AES Westover LLC	NY	2526		2	97	R (Large)	82
Widows Creek	Tennessee Valley Authority	AL	50	DUT1209	2	1,645	R (Large)	1,761
Wilkes	SWEPCO	TX	3478		1	539	L/R	888
Will County	Midwest Generation EME LLC	IL	884	AUT0380	1	1,296	R (Small)	1,300
Williams	South Carolina Genertg Co Inc	SC	3298	AUT0014	1	534	L/R	656
Willow Glen	Entergy Gulf States Inc	LA	1394	DUT1228	1	1,002	R (Large)	2,045
Willow Island	Monongahela Power Co	WV	3946		2	205	R (Large)	245
Wood River	Dynegy Midwest Generation Inc	IL	898	AUT0143	2	340	R (Large)	460
Wyandotte	Wyandotte City of	MI	1866	AUT0050	4	112	GL	73
Wyman	NEXTera Energy	ME	1507		1	263	O/E/TR	837
Yorktown	Virginia Electric & Power Co	VA	3809		1	1,382	O/E/TR	1,230

B
PLANTS WITH INDEPENDENT COST INFORMATION

Nuclear Facilities					
Plant ID	Plant Capacity	Circulating Water Flow	Source Water		Location
	MW	GPM	Water Type	Salinity	Region
N100	2,060	1,333,734	O/E/TR (Small)	BR	Mid-Atlantic
NUC1	2,350	1,261,000	R (Large)	FR	Mid-West
N475	1,735	1,220,000	O/E/TR	SA	Mid-Atlantic
N416	890	680,000	O/E/TR	SA	Southeast
N285	2,080	1,485,000	GL	FR	North Central
N321	2,298	1,736,111	O/E/TR	SA	Pacific
N477	1,914	1,017,000	R (Small)	FR	Mid-West
N145	2,045	1,680,484	O/E/TR (Large)	BR	Northeast
N178	1,956	1,880,000	L	FR	Mid-Atlantic
N506	630	968,333	O/E/TR	SA	Northeast
NUC2	812	387,000	GL	FR	North Central
N218	2,540	2,200,000	O/E/TR (Small)	BR	Northeast
N302	2,150	1,621,528	O/E/TR	SA	Pacific
N233	1,296	310,416	O/E/TR	SA	Northeast
N459	1,700	974,600	O/E/TR	SA	Southeast
N236	1,801.80	1,760,000	O/E/TR (Small)	BR	Mid-Atlantic

Fossil Facilities					
Plant ID	Plant Capacity	Circulating Water Flow	Source Water		Location
	MW	GPM	Water Type	Salinity	Region
F439	1,950	820,139	O/E/TR	SA	Pacific
FOS1	292	154,000	R (Large)	FR	Mid-Atlantic
F515	875	495,139	O/E/TR	SA	Northeast
F244	682	324,306	O/E/TR	BR	South Central
F458	1,824	969,472	O/E/TR	SA	Southeast
F452	1,600	902,778	O/E/TR (Small)	BR	Northeast
F289	911	417,000	L	FR	Southeast
F537	804	550,000	O/E/TR (Small)	BR	Southeast
F387	870	117,600	R (Small)	FR	Mid-Atlantic
F437	1,200	800,000	R (Large)	FR	Mid-West
F461	1,306	996,000	R (Large)	FR	Mid-West
F453	1,332	920,000	R (Large)	FR	Southeast
F153	165	75,000	R (Small)	FR	Mid-West
F228	690	305,556	O/E/TR	BR	Pacific
F232	584	382,000	O/E/TR	BR	Mid-Atlantic
F277	584	382,000	R (Small)	FR	Mid-West
F493	2,650	1,896,000	R	FR	Southeast
F318	237	148,000	O/E/TR	SA	Southeast
F283	586	400,000	GL	FR	Northeast
F204	941	264,800	O/E/TR	SA	Pacific
F382	348	224,306	R (Small)	FR	Mid-West
F522	573	507,000	O/E/TR	BR	Southeast
F406	1,086	636,000	L	FR	Southeast
F275	800	380,000	R (Small)	FR	Southeast
F155	75	75,000	O/E/TR	SA	Pacific
F420	1,279	704,167	O/E/TR	SA	Pacific
F423	983	736,220	O/E/TR	BR	Mid-Atlantic
F402	983	620,000	O/E/TR (Small)	BR	Northeast
F256	880	356,944	O/E/TR	SA	Pacific
F388	816	240,000	GL	FR	Northeast
F517	816	496,000	R (Small)	FR	Southeast

Fossil Facilities					
Plant ID	Plant Capacity	Circulating Water Flow	Source Water		Location
	MW	GPM	Water Type	Salinity	Region
F469	1,408	1,112,000	R (Large)	FR	Southeast
F460	1,189	988,890	R (Small)	FR	Mid-West
F226	341	304,167	R (Small)	FR	Mid-West
F516	630	495,000	R (Large)	FR	Mid-Atlantic
F210	426	280,000	R (Large)	FR	Mid-Atlantic
F241	1,182	320,016	Reservoir	FR	Mid-West
F467	1,677	1,038,000	R (Small)	FR	Southeast
F438	1,085	810,000	R (Large)	FR	Mid-West
F394	312	255,554	O/E/TR	SA	Southeast
F341	430	176,389	O/E/TR	SA	Pacific
F363	474	199,306	R	FR	Northeast
FOS3	598	272,000	R	FR	Southeast
F237	600	314,800	O/E/TR	SA	Pacific
F445	1,899	850,000	O/E/TR	SA	Pacific
F549	840	600,000	R (Small)	FR	Mid-West
FOS2	235	144,000	R (Small)	FR	Mid-West
F373	325	300,000	O/E/TR	BR	Northeast
F483	2,493	1,492,000	GL	FR	North Central
F509	1,516	475,694	O/E/TR	SA	Pacific
F421	1,050	721,000	R (Large)	FR	Mid-Atlantic
F146	100	70,000	R (Small)	FR	Mid-West
F408	506	642,000	O/E/TR	BR	Pacific
F449	1,254	870,000	O/E/TR	SA	Southeast
F281	665	392,000	O/E/TR	BR	Southeast
F540	2,167	560,500	L	FR	South Central
F194	156	116,000	R (Small)	FR	Southeast
F252	838	343,750	O/E/TR	SA	Pacific
F168	160	106,250	O/E/TR	BR	Northeast
F505	626	455,200	R (Large)	FR	Northeast
F424	995	740,000	R (Large)	FR	Mid-West
F546	976	588,067	GL	FR	Mid-West
F472	1,761	1,560,000	R (Large)	FR	Southeast
F451	1,300	900,000	GL	FR	Mid-West
F348	837	182,636	O/E/TR	SA	Northeast
FOS5	681	420,000	R (Small)	FR	Southeast

