Issues Analysis of Retrofitting Once-Through Cooled Plants with Closed-Cycle Cooling

California Coastal Plants

TR-052907

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INTRODUCTION

1.1 Background

Twenty-one power plants are located on the California coast and designed to draw cooling water from the ocean or from adjoining bays, estuaries and inlets. Of these, three plants, Humboldt Bay, Hunters Point and Long Beach are retired. The remaining eighteen plants comprise 61 currently operating units. Most of the units have been in service for many years; the oldest at Redondo Beach since 1948; the newest, at Diablo Canyon since 1985. All of these units are equipped with once-through cooling systems that had been the commonly utilized system in the power industry up through the early 1970s and are still the system in use at approximately 50% of the U.S. power generating capacity.

In 1972 the Federal Water Pollution Control Act (amended in 1977 and thenceforth known as the Clean Water Act) (Environmental Protection Agency, 2002) addressed concerns over the environmental effects of once-through cooling including both the return of heated discharge to natural receiving waters and impingement and entrainment losses[1] at the cooling water intake. This resulted in regulations under Sections 316(a) {Thermal discharge} and 316(b) {Cooling Water Intakes}. Compliance with these regulations led to modified designs and operating procedures at new plants and at some existing plants using once-through cooling and a widespread, nearly universal shift to the use of recirculating cooling systems, typically mechanical- or natural-draft wet cooling towers at new plants.

In 2004, EPA issued the Final Rule on Cooling Water Intake Structures, Phase II, Large Existing Electric Generating Plants (EPA, 2004). On January 25, 2007, the 2nd Circuit Court remanded the Phase II Rule back to EPA. On July 9, 2007, EPA published an announcement in the Federal Register that the rule was suspended in its entirety.

1.2 California Activities

In 2005, two California agencies, the State Lands Commission and the Ocean Protection Council took up consideration of the environmental effects from once-through cooling on coastal waters and of possible mitigating measures. Several hearings were held and the following resolutions were issued.

[1] Entrainment refers to the drawing in of aquatic organisms into the cooling systems and subjecting them to thermal, physical or chemical stresses; impingement refers to the pinning of aquatic organisms, primarily fish, against screens or other parts of the intake structure.

By the State Land Commission…. In April, 2006 the State Lands Commission approved a resolution, "Regarding Once-Through Cooling in California Power Plants" (California State Land Commission, 2006) which stated, among other things that

"…the Commission shall not approve new leases for power facilities, or leases for re-powering existing facilities, or extensions or amendments of existing leases for existing power facilities, whose operations include once-through cooling…." followed by a series of compliance requirements.

By the Ocean Protection Council…. On April 20, 2006, the Ocean Protection Council adopted a resolution "Regarding the Use of Once-Through Technologies in Coastal Waters" (California Ocean Protection Council, 2006) which stated among other things that

"…in agreement with U.S. EPA findings, the environmental impacts from once-through cooling technologies for coastal power plants can be significant, and resolves to urge the State Water Resources Control Board to implement Section 316(b) and more stringent state requirements requiring reductions in entrainment and impingement at existing coastal power plants and encourages the State to implement the most protective controls to achieve a 90-95 percent reduction in impacts; and

"…RESOLVES to fund a 6-month study that will analyze each of the existing coastal plant's conversion to alternative cooling technologies or installation of best technology available.."

The study has since been funded with TetraTech, Inc. with the general objective "to examine each of the 21 existing coastal power plants that use once-through cooling and determine whether different cooling methods can be used or if structural or operational modifications can be made to reduce impingement and entrainment mortality".

On June 13, 2006, the State Water Resources Control Board issued a "proposed Statewide Policy on Clean Water Act Section 316(b) Regulations" (California State Water Resources Control Board, 2006) which would require, among other things, compliance with 40 C.F.R. Part 125, Subpart J revised as of July 1, 2005 and, in addition, apply the following requirements:

1. for existing power plants to reduce impingement mortality
   a. reduce intake flow to that commensurate with a closed-cycle recirculating system, or
   b. reduce the maximum through screen design intake velocity to 0.5 feet per second or less, or
   c. reduce impingement mortality for all life stages of fish and shellfish by 95 percent from the calculated baseline by any combination of operational or structural controls.
2. for existing power plants to reduce entrainment mortality
   a. reduce intake flow to that commensurate with a closed-cycle recirculating system, or
   b. if the power plant has a capacity utilization rate of 15 percent or greater, reduce entrainment of all life stages of fish and shellfish by 90 percent of the calculated baseline by any combination of operational or structural controls, or

c. if owners or operators can demonstrate that no combination of operational and structural controls can feasibly achieve the 90 percent reduction, to comply with a series of alternative requirements.

A complete discussion of all aspects of the proposed policy is given in the Scoping Document (California State Water Resources Control Board, 2006). It should be noted, however, that the formulation of the policy was based on the EPA Phase II regulation which has now been suspended following the 2nd Circuit Court remand of portions of the rule back to EPA.

1.3 EPRI/Industry Activities

In June 2006 EPRI in collaboration with an owners' group representing the coastal power plants in California, initiated a set of investigations to provide technical information to help inform once through cooling Policy development in the State. Specific project goals include:

1. documenting the preliminary costs of wet closed-cycle cooling retrofits compared to new facility installations, assessing the feasibility of dry cooling at most facilities
2. discussing the environmental impacts and other considerations associated with wet closed-cycle cooling
3. establishing a consistent basis for the specific parameters and level of detail for site-specific facility estimates for use in Comprehensive Demonstration Studies (CDS)

The following report documents the results of that study.

1.4 Organization of Report

The remainder of the report is organized as follows. Section 2 contains basic information on each of the plant sites, plants and units on the California coast. This includes their location, cooling water source, capacity, licensed cooling water flow, recent capacity factors, site meteorological information such as ocean water temperature and ambient air temperature and relative humidity and any other items necessary to carry out the assessments noted in the goals above.

Section 3 will review the methodology for identifying the preferred sizing of recirculating systems to be selected for retrofit application at California coastal plants originally designed for and operated on once-through cooling. This section will include the consideration of dry cooling retrofits based on forced-draft, air-cooled condensers as well as wet cooling towers.

Section 4 reviews the essential cost elements which must be considered in determining the cost of cooling system retrofits including capital equipment and materials costs, installation costs, O&M costs, additional power, any penalty costs resulting from decreased plant efficiency or output and costs which may be incurred due to early shutdown of units in the face of excessive economic costs of a required retrofit.

Section 5 will develop reference costs based on the installation of recirculated wet cooling systems for new facilities at "greenfield" sites. These costs will provide a solidly established point of departure from which retrofit costs can be estimated based on estimates of the "degree of difficulty" over and above what would be encountered for new construction at individual plant sites.

Section 6 will give general ranges of the magnitude of retrofit costs based on recent studies and publications and any actual retrofits that have been conducted at plants elsewhere in the U.S.

Section 7 summarizes important non-economic issues related to cooling system retrofits—issues that affect the feasibility and difficulty of retrofitting closed cycle cooling systems to existing plants in addition to higher installation and operation costs. These include considerations of business economics, energy production and efficiency, of adverse environmental effects of closed-cycle cooling including increased air emissions, drift, visible plumes, water and waste discharge and disposal, noise, aesthetics, terrestrial ecology and solid waste and of permitting and social impacts.

Section 8 provides a summary of the report and a brief statement of the important conclusions.

Two appendices to the report contain quantitative information for retrofits at the individual sites. Appendix A tabulates preliminary cost estimates for each of the California coastal plants from a 2002 report by the Stone & Webster Engineering Company. Appendix B presents discussions of the individual plants situations with the intent of categorizing the situations as "easy", "average" or "difficult" retrofits. This will provide both a generalized estimate of likely retrofit costs and give a qualitative understanding of the "non-economic" consequences at each site. It must be recognized that the cost ranges presented for each of the sites are derived from general scaling rules developed in previous studies and are not detailed engineering estimates for the sites. Qualitative discussions of site-specific characteristics are given in order to provide guidance of where in the likely range of costs each site would be expected to fall.