C
PLANTS WITH COMPLETED WORKSHEETS

Nuclear Facilities					
Plant ID	Plant Capacity	Circulating Water Flow	Source Water		Location
	MW	GPM	Water Type	Salinity	Region
N100	2,060	1,333,734	O/E/TR (Small)	Brackish	Mid- Atlantic
N416	890	680,000	O/E/TR	Saline	Southeast
N321	2,298	1,736,111	O/E/TR	Saline	Pacific
N285	2,161	1,645,000	GL	Fresh	North Central
N477	1,914	1,017,000	R (Small)	Fresh	Midwest
N145	2,045	1,680,484	O/E/TR (Large)	Saline	Northeast
N486	595	404,188	GL	Fresh	North Central
N253	1,778	343,750	GL	Fresh	Northeast
N178	1,956	1,880,000	L	Fresh	Mid- Atlantic
N506	630	968,333	O/E/TR	Brackish	Mid- Atlantic
N473	2,285	#REF!	O/E/TR	Brackish	South Central
N419	1,365	700,000	GL	Fresh	North Central
N269	581	372,000	GL	Fresh	Northeast
N218	2,540	2,200,000	O/E/TR (Small)	Bracksih	Mid- Atlantic
N302	2,150	1,621,528	O/E/TR	Saline	Pacific
N233	1,296	310,416	O/E/TR	Saline	Northeast
N459	1,700	974,600	O/E/TR	Saline	Southeast
N236	1,802	1,760,000	O/E/TR (Small)	Brackish	Mid- Atlantic
N520	966	512,986	L	Fresh	Southeast

Fossil Facilities					
Plant ID	Plant Capacity	Circulating Water Flow	Source Water		Location
	MW	GPM	Water Type	Salinity	Region
F439	1,950	820,139	O/E/TR	Brackish	Southeast
F276	864	381,000	R (Large)	Fresh	Mid Atlantic
F271	605	375,000	R (Large)	Fresh	Mid Atlantic
F450	1,030	894,000	O/E/TR	Brackish	Southeast
F338	256	175,000	GL	Fresh	Midwest
F380	837	219,600	L	Fresh	Southeast
F296	766	434,000	GL	Fresh	Northeast
F251	586	340402	GL	Fresh	Mid Atlantic
F431	1,837	777,000	O/E/TR	Brackish	Pacific
F280	960	390,000	O/E/TR	Brackish	North Central
F370	1,328	206,000	R (Large)	Fresh	Northeast
F541	849	562,400	GL	Fresh	Pacific
F462	2,240	1,012,000	L	Fresh	Northeast
F495	615	264,000	R (Large)	Fresh	Midwest
F200	250	124,275	R (Small)	Fresh	Southeast
F227	566	305,556	O/E/TR	Saline	Southeast
F538	1,642	552,000	R (Large)	Fresh	Southeast
F206	487	274,000	R (Small)	Fresh	North Central
F161	212	80,666	R (Large)	Fresh	Southeast
F397	645	257,184	R (Large)	Fresh	Mid Atlantic
F537	804	550,000	O/E/TR (Small)	Brackish	Southeast
F387	870	117,600	R (Small)	Fresh	Midwest
F437	1,200	800,000	R (Large)	Fresh	Southeast
F433	1,740	786,200	O/E/TR	Brackish	Mid Atlantic
F117	70	49,025	L	Fresh	Southeast
F255	604	356,687	O/E/TR	Brackish	South Central
F535	1,328	545,486	O/E/TR (Small)	Brackish	Pacific
F484	637	261,000	R (Large)	Fresh	Pacific
F187	140	108,000	L	Fresh	North Central
F353	289	187,000	R (Small)	Fresh	Pacific
F461	1,306	996,000	R (Large)	Fresh	Northeast
F157	117	76,850	L	Fresh	Pacific
F153	165	75,000	R (Small)	Fresh	Pacific
F228	690	305,556	O/E/TR	Brackish	Mid Atlantic
F277	584	382,000	R (Small)	Fresh	North Central
F496	150	108,000	O/E/TR (Small)	Brackish	North Central
F393	380	249,000	R (Small)	Fresh	Midwest
F407	900	638,000	O/E/TR	Saline	Southeast

Fossil Facilities					
Plant ID	Plant Capacity	Circulating Water Flow	Source Water		Location
	MW	GPM	Water Type	Salinity	Region
F391	508	247,820	O/E/TR	Brackish	Mid Atlantic
F460	1,189	988,890	R (Small)	Fresh	Midwest
F226	341	304,167	R (Small)	Fresh	Midwest
F545	650	588,000	O/E/TR	Saline	Pacific
F516	630	495,000	R (Large)	Fresh	Mid Atlantic
F210	426	280,000	R (Large)	Fresh	Mid Atlantic
F241	1,182	320,016	Reservoir	Fresh	Midwest
F300	500	443,900	L	Fresh	South Central
F343	479	180,000	R (Small)	Fresh	Southeast
F438	1,085	810,000	R (Large)	Fresh	Midwest
F346	384	180,600	O/E/TR	Brackish	Southeast
F394	312	255,554	O/E/TR	Brackish	Southeast
F383	656	229,167	R (Large)	Fresh	North Central
F175	286	93,200	Reservoir	Fresh	South Central
F247	1,251	325,000	R (Large)	Fresh	South Central
F344	168	180,000	O/E/TR	Brackish	Northeast
F341	430	176,389	O/E/TR	Saline	Pacific
F463	2,090	1,015,972	L	Fresh	Mid Atlantic
F136	167	63,200	R (Small)	Fresh	Southeast
F193	115	115,000	O/E/TR	Brackish	Southeast
F510	648	480,000	O/E/TR (Small)	Brackish	Northeast
F248	1,139	336,000	Reservoir	Fresh	Midwest
F323	353	155,700	R (Large)	Fresh	Northeast
F330	419	161,638	R (Large)	Fresh	Midwest
F267	700	368,000	L	Fresh	North Central
F197	125	120,000	R (Small)	Fresh	Southeast
F481	3,135	1,396,000	GL and R	Fresh	North Central
F379	516	218,400	O/E/TR (Small)	Brackish	Northeast
F127	58	55,750	R (Large)	Fresh	Mid Atlantic
F237	600	314,800	O/E/TR	Saline	Pacific
F445	1,899	850,000	O/E/TR	Saline	Pacific
F521	810	501,050	L	Fresh	South Central
F440	1,693	822,000	L	Fresh	Mid Atlantic
F549	840	600,000	R (Small)	Fresh	Midwest
F497	348	176,000	R (Small)	Fresh	Northeast
F213	466	280,382	O/E/TR	Brackish	Northeast
F550	1,200	600,000	R (Large)	Fresh	Midwest
F211	266	280,000	R (Small)	Fresh	Midwest