1.5 References

1.1 California Ocean Protection Council, 2006, http://resources.ca.gov/copc/

1.2 California State Land Commission, 2006, http://www.slc.ca.gov/

1.3 California State Water Resources Control Board, 2006, http://www.swrcb.ca.gov/npdes/cwa316.html

1.4 Environmental Protection Agency, 2002, http://www.epa.gov/r5water/cwa.htm

1.5 EPA, 2004, http://www.epa.gov/waterscience/316b/ph2.htm

2
CALIFORNIA COASTAL PLANTS

This section summarizes basic information on each of the plants and units currently operating on the California coast which are of interest to this study. Figures 2-1a and 2-1b show the approximate location of each of the plants.

(a)

Figure 2-1
California Coastal Plant Locations

(b)

Figure 2-1
California Coastal Plant Locations (Continued)

Table 2-1 lists, for each plant and unit, the unit type, the plant owner, the location, the date on-line, the unit capacity, recent capacity factor and the design inlet water flow. Table 2-2 provides meteorological and source water data for each site including the annual average values and ranges of cooling water system inlet water temperature and of ambient dry and wet bulb temperatures.

Cooling system inlet water temperatures were usually obtained from plant records. In some cases, when plant data were unavailable, estimates were made from ocean temperature records available from NOAA. [2.1] (Available at http://www.nodc.noaa.gov/dsdt/cwtg/spac.html). The average ocean temperatures for several locations along the California coast are shown in Figure 2-2. Similarly, site meteorological data, if not available from plant records, were estimated on the basis of historical (1976 to 2004) data compiled by the Air Force Office of Scientific Research (AFOSR) [2.2] for nearby locations. Figure 2-3 shows an example plot of such data for Monterey, California and Figures 2-3 and 2-4 show example data tables (also for Monterey) from which temperature ranges and temperature duration curves for the individual sites were estimated if plant data were not available.

Table 2-1
Plant/Unit Information for California Coastal Plants

Plant/Unit	Owner	Location	Type	Date On-line	Status	Capacity MW	Capacity Factor		Inlet Water Flow	
							2000 - 2006	2006	GPM	GPM/MW
ALAMITOS	AES	Long Beach				1982	20.3	9.7		
ALAMITOS 1			Steam/Gas	1956		163	6.7	3.3	72,000	442
ALAMITOS 2			Steam/Gas	1957		163	8.7	2.7	72,000	442
ALAMITOS 3			Steam/Gas	1961		333	27.7	17.1	136,000	408
ALAMITOS 4			Steam/Gas	1962		333	20.8	7.9	136,000	408
ALAMITOS 5			Steam/Gas	1969		495	27.4	9.3	202,000	408
ALAMITOS 6			Steam/Gas	1966		495	22.2	11.3	202,000	408
CONTRA COSTA	Mirant	Antioch				718	19.7	2.3		
CONTRA COSTA 6			Steam/Gas	1964		359	16.4	0.8	153,000	426
CONTRA COSTA 7			Steam/Gas	1964		359	23.1	3.8	153,000	426
DIABLO CANYON	PG&E	Near San Luis Obispo				2301	89.1	95.7		
DIABLO CANYON 1			Nuclear	1985		1137	89.0	102.9	865,278	761
DIABLO CANYON 2			Nuclear	1986		1164	89.3	88.5	865,278	743
EL SEGUNDO	NRG Energy	El Segundo				684	16.4	10.5		
EL SEGUNDO 3			Steam/Gas	1964		342	19.4	11.6	276,800	809
EL SEGUNDO 4			Steam/Gas	1965		342	24.8	9.5		
ENCINA	NRG Energy	Carlsbad				982	29.8	14.8		
ENCINA 1			Steam/Gas	1954		110	18.7	4.6	48,000	436
ENCINA 2			Steam/Gas	1956		110	21.0	9.6	48,000	436
ENCINA 3			Steam/Gas	1958		110	25.1	11.6	48,000	436
ENCINA 4			Steam/Gas	1973		306	36.0	17.9	200,000	654
ENCINA 5			Steam/Gas	1978		346	33.0	18.7	208,000	601
HARBOR	LADWP	Wilmington	Combined cycle	1994		240	14.9	5.2		
HARBOR 5						75	20.5	9.1	75,000	1000
HAYNES	LADWP	Long Beach				1279	20.7	24.7		
HAYNES 1			Steam/Gas	1962		222	26.0	29.0	96,000	432
HAYNES 2			Steam/Gas	1963		222	21.0	32.0	96,000	432
HAYNES 5			Steam/Gas	1966		341	25.0	36.0	160,000	469
HAYNES 6			Steam/Gas	1967		259	13.0	16.0	160,000	618
HAYNES 8			Combined cycle	2005		235		n/a	160,000	681
HUNTINGTON BEACH	AES	Huntington Beach				886	17.3	12.9		
HUNTINGTON BEACH 1				1958		218	31.5	20.4	84,000	385
HUNTINGTON BEACH 2				1958		218	31.0	16.7	84,000	385
HUNTINGTON BEACH 3				2002	Repowered	225	9.6	11.6	84,000	373
HUNTINGTON BEACH 4				2003	Repowered	225	8.5	10.8	84,000	373
MANDALAY	Reliant	Oxnard				436	17.1	6.3		
MANDALAY 1			Steam/Gas	1959		218	20.6	7.8	88,000	404
MANDALAY 2			Steam/Gas	1959		218	23.4	8.6	88,000	404
MORRO BAY	LS Power	Morro Bay				718	14.5	4.1		
MORRO BAY 3			Steam/Gas	1962		359	18.8	6.8	228,000	635
MORRO BAY 4			Steam/Gas	1963		359	18.8	5.6	228,000	635
MOSS LANDING	LS Power	Monterey Bay				1624	35.3	29.4		
MOSS LANDING 1			Combined cycle	2002		530	49.3	56.7	107,000	202
MOSS LANDING 2			Combined cycle	2002		530	49.7	56.6	107,000	202
MOSS LANDING 6			Steam/Gas	1967		812	19.7	6.2	298,000	367
MOSS LANDING 7			Steam/Gas	1968		812	24.2	10.8	298,000	367
ORMOND BEACH	Reliant	Oxnard				1500	17.0	3.3		
ORMOND BEACH 1			Steam/Gas	1971		750	16.3	0.2	476,000	635
ORMOND BEACH 2			Steam/Gas	1973		750	17.7	6.5	476,000	635
PITTSBURG	Mirant	Pittsburg				1352	18.4	3.7		
PITTSBURG 5			Steam/Gas	1960		326	23.7	7.4	160,500	492
PITTSBURG 6			Steam/Gas	1961		326	21.0	5.2	160,500	492
PITTSBURG 7			Steam/Gas	1972		700	23.5	1.4	Closed-cycle	
POTRERO	Mirant	San Francisco				218	23.4	17.4		
POTRERO 3			Steam/Gas	1965	RMR(1)	218	38.1	28.8	157,000	720
REDONDO BEACH	AES	Redondo Beach				1310	16.7	5.0		
REDONDO BEACH 5			Steam/Gas	1954		175	4.9	1.7	72,000	411
REDONDO BEACH 6			Steam/Gas	1957		175	5.6	1.7	72,000	411
REDONDO BEACH 7			Steam/Gas	1967		480	22.2	6.7	234,000	488
REDONDO BEACH 8			Steam/Gas	1967		480	19.6	5.6	234,000	488
SAN ONOFRE	SCE	Near San Clemente				2254	83.1	68.7		
SAN ONOFRE 2			Nuclear	1983		1127	86.8	68.4	811,000	720
SAN ONOFRE 3			Nuclear	1984		1127	79.4	69.0	811,000	720
SCATTERGOOD	LADWP	Playa Del Rey				818	22.1	21.3		
SCATTERGOOD 1			Steam/Gas	1958		179	25.0	29.0	78,000	436
SCATTERGOOD 2			Steam/Gas	1959		179	21.0	29.0	78,000	436
SCATTERGOOD 3			Steam/Gas	1974		460	23.0	21.0	188,000	409
SOUTH BAY	LS Power	San Diego				474	24.0	15.5		
SOUTH BAY1			Steam/Gas	1960	RMR(1)	136	40.5	35.2	71,500	526
SOUTH BAY2			Steam/Gas	1962	RMR(1)	136	40.8	29.7	71,500	526
SOUTH BAY3			Steam/Gas	1964	RMR(1)	202	21.6	7.0	117,000	579

(1) RMR = Reliability Must Run

Table 2-2
Meteorological Information for California Coastal Plant Sites

Plant/Unit	Location	Water Source	Source Water Temperaure			Ambient Temperature			Ambient Temperature		
			Max	Average	Min	Max	Average	Min	Max	Average	Min
ALAMITOS	Long Beach	Los Cerritos Channel/ Alamitos Bay	68	63	57	102	65	37	73	58	32
CONTRA COSTA	Antioch	San Joaquin River/ San Francisco Delta									
DIABLO CANYON	Near San Luis Obispo	Pacific Ocean									
EL SEGUNDO	El Segundo	Santa Monica Bay				110	63	27			
ENCINA	Carlsbad	Pacific Ocean/ Agua Hedionda Lagoon	76	67	58						
HAYNES	Long Beach	Long Beach Marina	68	63	57	102	65	37	73	58	32
HUNTINGTON BEACH	Huntington Beach	Pacific Ocean									
LOS ANGELES HARBOR	Wilmington	Inner LA Harbor Complex Slip 5									
MANDALAY	Oxnard	Edison Canal/ Channel Islands Harbor									
MORRO BAY	Morro Bay	Morro Bay									
MOSS LANDING	Monterey Bay	Moss Landing harbor									
ORMOND BEACH	Oxnard	Pacific Ocean									
PITTSBURG	Pittsburg	San Francisco Bay				112	62	31			
POTRERO	San Francisco	San Francisco Bay									
REDONDO BEACH	Redondo Beach	King Harbor/ Santa Monica Bay									
SAN ONOFRE	Near San Clemente	Pacific Ocean									
SCATTERGOOD	Playa Del Rey	Santa Monica Bay	68	63	57	96	65	35	70	57	30
SOUTH BAY	San Diego	San Diego Bay									

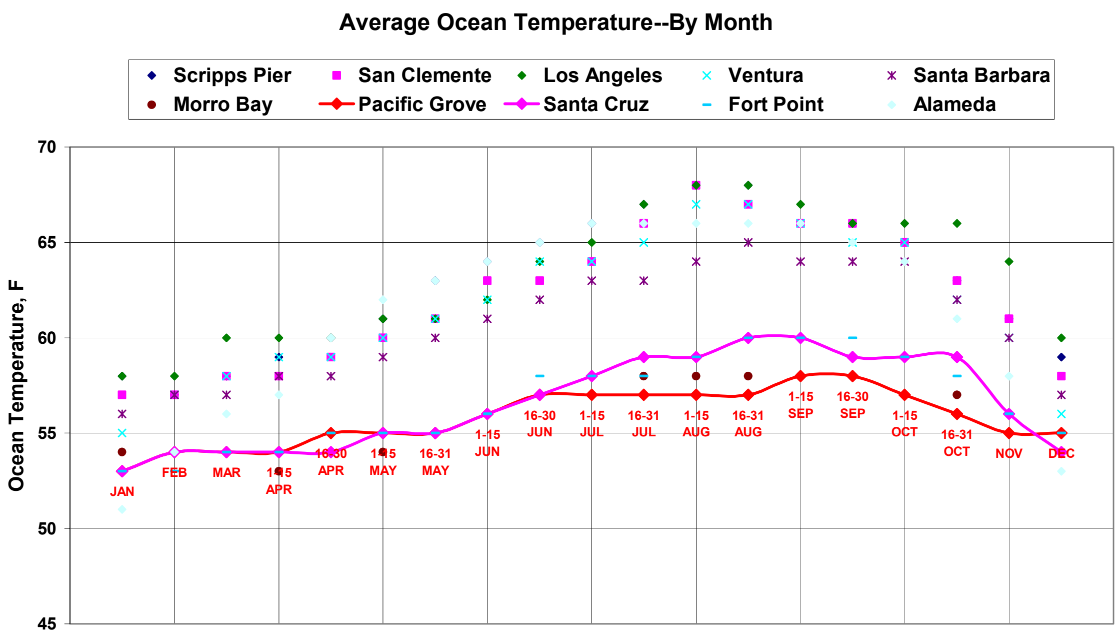


Figure 2-2
Annual Ocean Temperature Ranges for Selected Locations (from Reference 2.1)

MONTEREY CA	
Latitude = 36.58 N	WMO No. 724915
Longitude =121.80 W	Elevation = 253 feet
Period of Record = 1973 to 1996	Average Pressure = 29.75 inches Hg

Design Criteria Data

		Mean Coincident (Average) Values			
Dry Bulb Temperature (T)	**Design Value (°F)**	Wet Bulb Temperature (°F)	Humidity Ratio (gr/lb)	Wind Speed (mph)	Prevailing Direction (NSEW)
Median of Extreme Highs	90	63	45	7.7	W
0.4% Occurrence	78	61	54	7.0	NW
1.0% Occurrence	74	60	57	7.6	NW
2.0% Occurrence	72	60	59	8.1	NW
Mean Daily Range	14	-	-	-	-
97.5% Occurrence	42	39	30	5.4	ESE
99.0% Occurrence	40	37	28	5.4	ESE
99.6% Occurrence	37	34	24	5.6	ESE
Median of Extreme Lows	32	29	18	5.6	ESE
		Mean Coincident (Average) Values			
Wet Bulb Temperature (T_{wb})	**Design Value (°F)**	Dry Bulb Temperature (°F)	Humidity Ratio (gr/lb)	Wind Speed (mph)	Prevailing Direction (NSEW)
Median of Extreme Highs	68	80	81	7.4	WNW
0.4% Occurrence	64	73	73	8.1	NW
1.0% Occurrence	63	71	71	8.2	NW
2.0% Occurrence	62	70	69	8.1	NW
		Mean Coincident (Average) Values			
Humidity Ratio (HR)	**Design Value (gr/lb)**	Dry Bulb Temperature (°F)	Vapor Pressure (in. Hg)	Wind Speed (mph)	Prevailing Direction (NSEW)
Median of Extreme Highs	90	68	0.60	6.8	SW
0.4% Occurrence	81	66	0.54	7.2	W
1.0% Occurrence	76	65	0.50	6.5	W
2.0% Occurrence	72	64	0.49	6.6	W
Air Conditioning/		$T \geq 93$°F	$T \geq 80$°F	$T_{wb} \geq 73$°F	$T_{wb} \geq 67$°F
Humid Area Criteria	# of Hours	1	27	0	5

Other Site Data

Weather Region	Rain Rate 100 Year Recurrence (in./hr)	Basic Wind Speed 3 sec gust @ 33 ft 50 Year Recurrence (mph)	Ventilation Cooling Load Index (Ton-hr/cfm/yr) Base 75°F-RH 60% Latent + Sensible
8	2.5	85	0.0 + 0.0
Ground Water Temperature (°F) 50 Foot Depth *	Frost Depth 50 Year Recurrence (in.)	Ground Snow Load 50 Year Recurrence (lb/ft^2)	Average Annual Freeze-Thaw Cycles (#)
59.1	0	0	1

*Note: Temperatures at greater depths can be estimated by adding 1.5°F per 100 feet additional depth.