Fossil Facilities					
Plant ID	Plant Capacity	Circulating Water Flow	Source Water		Location
	MW	GPM	Water Type	Salinity	Region
F278	1,918	385,231	R (Large)	Fresh	South Central
F502	1,159	449,974	O/E/TR (Small)	Brackish	Southeast
F483	2,493	1,492,000	GL	Fresh	North Central
F509	1,516	475,694	O/E/TR	Saline	Pacific
F434	1,740	786,200	GL	Fresh	Northeast
F421	1,050	721,000	R (Large)	Fresh	Mid Atlantic
F146	100	70,000	R (Small)	Fresh	Midwest
F273	700	378,000	Reservoir	Fresh	South Central
F408	506	642,000	O/E/TR	Brackish	Pacific
F449	1,254	870,000	O/E/TR	Brackish	Southeast
F523	1,266	508,000	GL	Fresh	North Central
F378	427	218,000	R (Small)	Fresh	Northeast
F324	313	155,296	O/E/TR (Small)	Brackish	Mid Atlantic
F327	207	156,944	O/E/TR	Brackish	Pacific
F399	570	257,198	GL	Fresh	North Central
F326	416	156,350	R (Large)	Fresh	Midwest
F401	1,310	618,750	O/E/TR	Saline	Pacific
F305	213	130,000	R (Large)	Fresh	Midwest
F217	470	288,000	L	Fresh	Mid Atlantic
F281	665	392,000	O/E/TR	Brackish	Southeast
F238	919	315,058	R (Large)	Fresh	Southeast
F540	2,167	560,500	L	Fresh	South Central
F252	838	343,750	O/E/TR	Saline	Pacific
F314	228	144,000	R (Small)	Fresh	Northeast
F272	428	376,112	O/E/TR	Brackish	Northeast
F505	626	455,200	R (Large)	Fresh	Northeast
F258	696	359,136	O/E/TR	Saline	Pacific
F524	861	514,000	O/E/TR	Brackish	South Central
F429	1,417	771,790	GL	Fresh	North Central
F181	202	100,000	R (Largel)	Fresh	North Central
F294	1,711	430,878	GL	Fresh	Midwest
F190	224	110,000	R (Small)	Fresh	South Central
F347	217	181,000	R (Small)	Fresh	Southeast
F177	110	94,500	L	Fresh	North Central
F303	225	127,998	GL	Fresh	North Central
F424	995	740,000	R (Large)	Fresh	Midwest
F417	1,197	696,000	L	Fresh	Midwest
F126	75	55,000	R (Small)	Fresh	Midwest

Fossil Facilities					
Plant ID	Plant Capacity	Circulating Water Flow	Source Water		Location
	MW	GPM	Water Type	Salinity	Region
F306	223	132,000	R (Small)	Fresh	Southeast
F403	1,115	620,833	L	Fresh	South Central
F454	2,219	939,628	R (Large)	Fresh	Midwest
F221	397	298,839	O/E/TR	Saline	Pacific
F525	1,222	514,837	R (Large)	Fresh	Midwest
F293	912	429,000	R (Large)	Fresh	South Central
F546	976	588,067	GL	Fresh	Midwest
F442	1,674	846,000	Reservoir	Fresh	South Central
F270	888	374,000	Reservoir	Fresh	South Central
F451	1,300	900,000	GL	Fresh	Midwest
F268	605	370,500	Reservoir	Fresh	Southeast
F418	2,045	696,000	R (Large)	Fresh	South Central
F348	837	182,636	O/E/TR	Brackish	Northeast
F456	1,230	960,000	O/E/TR	Brackish	Mid Atlantic

D
RETROFIT ESTIMATING WORKSHEET & INSTRUCTIONS

Retrofit Estimating Worksheet

EPRI, in collaboration with a number of participating utilities, is assembling information to develop an estimate of the costs to the industry associated with widespread retrofit of power plant cooling systems from once-through cooling to closed-cycle cooling. The aim of this effort is to obtain information from as many plants as possible, currently equipped with once-through cooling, and from this sample to extrapolate to a national estimate of closed-cycle cooling retrofit costs.

To expedite the collection of information from the plants, a simplified methodology has been developed which is to be provided to each plant in the form of an Excel spreadsheet for organizing the required information and making basic calculations necessary to estimate the capital and operating costs associated with a cooling system retrofit. A set of instructions accompanies the spreadsheet.

A few general comments intended to clarify the approach and request follow:

Approach

1. The cost estimates which results from this methodology are in no sense a substitute for site-specific engineering budget estimates.
2. The capital cost estimates are developed in two steps:
   - Step 1: Three separate cost number are calculated for each unit based solely on the circulating cooling water flow rate of the existing once-through cooling system. These three costs are considered to be representative of an “Easy” (lowest cost), “Average” (intermediate cost) or “Difficult” (highest cost) retrofit. The costs per gpm of circulating cooling water flow rate for each category were determined in a survey of more detailed retrofit cost estimates from 50 plants. The methodology and results of this survey are described in detail in Reference 1.
   - Step 2: A wide range of site, plant and neighborhood characteristics are identified and examined for the purpose of making a qualitative judgment as to where in the range of “Easy” to “Difficult” the particular unit would be expected to fall.

3. In addition to the project capital cost of the retrofit, there are other costs to be considered. These include

   i. Higher cooling system operating costs

   ii. Higher maintenance costs

   iii. Plant performance penalty costs.

   The estimates of these costs are provided in the spreadsheet based on general guidance or rules-of-thumb for cooling tower size, typical performance and power requirements as well as local meteorological conditions and expected power plant operating profiles.

4. Capital and operating costs are aggregated on a common basis by amortizing the capital costs for mid-range economic assumptions and remaining plant life.

Request for information

Using the attached instructions and spreadsheet, please provide the following information.

- Fill out Worksheet 1, 2 and 3 completely
- Review Worksheets….. to ensure that all the relevant "automatic" calculations have filled in and to determine whether the default values given on the worksheets seem appropriate for your plant. Adjust the default values as seems appropriate.
- Review all the qualitative information requests in Worksheets……. Add descriptive comments and identifiers as appropriate.
- Provide all drawings, maps, regulatory information as requested in the Instructions for each Worksheet.
- Provide in tabular form
  - Plant operating profiles (Worksheet 13)
  - Source water temperature (Worksheet 11)
  - Ambient temperature and wet-bulb data (Worksheet 11)

  in as much detail as possible.

The Spreadsheet worksheets are set up for a maximum of 10 units per plant which should be adequate for nearly all cases. If a plant has more than 10 units, two separate spreadsheets can be used.

Please return the completed worksheets and the requested supporting documents by

September 30, 2007

To

Maulbetsch Consulting
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Menlo Park, California 94025
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maulbets@sbcglobal.net

The following material contains explanations and instructions for the use of the accompanying Excel spreadsheets to determine the costs of closed-cycle wet cooling system retrofits.

Comprehensive retrofit cost estimates must include:

- Initial capital cost of the retrofit itself
- Additional operating power costs
- Additional O&M costs
- Plant performance penalty costs
- Assorted additional miscellaneous costs

The accompanying Excel file {Retrofit_Cost_Analyses.xls} contains 14 worksheets for compiling and organizing the required information and for executing many of the required calculations for developing a cost estimate.

Descriptions of the individual worksheets and instructions for filling them out are provided below.

Worksheet 1: Plant Information

Worksheet 1 asks for general location and contact information for the plant and is essentially self-explanatory.

- The contact person should be someone capable of answering (or of identifying other staff capable of answering) a broad range of questions about turbine and cooling system design and operation, plant site layout and constraints and pertinent environmental constraints at the site.
- The plant inlet water flow should reflect the maximum water intake to the plant for all purposes. It must be entered in units of "gallons per minute" (gpm). If it is normally available in other units, common conversions are
  - 1 mgd (million gallons per day) = 694.4 gpm
  - 1 cfs (cubic feet per second) = 448.4 gpm

Worksheet 2: Unit Information

Worksheet 2 asks for unit-specific information for each unit at the plant. There is the possibility for confusion in the case of combined-cycle plants since some companies designate the combustion turbine and steam turbine portions of combined-cycle plants with different unit numbers while others assign a single unit number to the entire combined-cycle unit.