Figure 2-3
Example Temperature Range for Monterey, CA (from Reference 2.2)

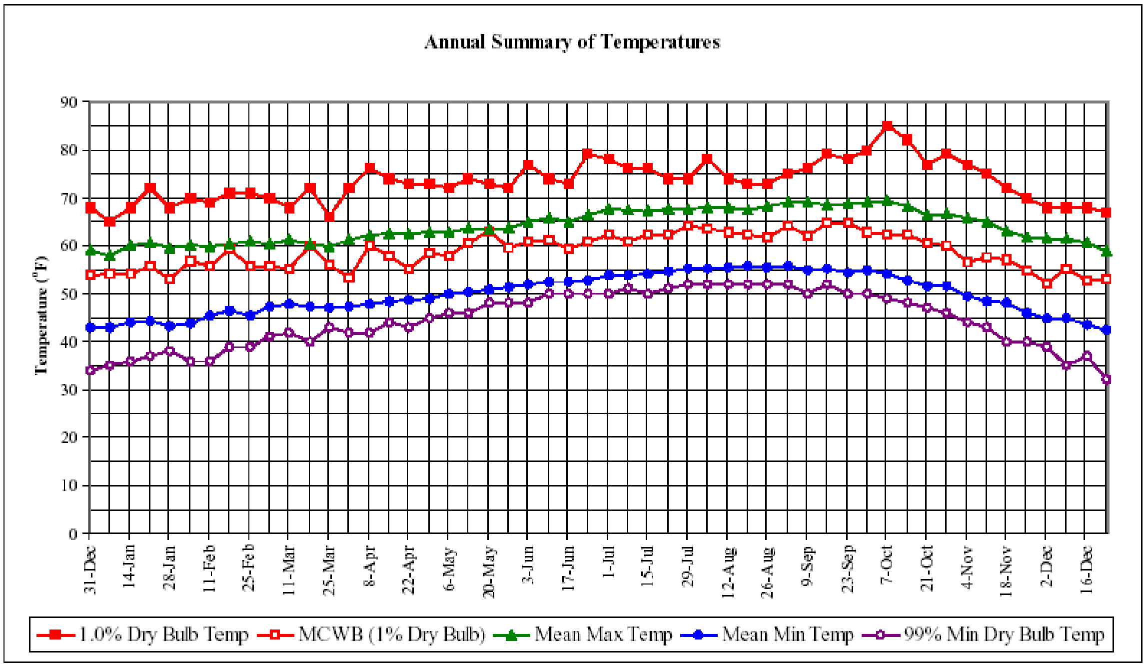


Figure 2-4
Annual Temperature Summary for Monterey, California (from Reference 2.2)

2.1 References

2.1 National Oceanographic Data Center, Coastal Water Temperature Guide, National Oceanographic and Atmospheric Administration, http://www.nodc.noaa.gov/dsdt/cwtg/spac.html

2.2 Engineering Weather Data, 2001 Interactive Edition, National Climatic Data Center, Climate Services Division, Asheville, NC.

3 METHODOLOGY FOR COOLING SYSTEM SPECIFICATION

3.1 Introduction

Cooling systems are an integral part of all plants which generate all or part of their power with condensing steam turbines, such as steam-electric or combined-cycle power plants. These systems condense the turbine exhaust steam and, in so doing, maintain the turbine exhaust pressure at the design level. Three general types of cooling system are in common use and are relevant to the discussion of 316 (b) retrofits at California coastal plants. These are:

- Once-through cooling
- Closed-cycle wet cooling
- Dry cooling

Once-though cooling has historically been the cooling system of choice, especially for plants on the coast or near other large waterbodies. It is the least expensive system and under most conditions provides coldest cooling water which corresponds to the most efficient and economical plant operation. In recent years, environmental concerns over the discharge of heated water to the environment (Clean Water Act; Section 316 (a)) and the impacts to fish and shellfish of withdrawing large quantities of water from natural waterbodies (Clean Water Act; Section 316 (b) and EPA's Phase I Rule) have led to the nearly universal adoption of closed-cycle cooling, usually wet cooling for new plants.

Closed-cycle wet cooling using mechanical-draft cooling towers[1] withdraw significantly less water into the plant for cooling and also discharge less back to the environment. In most situations, most of the water taken into the plant is evaporated to the atmosphere in the cooling process. The retrofit of plants using once-through cooling to closed-cycle wet cooling is frequently mentioned in the context of reducing the environmental consequences of entrainment and impingement losses. Closed-cycle wet cooling systems are typically more expensive than once-through cooling, even at new plants, and have higher operating power requirements and higher maintenance costs. They also typically provide less effective cooling with higher turbine exhaust pressure and higher plant heat rate.

[1] Natural-draft towers are not considered in this report. Their high capital cost/low operating cost characteristic is not appropriate for older plants with low capacity factors. In addition, there have been no natural daft towers built in the U.S. for over 25 years. While this may change, they are not now normally considered a commercially viable option.

Dry cooling, using mechanical, forced draft air-cooled condensers (ACC's), are being selected with increasing frequency for new plants, particularly those in water-short locations. Dry cooling equipment, while it reduces the amount of water required for plant cooling to essentially zero, is significantly more expensive that closed-cycle wet cooling in most situations and has higher operating power requirements. Plants with dry cooling can incur significant heat rate penalties for most of the year and particularly during periods of hot weather. Under some circumstances, during the hottest periods of the year, plant output may be limited by the performance of the dry cooling system. Dry cooling systems are seldom discussed in the context of once-through cooling retrofits.

The following sections will provide descriptions of the three types of cooling systems, review the design trade-offs for selecting optimum systems, present typical operating points and introduce the differences between new plant and existing plant retrofit situations.

3.2 Alternative Cooling Systems

3.2.1 Once-Through Cooling System Description

The typical once-through cooling system is illustrated schematically in Figure 3-1. Water is withdrawn from an adjacent natural waterbody, pumped through the tubes of a surface steam condenser where it is warmed by the heat of condensation of steam condensing on the outside of the tubes and returned to the same, or other nearby, waterbody.

The water enters the plant through an intake facility normally equipped with trash racks and traveling screens to exclude objects large enough to block or harm the cooling equipment and with some type of inlet screening designed to minimize impingement of fish at the inlet and the entrainment of smaller aquatic life into the cooling system. The intakes are located either at the shoreline or offshore with the location normally selected on environmental protection grounds. Similar considerations apply to the design and location of the discharge facility.

3.2.2 Once-Through Cooling Design and Optimization

Figure 3-2 shows the essential operating variables and defines the nomenclature for discussing system design and optimization. The essential information required for system design is

- Turbine exhaust steam flow
- Turbine exhaust pressure
- Source water temperature

At some locations, a maximum water withdrawal rate, and hence a maximum circulating water flow rate, would be specified on the basis of, for example, river conditions during periods of low river flow. For coastal plants withdrawing from the ocean, this is not a consideration.

For a once-through cooling system, the design trade-offs are relatively simple and straightforward. The design condensing temperature, T_{cond}, is set by the specified design backpressure for the steam turbine. The design cooling system inlet, or cold water temperature T_{cold}, would normally be chosen as the maximum expected source water temperature during the year. From Figure 3-2, the temperature difference between T_{cond} and T_{cold} is divided between the temperature rise of the cooling water as it passes through the condenser (the "range") and the terminal temperature difference of the condenser (TTD). For a given steam flow or heat load, the range is inversely proportional to the circulating water flow rate as shown in Equation 3-1.

$$(T_{hot} - T_{cold})\ [^{\circ}F] = Q[Btu/hr]/\{w_{circ}\ [lb/hr] * c_p\ [Btu/lb\text{-}^{\circ}F]\}$$ **Equation 3-1**

As shown in Figure 3-2, the required terminal temperature difference (TTD) is, therefore, given by

$$TTD\ [^{\circ}F] = (T_{cond} - T_{cold}) - (T_{hot} - T_{cold})$$
$$= (T_{cond} - T_{cold}) - Q\ /(w_{circ} * c_p)$$ **Equation 3-2**

and increases with increasing circulating water flow rate. The required TTD sets the size of the condenser with smaller TTD's requiring larger and hence more costly condensers.