For the case of simple cycle combustion turbine units, only information under "All unit types" is required. For combined-cycle units, the gross capacity of the steam turbine is desired in addition to the total (CT's + steam turbine) capacity. The condenser cooling water flow refers to the steam condenser cooling water flow only.

PLANT INFORMATION	
Plant Name	
Owner(s)	
Operating Company	
Location	
Street	
City	
State	
Zip Code	
Latitude	
Longitude	
Elevation	
Contact person	
Name	
Title	
Phone	
E-mail	
Plant Capacity, net (MW)	
Plant Water Intake	
Flow, gpm	

Worksheet 1: Plant Information

UNIT INFORMATION										
Unit	1	2	3	4	5	6	7	8	9	10
Unit Type [(1)]										
For all unit types										
Unit Capacity, gross (MW)										
Fuel										
Year on line										
Capacity factor, %										
2006										
2002 - 2006 Average										
For steam units										
Condenser cooling water										
Flow, gpm										
For combined cycle units										
Steam turbine capacity, gross (MW)										
Condenser cooling water										
Flow, gpm										

(1) Unit type: CT (Combustion turbine); S (Steam cycle); CC (Combined-cycle)

Worksheet 2: Unit Information

Worksheet 3: Capital Cost Information

Worksheet 3 calculates a range of initial retrofit capital costs based on the results of a survey of 50 plants conducted by Maulbetsch Consulting in 2002. The only input required is the condenser circulating water flow rate for each unit. The spreadsheet will return three costs for each unit classified as "Easy", "Average" or "Difficult" retrofits.

The judgment as to which category best describes the situation at the individual plant and unit will be based on qualitative, descriptive information as requested in subsequent worksheets. These are:

- Worksheet 4: Tower size
- Worksheet 5: Site characteristics
- Worksheet 6: Drift calculations
- Worksheet 7: Neighborhood characteristics
- Worksheet 8: Alternative water sources.

Retrofit Project Cost Estimates

Enter data

Automatic calculation

Plant: 0

Circulating Water Flow Rates

Unit No.	Circulating Water Flow (gpm)
1	0
2	0
3	0
4	0
5	0
6	0
7	0
8	0
9	0
10	0

Range of Retrofit Cost Estimates

Unit No.	Degree of Difficulty		
	Easy	Average	Difficult
1	$0	$0	$0
2	$0	$0	$0
3	$0	$0	$0
4	$0	$0	$0
5	$0	$0	$0
6	$0	$0	$0
7	$0	$0	$0
8	$0	$0	$0
9	$0	$0	$0
10	$0	$0	$0
Plant Total	$0	$0	$0

Worksheet 3: Range of retrofit costs

Worksheet 4: Tower size

Worksheet 4 returns the tower size as number of cells and the length and width of the tower footprint as a function of circulating water flow rate and a number of default assumptions listed on the worksheet. These are:

- Flow rate per cell: 10,000 gpm
- Cell dimensions: 50’ x 50’
- Basin dimensions: Extends 4’ beyond tower in all directions

These default values may be changed to accommodate individual design preferences.

The primary arrangement is in-line. The number of cells is rounded up to the nearest integer.

Back-to-back tower arrangements may be considered if the in-line arrangement is too long to be sited any where on the plant property. The worksheet also returns dimensions for back-to-back arrangements. In this case, if the number of cells calculated for the in-line tower is odd, it is increased by +1 to have an even number of cells.

Note that back-to-back towers are built somewhat taller in order to provide the necessary air inlet area which is now limited to one side of the cell. This will affect the additional pumping power for a given recirculating water flow as the head rise to the hot water distribution deck is increased. (See Worksheet 9)

Worksheet 5: Site characteristics---judging degree of difficulty

The approach to a closed-cycle retrofit used in this analysis is the following:

- The existing once-through cooling system equipment is left intact to the extent possible; that is, the condenser, the circulating water pumps and the piping connections to the condenser inlet and exit waterboxes are kept the same.
- Hot water leaving the condenser is diverted away from the existing discharge structure and is discharged into a sump.
- The sump serves as the inlet bay for new circulating water pumps which pump the hot water through new circulating water line to the hot water distribution deck on top of the cooling tower.
- Cold water from the tower basin drains by gravity through a new circulating water line back to the intake bay of the existing once-through cooling water pumps.
- Provisions must be made for bringing make-up water to the closed cycle system and for discharging blowdown from the system. In some instances, these may be easily integrated into the existing once-through cooling intake and discharge structures. In others, new structures of the appropriate size and new transport lines may be required.

A number of factors determine the degree of difficulty and hence the cost. Worksheet 5 (Site characteristics) identifies the some of the items and the information needed to assess the difficulty and provides a place to document the conclusions.

1. Tower location….An examination of the site plan determines if open areas of sufficient size are available to locate the tower on the plant property.
   a. Adjacent property may be purchasable
   b. Existing structures may have to be torn down and relocated, such as storage sheds, parking garages and parking lots, equipment shelters, office buildings, etc.
   c. Locations with tall structures upwind from the tower are not desirable since they may create downdrafts or slow distortions which impair tower performance.
2. Tower elevation…The tower should be sited at a higher elevation than the existing cooling system intake bay in order to allow gravity return of the cold water. If this is not possible, grading may be required to elevate the tower basin. Absent this, a second set of new circulating water pumps to return the cold water may be required.
3. Interferences
   a. Underground interferences in the path of the new circulating water lines or at the location of the hot water sump and new circulating water pumps may add greatly to the time and cost of the installation.
   b. Overhead interferences include transmissions lines. The moist plume and drift from the fan stacks of mechanical draft towers should not impinge on transmission lines or plant switchgear.
4. Excluded areas….There may be areas on the site reserved for security purposes, storage of hazardous materials, turn-around areas for large vehicles, etc. which cannot be relocated or blocked. This may be particularly true for nuclear facilities.

Tie-ins to existing cooling system

5. Existing intake/discharge structures are sized for the full recirculating flow rate which is much greater (10 to 50 times) than the make-up and blowdown flows from a closed-cycle system of the same cooling capacity. They may need to be abandoned and replaced with properly sized facilities. In some cases, they can be partially blocked to accommodate the lower flows.
6. Details of cooling water system circuitry around the condenser are highly variable. The general arrangement drawings must be examined with the idea of determining how to bring cold water to the pump inlets and diverting condenser discharge to a newly constructed intake sump for the new circulating water pumps. The amount of space available, the arrangement of existing piping and surrounding structural walls will all affect the effort and cost required to convert this portion of the system to closed cycle.
7. The new circulating water pumps must be located close to the existing condenser discharge area and power must be provided. If there are insufficient on-site auxiliary power facilities, they must be provided at additional time, cost and space requirements.

8. A sump must be provided as an intake bay for the new circulating water pumps. The sump must be large enough to provide adequate storage time for the circulating water flow (typically several hundred thousand gallons per minute). Finding adequate space for the sump may be difficult at many plants.

Site soil conditions

9. Unfavorable soil conditions can add substantially to the cost of the retrofit. Saturated soils may require extensive drainage, pumping and the installation of liners to allow installation of the circulating water lines, sumps and tower basin. Pilings may be required to support heavy structures on unstable soils.
10. Conversely, bedrock close to the surface may require blasting and excavation in order to place the lines.
11. On some sites, previous usage and spillage may have resulted in contaminated soil which, if disturbed, becomes subject to costly clean-up or disposal requirements.

It is difficult to provide rigorous guidance on how the consideration of each of these items is translated into the categorization of the project as “easy”, “average” or ”difficult”. However, if none of the items presents any obvious problems, an “easy” retrofit might be expected. If two or three do, “average” is probably appropriate. If more, then “difficult” is appropriate.

Retrofit Project Tower Size Estimates

Enter data

Automatic calculation

Assumptions:

Flow rate per cell, gpm:
Cell length, ft.:
Cell width, ft.:
Basin extends 4 ft. beyond

Plant: 0

Do not erase

Circulating Water Flow Rate Information

Unit No.	Circulating Water Flow (gpm)
1	0
2	0
3	0
4	0
5	0
6	0
7	0
8	0
9	0
10	0

Tower Size---In-line arrangement

Unit No.	# of cells (-)	Length Ft.	Width Ft.	Area Sq. Ft.
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				

Tower Size---Back-to-back arrangement

Unit No.	# of cells (-)	Length Ft.	Width Ft.	Area Sq. Ft.
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				

Worksheet 4: Tower size calculations

COOLING SYSTEM RETROFIT ANALYSIS

Plant: 0

ADDITIONAL SITE INFORMATION---To determine difficulty of installation		
Site description	Drawings Available	Descriptive Notes
Plant site boundaries		
Existing structures		
Type		
Location		
Ground elevation profiles		
Underground utilities		
Type		
Location		
Depth		
Areas excluded from consideration as cooling tower location		
Existing cooling system		
Schematics/general arrangement drawings		
Intake/discharge structures		
Condenser inlet/exit piping		
Circulating water pumps		
Site geology		
Saturated or unstable soils		
Areas requiring rock excavation		
Contaminated soil areas		

Worksheet 5: Site characteristics

Plume and drift considerations

Cooling towers frequently emit visible plumes during periods of cold weather and all towers emit some quantity of drift at all times. The implications of the frequent presence of a visible plume and the continuous emission of drift on the cost of and the ability to license a cooling tower retrofit depends strongly on the characteristics of the neighborhood surrounding the plant.

Worksheet 6 (Neighborhood characteristics)

This Worksheet identifies characteristics of the neighborhood in the vicinity of the plant and organizes items to consider in determining the likelihood that drift or visible plume would raise serious objections to the siting of a cooling tower on the site.

Visible plumes…..Visible plumes can be a problem for safety or aesthetic reasons. Safety issues arise if the plume obscures visibility on roadways or at airports. Aesthetic issues can be judged to be a problem in scenic areas or in residential areas where residents object.

Objections to visible plumes can be eliminated through the specification of plume abatement towers. However, plume abatement towers can be far more expensive than conventional towers (a factor of x2 to x3 is likely) and require more fan and pumping power.

Drift….Most modern cooling towers are equipped with drift eliminators which are specified to limit drift to 0.0005% of the circulating water flow. Two problems may arise. From a regulatory perspective, the dissolved and suspended solids in the drift (TDS and TSS) can be categorized as PM_{10}. In some areas, this may be unacceptable or may require that offsets be purchased. The costs of offsets can be very high or simply unavailable in some regions.

From an environmental effects perspective, drift, particularly if it is high salinity as may be the case for saline or brackish water make-up or for towers operating at very high cycles of concentration, may cause problems both on-site and off-site. On-site problems are normally corrosion of downwind equipment and structures requiring high levels of continuing maintenance or sometimes premature replacement of equipment. Off-site problems are normally related to damage to vegetation, marring of finishes on automobiles or other impacts in residential areas.

Worksheet 7 (Drift calculations)

This Worksheet returns the total drift rate and the associated PM_{10} emissions rate for a specified circulating water flow rate and assumed values of drift eliminator efficiency, source water TDS and cycles of concentration. The PM_{10} emissions rate is determined assuming that all the dissolved solids in the drift are classified as PM_{10}. While this is widely acknowledged to be a very conservative assumption, it is nonetheless the position taken by USEPA in their emissions rule. The cost associated with offsetting the PM_{10} emissions, if this would be required, must be determined from local information on the limits of emissions and the availability and cost of offsets. There is essentially no way of reducing the drift rates below the level of 0.0005% of the circulating water flow rate with current technologies.

While there is little evidence in the literature suggesting that off-site drift damage has ever been a serious problem at tested sites, it is likely that attention to drift in siting hearings would lead to extended and costly objections which may or may not be eventually overcome.

NEIGHBORHOOD CHARACTERISTICS					
	Rural/ remote	High density/ urban	Commercial	Residential	Other
General character of neighborhood (1)					
Descriptive notes					

(1) Check all that apply

NEIGHBORHOOD FEATURES/FACILITIES		
Type	Distance from plant, miles	Name, Identifier or Description
Residential neighborhood		
High traffic roadway		
Airport		
Schools		
Retirement community		
Hospitals		
Places of worship		
Scenic areas		
Coastline		
National Park		
Other		

Worksheet 6: Neighborhood characteristics

Retrofit Project Cost Estimates

	Enter data
	Automatic calculation

Plant: 0

DRIFT CALCULATIONS			
Unit No.	Circulating Water Flow (gpm)	Drift Rate gpm	PM 10 tons/year
1	0		
2	0		
3	0		
4	0		
5	0		
6	0		
7	0		
8	0		
9	0		
10	0		

Assumptions:

Drift eliminator efficiency	0.0005%
Source water TDS	500
Cycles of concentration	5

Worksheet 7: Drift calculations

Worksheet 8: Alternative water sources

The normal assumption is that the make-up water for the retrofitted closed-cycle cooling system will be drawn from the same water source that supplies the existing once-through cooling system. Similarly, the cooling tower blowdown is assumed to be discharged to the waterbody that the once-through cooling water was returned to. In a limited number of situations, this may not be the case.

Make-up alternatives…

For example, for coastal plants using ocean water for once-through cooling, the salinity of the drift from a cooling tower with seawater make-up may be sufficiently high that the calculated PM_{10} emissions would exceed regulatory limits and require offsets which may not be available. In that case, with no options for reducing drift rates, lower salinity make-up sources would have to be considered. Options could include reclaimed municipal waste water, groundwater, irrigation drainage, produced water, mine drainage or perhaps others.

Worksheet 8 (Alternative water sources)

This Worksheet identifies these water sources and requests information on availability, amount, water quality, distance of source from plant and some information on the neighborhood through which the supply and return lines would have to be installed and any local regulatory impediments to the use of the water.

Similarly, cooling tower blowdown may not be permitted to be discharged to the same receiving water as the once-through cooling was returned to. While this would be expected to be a rare situation, increased salinity, the presence of different water treatment chemicals or other reasons may pertain.

Such restrictions may require the installation and operation of additional water treatment processes up to and possibly including zero liquid discharge equipment and associated solids disposal. If this were the case, the costs could be comparable to those for the cooling tower itself. To determine what might be required, local aqueous discharge regulations must be reviewed and interpreted.

ALTERNATIVE WATER SOURCES					
Characteristics	Municipal reclaimed water	Groundwater	Irrigation drainage	Produced water	Mine drainage
Available to plant [1]					
Quantity available, mgd					
Water quality					
pH					
TSS, ppm					
TDS, ppm					
Other					
Distance from plant, miles					
Nature of area between source and plant					
Regulations affecting use					

(1) Check all that apply

Worksheet 8: Alternative water sources

Additional operating power costs

Additional operating power costs are those associated with the additional pumping power and fan power required for the operation of the cooling tower and the circulating water loop between the condenser and the tower. These costs are calculated in Worksheets 9 and 10.