Therefore, a higher circulating water flow gives a lower range, a higher TTD and a lower cost condenser but an increased circulating water system (pumps, motors, piping, intake/discharge facilities) cost and probably increased operating cost for a higher pumping power over the life of the plant.

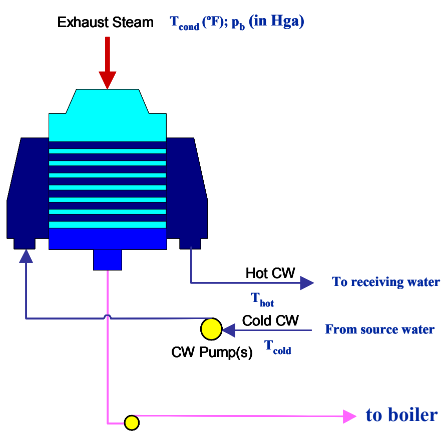


Figure 3-1
Once-Through Cooling Schematic

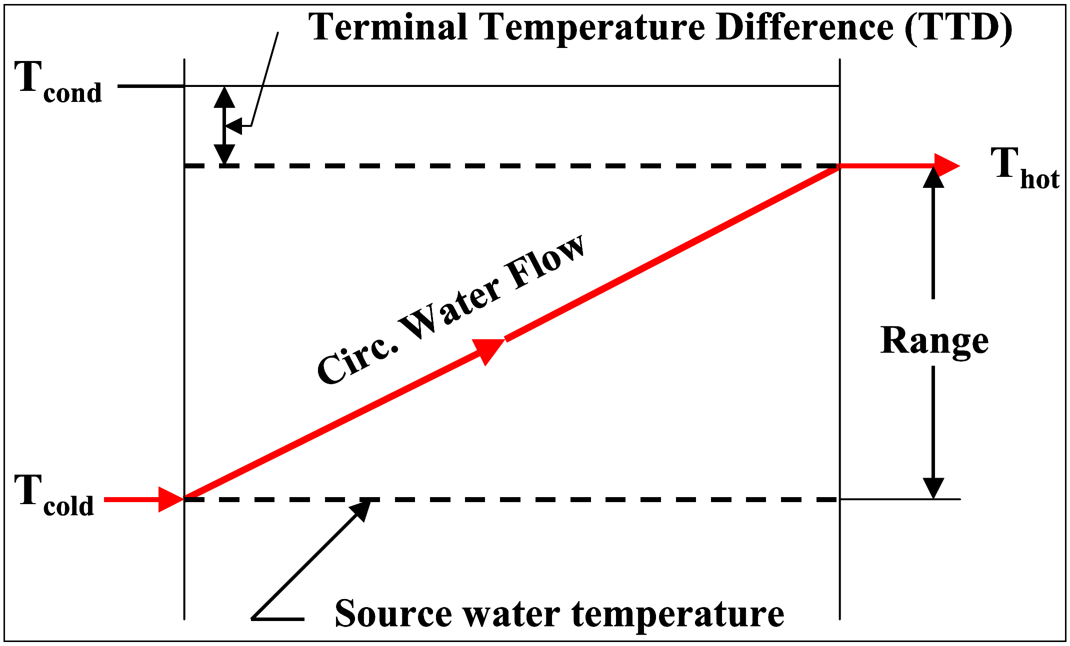


Figure 3-2
Once-Through Cooling Operating Nomenclature

Typical design points for fossil steam plants, assuming a plant heat rate of 10,000 Btu/kWh and a 15% stack loss, are

$w_{circ} = 500.$ gpm/MW
$Q \simeq 5{,}000$ Btu/kWh

From Equation 3-1, the range is therefore

$T_{hot} - T_{cold} = 20°F$

Assuming

$T_{cold} = 65°F$ (typical California summertime ocean temperature)
$T_{cond} = 92°F$ (corresponds to turbine exhaust pressure of ~1.5 in Hga)

the required TTD = 7°F, a typical design point for power plant surface steam condensers.

As will be seen in discussions of individual power plants in Appendix B these values are consistent with most of the once-through cooling system designs at the California coastal plants.

3.2.3 Closed-Cycle Wet Cooling System Description

Recirculating cooling systems are similar to once-through systems in that the steam is condensed in water-cooled, shell-and-tube surface condensers, but different in that the heated cooling water is not returned to the environment. Instead, it is conveyed to a cooling component, typically a mechanical-draft, wet cooling tower and then re-circulated to the condenser. A typical system with a cooling tower is shown schematically in Figure 3-3. Note that the schematic in Figure 3-3 depicts a cross-flow tower, while nearly all current tower designs are of the counter-flow type. For the purposes of this discussion, the difference is not important.

Advantages are

- Reduced withdrawal rates
- Reduced entrainment/impingement
- Reduced thermal discharge plumes

Disadvantages are

- Decreased plant efficiency (from reduced thermal efficiency and increased auxiliary load)
- Higher capital cost
- Higher water consumption through evaporation (only an issue in freshwater)
- Visible plume/drift emissions
- Wastewater treatment requirements
- Chemical treatment programs
- Adverse environmental impacts of closed-cycle cooling
  - Air emissions
  - Wastewater discharge
  - Waste disposal
- Site space
- Noise
- Terrestrial ecological issues

The cooling is achieved by the evaporation of a small fraction (typically 1 to 2%) of the recirculating water flow. Therefore, once the system is filled, the only water withdrawn from the environment is makeup water in amounts sufficient to replace that lost to evaporation, blowdown,[2] and drift.[3] Therefore, withdrawal rates from the environment are much less than for once-through systems—typically 10 to 15 gpm/MWe (600 to 900 gal/MWh).

A certain amount of water must be "blown down" from the system in order to control the build-up of dissolved and suspended solids in which enter the system in the make-up water and are then concentrated by the evaporation process. The amount of blowdown is normally characterized as a fraction of the make-up water through the "cycles of concentration, n, given by

[2] Blowdown is water discharged from the cooling system in order to control the buildup of dissolved and suspended materials that concentrate in the system as a result of the evaporation.

[3] Drift refers to liquid water droplets entrained in the tower exit plume and released to the atmosphere.

$n = w_{make\text{-}up}/w_{blowdown}$

where for fresh water towers n typically ranges from 5. to 10, while for salt water or brackish water towers it is as low as 1.5 to 2. The blowdown must either be discharged to the environment under NPDES rules or recycled, concentrated and eventually disposed of on-site under "zero-liquid discharge" (ZLD) regulations. For salt water make-up towers, zero liquid discharge is impractical.

It should further be noted that tower operation at low cycles of concentration, the amount of make-up water required can be substantially increased. For fresh water towers, operating at between 5 and 10 cycles of concentration, the make up exceeds the amount required for evaporation by only 10 to 20 %. For salt water towers, operating at 1.5 cycles of concentration, the make-up requirements are three times what is evaporated in the tower.

This is an important distinction when considering the percentage reduction in withdrawal from what is required for once-through cooling. If it is assumed that once-through cooling withdrawal rates are 500 gpm/MW and cooling tower consumptions rates are 10 gpm/MW, a tower operating at 10 cycles of concentration will reduce the withdrawal rate by 97.8 % whereas a tower operating at 1.5 cycles of concentration will reduce it by 94%.