These worksheets are automatically filled and activated by entering the circulating water flow rates for each unit in Worksheet 3.

Pumping power

The results in Worksheet 9: “Pumping power” also require information about elevation changes on the site, the sizing of the circulating water lines, the circulating water pump efficiency and the pump motor efficiency. Default values for these quantities are displayed on the Worksheet and can be changed if desired to better reflect the situation at the individual site or project designer preferences.

The pumping power calculated in Worksheet 9 is only that additional power required for the new circulating water line between the condenser and the cooling tower. It is assumed that water is delivered to the tower only when the plant is operating and that the flow rate is the same whether the unit is operating at full or part load.

The pumping power for the existing once-through cooling circuit will be similar to what it was before the retrofit. However, the operating schedule may change. At some plants, with once-through cooling, the cooling water flow rate was maintained even when the unit was off-line in order to prevent fouling or silting of the intake structure. With the closed-cycle arrangement described above, where the intake and discharge structures are modified, this would likely not be the case and some pumping power savings might be realized.

In many cases, the need for additional power for the new circulating water pumps and fans will require the installation of new on-site, electrical infrastructure such as motor control centers, transformers, switchgear, etc. If this is the case for this site, please indicate Yes or No and provide a brief description of the nature, size and any difficulties associated with locating the equipment on the spreadsheet of separately.

Fan power

The results in Worksheet 10: “Fan power” also require information about fan size and fan motor efficiency. Default values for these quantities are displayed on the Worksheet and can be changed if desired to better reflect the situation at the individual site or project designer preferences.

The calculations in Worksheet 10 assume that all fans are at full speed whenever the plant is operating. During some periods of the year, when the unit is at partial load or the ambient wet-bulb temperature is well below design, some operators turn off fans to save power with little or no effect on turbine performance. However, these operating procedures vary widely from plant to plant and are not considered in this analysis.

In many cases, the need for additional power for the new circulating water pumps and fans will require the installation of new on-site, electrical infrastructure such as motor control centers, transformers, switchgear, etc. If this is the case for this site, please indicate Yes or No and provide a brief description of the nature, size and any difficulties associated with locating the equipment on the spreadsheet of separately.

Additional maintenance costs

Closed-cycle cooling systems are likely to incur higher maintenance costs than the once-through cooling systems which they replace. This is the result of several factors:

- The cooling tower itself requires cleaning, fill and drift eliminator maintenance and, in some cases, periodic repacking of the tower.
- The retrofitted system will have additional circulating water pumps, modified intake structure, etc.
- Water treatment may be required for discharge of cooling tower blowdown. If zero liquid discharge rules pertain, the costs can equal that of the cooling tower. (This seems unlikely at a site currently on once-through cooling.)

The cost of the additional maintenance in labor, equipment and chemicals is highly site-specific. However, a range of independent studies (EPA, Burns, Burns and Micheletti) have used factored costs ranging from 1 to 3% of the cooling system capital costs. Assuming this accounts for approximately 40% of the ”EASY” estimate on Worksheet 4, an annual additional maintenance cost may be estimated. This is included in the summary cost table on Worksheet 14 using 2% as an intermediate factor.

Retrofit Project Cost Estimates

(yellow)	Enter data
(cyan)	Automatic calculation

Plant: 0

Pumping Power Calculations

Unit No.	Circulating Water Flow (gpm)	Tower Arrangement In-line = 1; Back-to-back =2	Line Dia. ft	Δh3 ft	Δh4 ft	Total Head ft	Pump Power MW
1	0						0.00
2	0						0.00
3	0						0.00
4	0						0.00
5	0						0.00
6	0						0.00
7	0						0.00
8	0						0.00
9	0						0.00
10	0						0.00

Calculations:
Pumping power = (Circ. water flow rate x Head rise)/(Pump efficiency x Motor efficiency)
Head rise = Δh1+ Δh2 + Δh3 + Δh4
Δh1 = Elevation rise from sump level to pump level
Δh2 = Elevation rise from pump to tower site
Δh3 = Height of tower hot water distribution deck
Δh4 = Head loss through circulating water line to tower

Assumptions:

Δh1, feet	5	
Δh2, feet	10	
Δh3, feet	25	for in-line arrangement
Δh3, feet	35	for back-to-back arrangmeent
Δh4, feet	Calculated assuming circ. water flow velocity	
Velocity, ft/sec	9	
Pump efficiency	0.85	
Motor efficiency	0.9	
Circ. line length, ft	1,000	

Worksheet 9: Pump power calculations

	Enter data
	Automatic calculation

Plant: 0

Fan Power Calculations		
Unit No.	**Number of cells**	**Fan Power**
		MW
1		0.0
2		0.0
3		0.0
4		0.0
5		0.0
6		0.0
7		0.0
8		0.0
9		0.0
10		0.0

Calculations: Fan power = (Number of cells x Fan power)/Motor efficiency

Assumptions:

Power per fan	200
Motor efficiency	0.9

Worksheet 10: Fan power calculations

Plant performance penalty costs

Retrofitting once-through cooled plants with closed-cycle cooling generally imposes a performance penalty on the unit, since the cold water supplied to the condenser from the cooling tower is typically at a higher temperature than water that would be withdrawn from the local natural waterbody. This is a result of the following considerations.

1. Cold water from a cooling tower is limited by the ambient wet-bulb temperature. Typical tower designs deliver cold water about 10ºF higher than wet-bulb at the "1% wet-bulb" design point.[6]
2. At times when the wet-bulb is lower as it is during colder, drier weather, the "approach" to wet-bulb is higher than 10ºF.

Therefore, the condenser inlet temperature with a closed-cycle system is nearly always higher than with a once-through cooling system, resulting in a corresponding increase in the condensing temperature and the turbine backpressure.

Increased turbine backpressure leads to a higher unit heat rate which results in either reduced MW output at a constant firing rate or a higher firing rate to maintain a constant MW output. In either case, an economic penalty is incurred either as lost revenue or increased fuel cost.

An estimate of the magnitude of the performance penalty can be carried out at varying levels of complexity.

In the absence of any additional information, an annual heat rate penalty of 1.5% to 2% is consistent with a number of independent analyses. However, the magnitude of the penalty will vary with a number of factors. The most important of these are unit operating profile, condenser and cooling tower design, turbine characteristics and site meteorology.

The following worksheets indicate the information required for a comprehensive estimate of the performance penalty.

Worksheet 11 (Site source water and ambient weather information)

This worksheet provides tables for entering information on source water temperature and ambient temperature and wet-bulb temperature in varying levels of detail. Hourly data for source water data for an entire year is preferred. However, if this level of detail is not available, an alternate table to provide maximum, average and minimum values of source water temperature for each month is provided.

[6] That wet-bulb temperature which is exceeded only 1% of the summertime (June through September) hours (~ 30 hours/year)

Worksheet 12: Condenser Design

Table A, requests condenser design information, turbine heat rate information[7] and average fuel cost and energy price information. In the absence of condenser design information, the smaller tables to the left of Table A on the Worksheet will use the indicated default values and the maximum source water temperature and the 1% wet-bulb temperature from Worksheet 11 to calculate a "design point" difference in turbine backpressure between the two cooling systems. Note that Worksheet 11 contains Table A which can accept condenser design information if available. The results calculated for the design specifications can then be manually substituted for the default values if desired.

Worksheet 13: Operating Profile

Tables 1 and 2 provide alternate levels of detail for providing the unit operating profiles.

The effect of different tower design choices can be observed by varying the approach temperature away from the default value of 10 ºF. Limits of 5 ºF (larger tower) and 15 ºF (smaller tower) are suggested.

Worksheet 14: Summary

This final Worksheet aggregates all the costs and expresses them both as an annualized and a life cost.

[7] A manufacturer-supplied heat rate curve would be preferable to these point values if available.

Plant: 0

(yellow)	Enter data
(cyan)	Automatic calculation

SITE INFORMATION	
Water Source	
Source water temperature	
Yearly maximum, F	
Yearly minimum, F	
Yearly average, F	
Ambient temperature	
Yearly maximum, F	
Yearly minimum, F	
Yearly average, F	
Ambient wet bulb	
1% wet bulb, F	
Yearly minimum, F	
Yearly average, F	

Source water temperature data	
Date/Time	Temperature, F
1/1/06 0:00	
1/1/06 1:00	
1/1/06 2:00	
1/1/06 3:00	
1/1/06 4:00	
1/1/06 5:00	
1/1/06 6:00	
1/1/06 7:00	
1/1/06 8:00	
1/1/06 9:00	
1/1/06 10:00	
1/1/06 11:00	
1/1/06 12:00	
1/1/06 13:00	
1/1/06 14:00	
1/1/06 15:00	
1/1/06 16:00	
1/1/06 17:00	
1/1/06 18:00	
1/1/06 19:00	
1/1/06 20:00	
1/1/06 21:00	
1/1/06 22:00	
1/1/06 23:00	
1/2/06 0:00	

extend for full year

Ambient temperature data			
Month	Maximum, F	Average, F	Minimum, F
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			
Annual	0	#DIV/0!	0

Wet bulb temperature data			
Month	Maximum, F	Average, F	Minimum, F
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			
Annual	72	#DIV/0!	0

Worksheet 11: Site source water and ambient temperature data

Plant:	0

(yellow)	Enter data
(cyan)	Automatic calculation

Once-through cooling (based on Default values below)	
Max. source water temperature, F	0
Steam condensing temperature, F	27
Turbine backpressure, in Hga	0.3

Once-through cooling (based on Default values below)	
1% wet bulb temperature, F	0
Steam condensing temperature, F	37
Turbine backpressure, in Hga	0.3

Default values	
Condenser design assumptions	
Range, F	20
TTD, F	7
Cooling tower design assumptions	
Approach, F	10

Economic factors	
Fuel cost, $/MMBtu	5
Power price, $/MWh	35

Table A---UNIT DESIGN/OPERATING INFORMATION (If available--otherw					
Unit	1	2	3	4	5
Condenser design specs.					
Cooling water flow, gpm	0	0	0	0	0
Steam flow, lb/hr					
Heat load, Btu/hr					
Water inlet temp., F					
Water exit temp., F					
Steam condensing temperature, F					
Steam condensing pressure, inHga					
Efficiency/heat rate penalties					
Output @ design backpressure					
Output @ design backpressure + 1 in Hga					
Output @ design backpressure + 2 in Hga					

Worksheet 12: Cooling system and unit design information

Unit Operating Profile Data

Preferred: Hourly power level for each unit for corresponding period as source water and ambient temperature data (See Table 1)

Minimum: Monthly energy output (MWh) for each unit for same year as source water and ambient temperature data (See Table 2)

Table 1 Hourly Power Level--By Unit

Date/Time	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5
	MW	MW	MW	MW	MW
1/1/06 0:00					
1/1/06 1:00					
1/1/06 2:00					
1/1/06 3:00					
1/1/06 4:00					
1/1/06 5:00					
1/1/06 6:00					
1/1/06 7:00					
1/1/06 8:00					
1/1/06 9:00					
1/1/06 10:00					
1/1/06 11:00					
1/1/06 12:00					
1/1/06 13:00					
1/1/06 14:00					
1/1/06 15:00					
1/1/06 16:00					
1/1/06 17:00					
1/1/06 18:00					
1/1/06 19:00					
1/1/06 20:00					
1/1/06 21:00					
1/1/06 22:00					
1/1/06 23:00					
1/2/06 0:00					

extend for full year

Worksheet 13: Unit operating profile; (Table 1---preferred)

Table 2 Monthly Energy Output--By Unit					
Month	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5
	MWh	MWh	MWh	MWh	MWh
January					
February					
March					
April					
May					
June					
July					
August					
September					
October					
November					
December					

add'l units

Worksheet 13: Unit operating profile; (Table 2---minimum)

SUMMARY INFORMATION														
Unit No.	Capital Cost			Operating Power		Maintenance	Heat rate penalty	Annualized Cost			Present Value--Life Cost		
	$	$	$	MW	$/yr	$/yr	$/yr	$	$	$	$	$	$
	Easy	Average	Difficult					Easy	Average	Difficult	Easy	Average	Difficult
1	$0	$0	$0	0.00	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	$0	$0	$0	0.00	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	$0	$0	$0	0.00	$0	$0	$0	$0	$0	$0	$0	$0	$0
4	$0	$0	$0	0.00	$0	$0	$0	$0	$0	$0	$0	$0	$0
5	$0	$0	$0	0.00	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	$0	$0	$0	0.00	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	$0	$0	$0	0.00	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	$0	$0	$0	0.00	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	$0	$0	$0	0.00	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	$0	$0	$0	0.00	$0	$0	$0	$0	$0	$0	$0	$0	$0

Worksheet 14: Summary

E

PLANTS SELECTED FOR DEGREE OF DIFFICULTY COST ESTIMATES

Nuclear Facilities					
Plant ID	Plant Capacity	Circulating Water Flow	Source Water		Location
	MW	GPM	Water Type	Salinity	Region
N513	700	514,100	L	Fresh	Southeast
N218	2540	1,763,889	O/E/TR (Small)	Brackish	Northeast
N486	595	404,188	GL	Fresh	North Central
N419	1,365	700,000	GL	Fresh	North Central
N269	581	372,000	GL	Fresh	Northeast
N233	1,296	900,000	O/E/TR	Saline	Northeast
N302	2,150	1,621,528	O/E/TR	Saline	Pacific
N178	1,956	1,880,000	L	Fresh	Mid- Atlantic
N459	1,700	974,600	O/E/TR	Saline	Southeast
N321	2,298	1,736,000	O/E/TR	Saline	Pacific