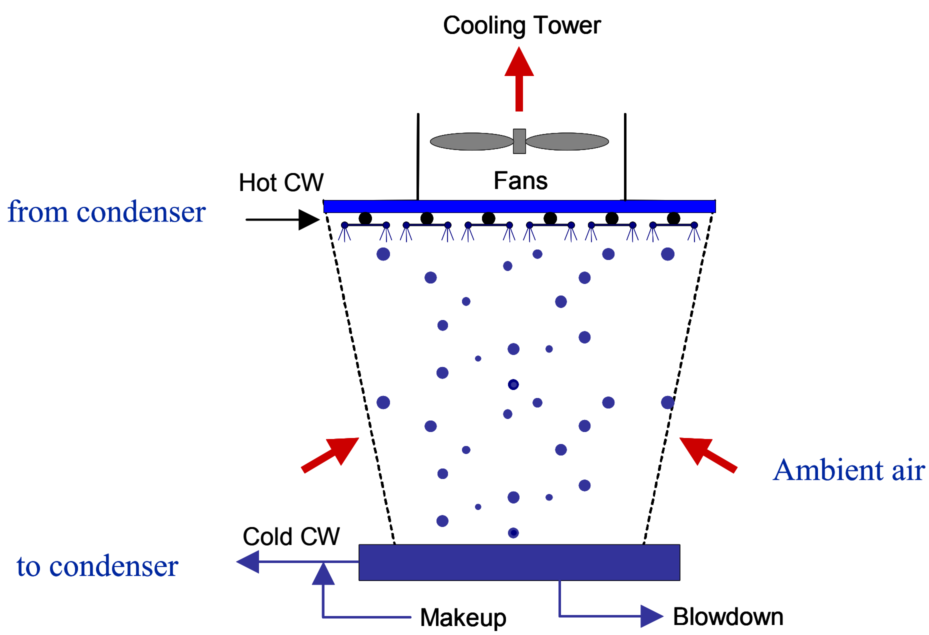


Figure 3-3
Closed-Cycle Wet Cooling (Mechanical Draft Tower) Schematic

3.2.4 Closed-Cycle Wet Cooling Design and Optimization

The design selection and optimization procedure for closed-cycle wet cooling systems is more complex that it is for once-through systems.

The minimum information for the design specification is

- Turbine exhaust steam flow

- Turbine exhaust pressure
- Ambient wet bulb temperature

As shown in Figure 3-4, for a specified ambient wet bulb temperature and turbine exhaust pressure, the cooling system is constrained to operate between T_{cond}, set by the design backpressure, and $T_{amb.\ wb}$. This overall temperature difference is made-up of the cooling tower approach, the condenser range, and the condenser TTD. As in the case of once-through cooling, the design heat load, Q, and the choice of the circulating water flow, w_{circ} determines the range. The TTD is set by the size of the condenser. The cooling tower approach is set by the size of the cooling tower and the fan power providing the air flow to the tower.

Therefore, several trade-offs are available.

- For a given circulating water flow rate, the size and cost of the condenser can be traded off against the size and cost of the cooling tower as a smaller approach (bigger more costly tower) permits a larger TTD (smaller, less costly condenser).
- For a given tower approach, tower size (and capital cost) can be traded off against tower fan power. Smaller towers using more fan power can deliver the same approach as a larger tower with less fan power. The trade-off is between initial capital cost and continuing operating cost. The typical limiting cases are a "low first cost" design requiring high fan power over the operating life of the tower or a "minimum evaluated cost" which optimizes the size vs. fan power trade-off for a given set of economic and plant life assumptions, to achieve the lowest life cycle cost of the tower.
- A higher circulating water flow rate will reduce the range and permit either the condenser, the cooling tower or both to operate at higher approach/TTD for reduced capital cost.

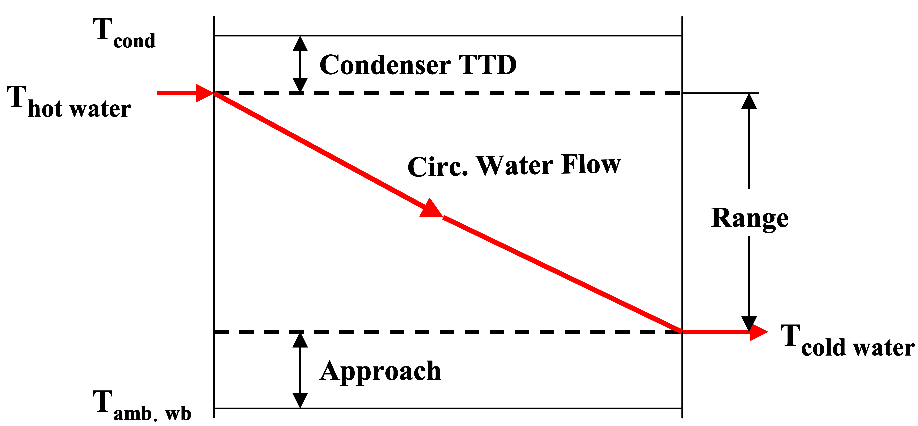


Figure 3-4
Closed-Cycle Wet Cooling (Mechanical Draft Tower) Operating Variables

In addition, a more global optimization may be carried out to refine the selection of the design point. System optimization to minimize total life cycle cost involves the trade-off between cooling system capital cost and future operating and penalty cost. A larger, more effective cooling system costs more initially and may consume more power in operation but will provide higher plant efficiency and generating capacity (lower fuel cost, increased revenue) over the life of the plant. Conversely, a smaller, cheaper cooling system will incur higher operating and penalty costs.

To carry out a total evaluated cost optimization, the following information is required.

- Annual wet bulb temperature duration curve
- Turbine heat rate curve
- Value of power ($/kW)
- Assumed plant life and capacity factor
- Inflation/amortization factors

Using this information, a complete, rigorous optimization would involve sizing the cooling system for a range of design points (different backpressures and ambient wet bulb temperatures) and then calculating the resulting turbine backpressure, plant heat rate, fuel consumption, power generated and water use on a day by day or hour by hour basis throughout the year. The resulting operating and penalty costs would be accrued for the first year and then summed and discounted for the future years of the expected plant life to obtain a total life cycle cost. A global minimum would be sought to determine the optimized cooling system design to be compared with similarly optimized systems of alternative types. The choice of plant life, discount rate, and a host of other economic and business factors would be chosen based in part on the business objectives and corporate policies of the plant developer. These choices could have as much influence on the final selection as the thermal performance of the cooling system.

In practice, this is rarely done at least for wet cooling systems. Experience has evolved general rules which guide the selection of the initial design point and hence set the size, cooling capability, power requirements and initial cost of the cooling system. The considerations vary somewhat with plant and cooling system type.

The usual procedure is to optimize a cooling system design using the turbine design backpressure and the 1% wet bulb (the wet bulb temperature which is exceeded only 1% of the year or about 90 hours). This choice essentially ensures that the design backpressure will be maintained throughout the year. Furthermore, in most locations, the annual maximum wet bulb temperature exceeds the 1% wet bulb by only a degree or two. Therefore, even at extreme conditions, the backpressure will be close to design and there will be no danger of approaching the maximum backpressure limits of the steam turbine. As will be discussed in a later section, the penalty costs are much more important for the optimization of dry cooling systems, and a global optimization of the type described above is more commonly used.

In addition, a recirculation allowance is normally included to account for an increase in the effective inlet wet bulb temperature due to recirculation of a portion of the saturated exit plume into the inlet flow. The amount of recirculation depends on wind speed and direction and on the orientation of the cooling tower relative to the wind direction. A common assumption is to increase the design inlet wet bulb by 3 ºF but under some circumstances the effect of recirculation can be larger. The effect of including a recirculation allowance may, in fact, be a slight decrease in the tower size and initial cost but an increase in the heat rate and energy penalty.

As a general rule, closed-cycle cooling systems optimize at a lower circulating water flow rate and a higher range than a once-through system. This is due in part to higher pumping power required to lift the water to the top of the tower in addition to pumping it through the condenser as is required in both systems.