Fossil Facilities					
Plant ID	Plant Capacity	Circulating Water Flow	Source Water		Location
	MW	GPM	Water Type	Salinity	Region
F439	1,950	820,139	O/E/TR	Saline	Pacific
FOS1	292	154,000	River	Fresh	Mid Atlantic
F271	605	375,000	R (Large)	Fresh	North Central
F338	256	175,000	GL	Fresh	Midwest
F380	837	219,600	L	Fresh	Mid Atlantic
F296	766	434,000	GL	Fresh	Midwest
F251	586	340402	GL	Fresh	Midwest
F541	849	562,500	GL	Fresh	Midwest
F495	615	264,000	R (Large)	Fresh	South Central
F200	250	124,275	R (Small)	Fresh	Mid Atlantic
F538	1,642	552,000	R (Large)	Fresh	Northeast
F387	870	117,600	R (Small)	Fresh	Mid Atlantic
F437	1,200	800,000	R (Large)	Fresh	Midwest
F433	1,740	786,200	O/E/TR	Brackish	South Central
F117	70	49,025	L	Fresh	Midwest
F535	1,328	545,486	O/E/TR (Small)	Brackish	Mid Atlantic
F484	637	261,000	R (Large)	Fresh	Northeast
F187	140	108,000	L	Fresh	North Central
F228	690	305,556	O/E/TR	Saline	Pacific
F277	584	382,000	R (Small)	Fresh	Midwest
F393	380	249,000	R (Small)	Fresh	Northeast
F318	237	148,000	O/E/TR	Saline	Southeast
F390	388	245,139	River	Fresh	Midwest
F160	180	80,800	R (Small)	Fresh	Southeast
F283	586	400,000	GL	Fresh	Northeast
F436	1,594	795,833	GL	Fresh	Midwest
F465	1,570	1,020,000	R (Small)	Fresh	Northeast
F204	941	264,800	O/E/TR	Saline	Pacific
F119	195	57,639	R (Large)	Fresh	North Central
F547	958	595,139	O/E/TR	Saline	Pacific
F122	60	54,000	O/E/TR (Small)	Brackish	Northeast
F382	348	224,306	R (Small)	Fresh	Midwest
F339	360	175,000	R (Large)	Fresh	North Central
F345	750	180,866	R (Large)	Fresh	Southeast
F198	231	123,000	R (Small)	Fresh	Midwest
F170	185	87,450	L	Fresh	Southeast
F275	800	380,500	R (Small)	Fresh	Southeast
F155	75	75,000	O/E/TR	Saline	Pacific
F172	103	90,000	GL	Fresh	North Central
F420	1,279	704,167	O/E/TR	Saline	Pacific

Fossil Facilities					
Plant ID	Plant Capacity	Circulating Water Flow	Source Water		Location
	MW	GPM	Water Type	Salinity	Region
F332	124	163,826	GL	Fresh	North Central
F485	103	127,778	O/E/TR	Saline	Pacific
F402	983	620,000	O/E/TR (Small)	Brackish	Northeast
F256	880	356,944	O/E/TR	Saline	Pacific
F391	508	247,820	O/E/TR	Brackish	Southeast
F226	341	304,167	R (Small)	Fresh	Midwest
F545	650	588,194	O/E/TR	Saline	Pacific
F516	630	495,000	R (Large)	Fresh	Mid Atlantic
F210	426	280,000	R (Large)	Fresh	Mid Atlantic
F124	67	54,167	River	Fresh	Northeast
F300	500	443,900	L	Fresh	South Central
F438	1,085	810,000	R (Large)	Fresh	Midwest
F337	256	170,646	GL	Fresh	Midwest
F346	384	180,600	O/E/TR	Saline	Southeast
F383	656	229,167	R (Large)	Fresh	North Central
F175	286	93,200	Reservoir	Fresh	South Central
F341	430	176,389	O/E/TR	Fresh	Pacific
F463	2,090	1,015,972	L	Fresh	Mid Atlantic
F136	167	63,200	R (Small)	Fresh	Southeast
F193	115	115,000	O/E/TR	Brackish	Southeast
F510	648	480,000	O/E/TR (Small)	Brackish	Northeast
F323	353	155,700	R (Large)	Fresh	Northeast
F330	419	161,638	R (Large)	Fresh	Midwest
F267	700	368,000	L	Fresh	North Central
F197	125	120,000	R (Small)	Fresh	Southeast
F481	3,135	1,396,000	GL and R	Fresh	North Central
F379	516	218,400	O/E/TR (Small)	Brackish	Northeast
F447	1,248	857,000	O/E/TR (Small)	Saline	Mid Atlantic
F237	600	314,800	O/E/TR	Saline	Pacific
F445	1,899	850,000	O/E/TR	Saline	Pacific
F440	1,693	822,000	L	Fresh	Mid Atlantic
F549	840	600,000	R (Small)	Fresh	Midwest
FOS2	245	144,000	River	Fresh	Midwest
F497	348	176,000	R (Small)	Fresh	Northeast
F550	1,200	600,000	R (Large)	Fresh	Midwest
F211	266	280,000	R (Small)	Fresh	Midwest
F483	2,493	1,492,000	GL	Fresh	North Central
F509	1,516	475,694	O/E/TR	Saline	Pacific
F434	1,740	786,200	GL	Fresh	Northeast
F421	1,050	721,000	R (Large)	Fresh	Mid Atlantic
F146	100	70,000	R (Small)	Fresh	Midwest
F273	700	378,000	Reservoir	Fresh	South Central

Fossil Facilities					
Plant ID	Plant Capacity	Circulating Water Flow	Source Water		Location
	MW	GPM	Water Type	Salinity	Region
F408	506	642,000	O/E/TR	Brackish	Pacific
F449	1,254	870,000	O/E/TR	Saline	Southeast
F378	427	218,000	R (Small)	Fresh	Northeast
F235	510	312,500	O/E/TR	Brackish	Mid Atlantic
F327	207	156,944	O/E/TR	Saline	Pacific
F326	416	156,250	R (Large)	Fresh	Midwest
F401	1,310	618,750	O/E/TR	Saline	Pacific
F305	213	130,000	R (Large)	Fresh	Midwest
F281	665	392,000	O/E/TR	Saline	Southeast
F540	2,167	560,500	L	Fresh	South Central
F252	838	343,750	O/E/TR	Saline	Pacific
F314	228	144,000	R (Small)	Fresh	Northeast
F272	428	376,112	O/E/TR	Brackish	Northeast
F505	626	455,200	R (Large)	Fresh	Northeast
F356	65	45,139	River	Fresh	NorthCentral
F258	696	359,136	O/E/TR	Saline	Pacific
F524	861	513,889	O/E/TR	Brackish	South Central
F429	1,417	771,790	GL	Fresh	North Central
F181	202	100,000	R (Largel)	Fresh	North Central
F347	217	181,000	R (Small)	Fresh	Southeast
F177	110	94,500	L	Fresh	North Central
F303	225	127,998	GL	Fresh	North Central
F424	995	740,000	R (Large)	Fresh	Midwest
F126	75	55,000	R (Small)	Fresh	Midwest
F306	223	132,000	R (Small)	Fresh	Southeast
F454	2,219	939,628	R (Large)	Fresh	Midwest
F480	2,726	1,390,278	L	Fresh	South Central
F221	397	298,611	O/E/TR	Saline	Pacific
F525	1,222	514,837	R (Large)	Fresh	Midwest
F293	912	429,000	R (Large)	Fresh	South Central
F546	736	508,000	River	Fresh	Midwest
F442	1,674	846,000	Reservoir	Fresh	South Central
F270	888	374,000	Reservoir	Fresh	South Central
F451	1,300	900,000	GL	Fresh	Midwest
F268	605	370,500	Reservoir	Fresh	Southeast
F348	837	182,636	O/E/TR	Saline	Northeast
FOS5	550	460,000	River	Fresh	Southeast

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