A typical operating point might be:

w_{circ} = 400. gpm/MW

$T_{hot} - T_{cold}$ (Range) = 25°F

$T_{cold} - T_{amb.\ wb}$ (Approach) = 10°F

$T_{cond} - T_{hot}$ (TTD) = 7°F

$T_{amb.\ wb}$ = 65°F (typical 1. % wet bulb for California coast)

giving a condensing temperature, T_{cond}, equal to 107°F, corresponding approximately to a 2.5 in Hga turbine exhaust pressure which is a typical design point for turbines designed for operation with closed-cycle cooling.

3.2.5 Closed-Cycle Wet Cooling As A Retrofit Technology

The discussion above sets out the usual approach for the design and selection of closed-cycle wet cooling systems for new plants. When these systems are considered as a retrofit option on plants designed for, built with and operated on once-through cooling the situation can be very different and preclude any degree of optimization. The following constraints are normally present.

- The condenser is already in place and has been designed for a certain flow rate, a certain range and a certain TTD. Therefore, the operating point for the cooling tower is fixed. As noted above, closed-cycle cooling systems normally optimize at a lower circulating water flow and higher range than do once-through systems. In a retrofit, the tower will have to be designed to operate at off-optimum conditions.
- The steam turbine was originally selected on the assumption that once-through cooling would be used. Therefore, particularly for older plants, the design turbine exhaust pressure is likely to be in the range of 1.0 to 1.5 in Hga as opposed to the more usual 2.5 in Hga for modern turbines designed for use with cooling towers. The ambient wet bulb temperature during the hotter periods of the year typically exceeds the temperature of local waterbodies, particularly in the case of ocean plants. It may be impractical and uneconomic or even impossible to achieve the design backpressure with a closed-cycle cooling system with the existing plant condenser and circulating water system. In such cases, the operating penalty of the closed-cycle system, when compared to the original once-through system may be important.
- For older plants with low capacity factors, the design trade-offs for the cooling tower will tend toward a choice of low initial cost and higher operating cost since there will be less time to recoup any initial investment made at the beginning through lower power costs over the remaining hours of plant operation.

- If retrofit is required on a plant that has a long anticipated remaining life and a high capacity factor, it may be appropriate to modify the condenser and the recirculating system in order to re-optimize the cooling system for a minimum life cycle cost for the remaining life of the plant. As will be discussed later, this can add a great deal to the cost of a retrofit project, but, under certain sets of business projections for a given plant, it may be the correct economic choice.
- Finally, it will often be the case that the addition of a cooling tower to the cooling circuit will necessitate some extensive modifications to the existing condenser and circulating water pumps and piping in order to prevent potential equipment damage and failure. These will be discussed in a later section under the more detailed discussion of retrofit costs.

3.2.6 Dry Cooling Design Description

The typical closed-cycle dry cooling system with a forced-draft ACC is illustrated schematically in Figure 3-5. A more detailed illustration is shown in Figure 3-6.

Turbine exhaust steam is ducted from the turbine exit through a series of large horizontal ducts to a lower steam header feeding several vertical risers. Each riser delivers steam to a steam distribution manifold which runs horizontally along the apex of a row of finned-tube, air-cooled heat exchangers arranged in an A-frame (or delta) configuration. A typical full-scale ACC consists of several such rows, sometimes referred to as “streets” or “lanes”.

Each street consists of several cells. Each cell consists of several bundles of finned tubes arranged as parallel, inclined bundles in both walls of the A-frame cell. (See Figure 3-6). Steam from the steam distribution manifold enters the tubes at the top, condenses on the inner tube walls and flows downward (co-current with remaining uncondensed steam) to condensate headers at the bottom of the bundles. One cell in each row (typically one out of five or six, centrally placed along the row) is a “reflux” or “dephlegmator” cell, included for removal of non-condensable gases from the condenser. Uncondensed steam from the other cells in the row, along with entrained non-condensables, flows along the condensate header to the bottom of the reflux cell tube bundles. An air-removal system (vacuum pump or steam ejector) removes the non-condensables through the top of the reflux cell bundles. Additional condensation takes place in this cell and the condensate runs down (flowing counter-current to the entering steam) into the condensate header. The condensate flows by gravity to a condensate receiver tank from which it is pumped back to the boiler or Heat Recovery Steam Generator.

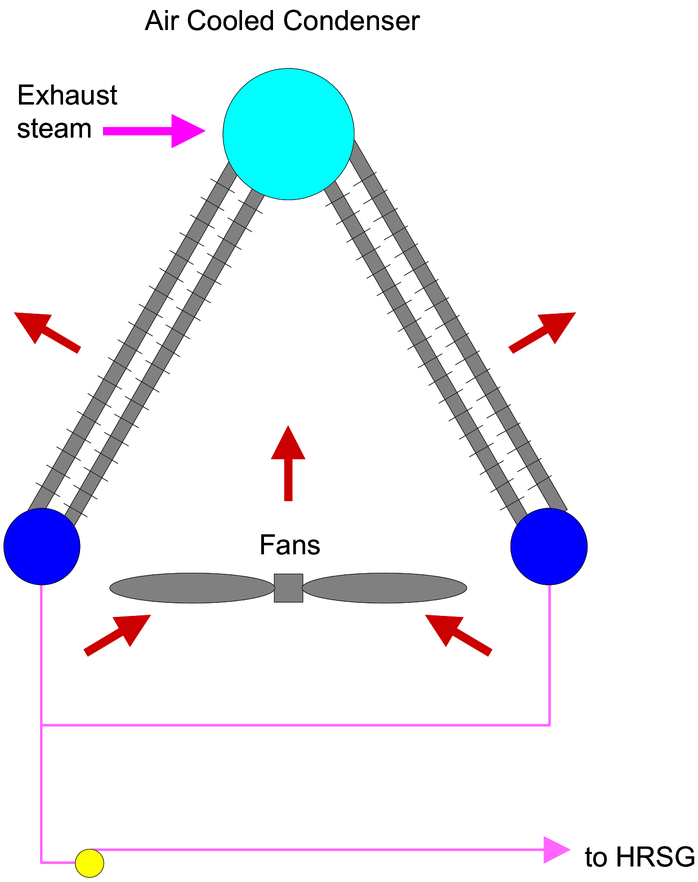


Figure 3-5
Dry Cooling (ACC) Schematic

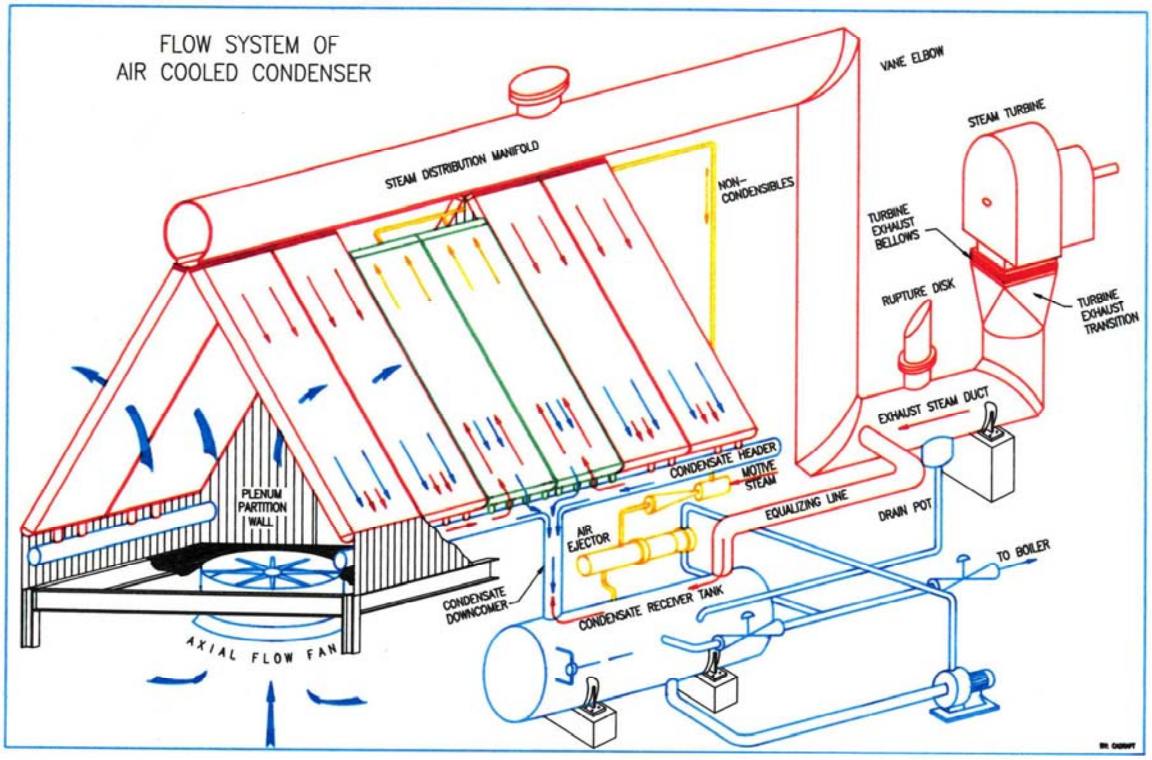


Figure 3-6
Schematic of Air-Cooled Condenser (Courtesy of Marley Cooling Tower Company)

Large [typically about 10 meter] axial flow fans are located in the floor of the cells providing forced-draft air cooling to the finned-tube heat exchangers. They are typically low speed, two-speed (100/50 rpm) with five to eight blades. Designs vary considerably depending on allowable noise levels at the site.

3.2.7 Dry Cooling Design and Optimization

Figure 3-7 shows the operating variables and defines the nomenclature for the specification of air-cooled condensers. The selection of an optimized design for a dry cooling system is based on the trade-off between initial capital costs and annual performance penalties. Unlike the situation with closed-cycle wet cooling systems discussed above, the performance penalties associated with increased heat rate during hotter periods of the year and the possibility of reduced plant output on the very hottest days is an overriding consideration for the optimization of dry systems.

The minimum information for design specification of the ACC itself is

- Turbine exhaust steam flow
- Turbine exhaust pressure
- Ambient (dry bulb) temperature

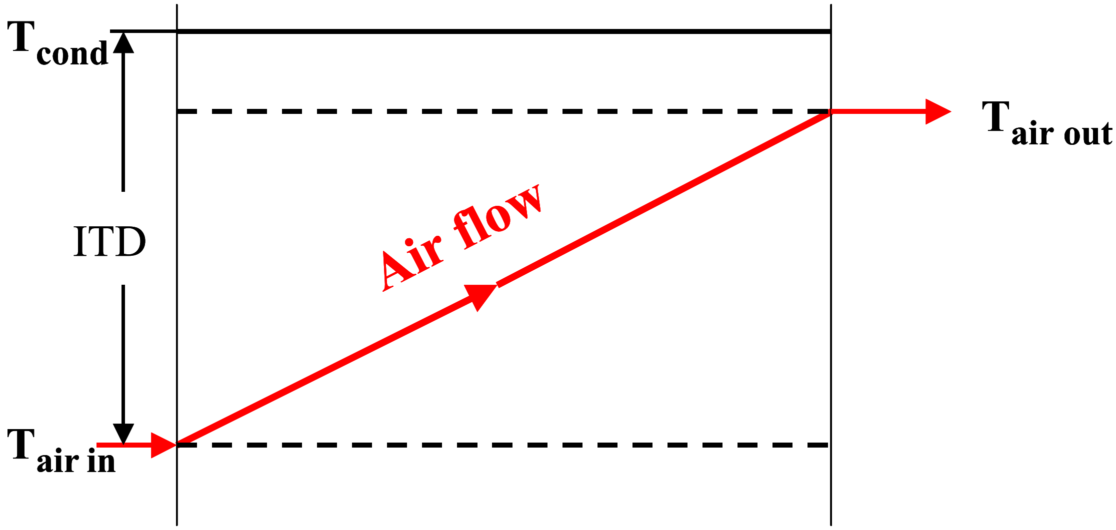


Figure 3-7
Dry Cooling (ACC) Operating Variables

However, the selection of the design point values of ambient dry bulb and turbine exhaust pressure is the critical decision in the optimization process. The design point ambient dry bulb temperature for air-cooled condensers is typically closer to either the summer- or annual-average temperature. This results in a better trade-off between initial capital cost and performance penalties than would a higher (as, for example, a 1% dry bulb) temperature design point. This situation differs from the wet cooling case, in part, because of the greater annual variability of the dry bulb temperature in comparison to the wet bulb temperature. The 1% dry bulb exceeds the annual average temperature by 30 to 40°F in many locations, whereas the 1% wet bulb typically exceeds the annual average wet bulb by less than 10°F. A rigorous determination of the optimum design point for dry systems requires extensive analysis and a calculation of the penalty costs for a range of choices. In addition, in order to carry out a total evaluated cost optimization, the following information would be required.

- Annual temperature duration curve
- Turbine heat rate curve
- Value of power ($/kW)
- Cost of replacement power
- Assumed plant life an capacity factor
- Inflation/amortization factors

A detailed discussion of the complete design optimization procedure for dry cooling is given in two recent reports by the California Energy Commission [3.1] and EPRI [3.2] and is summarized briefly here for convenience of reference.

Climates typical of coastal California are somewhat more favorable for dry cooling than those in very hot desert areas since the variability in ambient temperature is much less and the annual extreme highs are much lower. A reasonable choice of the design point, chosen without conducting the complete optimization procedure, might be

T_{cond} = 110°F (~ 2.5 in Hga backpressure)
$T_{amb\ design}$ = 65°F (average summer temperature for coastal California)

This corresponds to an initial temperature difference (ITD) of 45°F which is reasonably typical of modern ACC designs for moderate climates. [3.3].

3.2.8 Retrofitting With Dry Cooling

Although dry cooling systems are being installed more frequently on new plants in recent years, the consideration of dry cooling as a retrofit option for existing plants is quite different.

Two considerations are paramount.

- Existing plants originally designed for once-through ocean cooling are equipped with older turbines with much more stringent limitations on exhaust pressure than those for modern turbines designed for use with dry cooling. Typical limits for older existing turbines would be an “alarm” point of 4.0 to 4.5 in Hga and a “trip” point of 4.5 to 5.0 in Hga.
- Plants with low capacity factors typically operate *only* at times of the highest system demand. Therefore, it is imperative that the cooling system be designed to maintain an acceptable turbine backpressure during the hottest hours. Under that criterion the normal optimization procedures which trade off efficiency and capacity penalties for a few hot periods against the reduced capital cost for a smaller ACC no longer apply.

For example, the design criterion should be that the backpressure not exceed 4.5 in Hga at the median of extreme high summer temperatures. This leads to the following ACC design selections.

Table 3-1
ITD Range for Coastal California Meteorology

Site Location	Design ambient, °F	Design ITD, °F
San Clemente/Monterey	85°F	45
San Diego/San Francisco	95°F	35
Long Beach	105°F	25

ITD’s in the range of 25 to 35°F result in very large and very costly ACC’s for a given plant capacity or heat load. This, in conjunction with the large footprint of ACC’s in comparison with wet towers and the difficulty of ducting steam out from existing turbine/condenser arrangements in older plants, presents formidable difficulties to the use of dry cooling in retrofit situations. The difficulties and the associated costs will be discussed in a later section.

3.2 References

3.1 California Energy Commission, “Comparison of Alternate Cooling Technologies for California Power Plants; Economic, Environmental and Other Tradeoffs”, PIER Report No. P500-02-079F, February, 2002.

3.2 *Comparison of Alternate Cooling Technologies for U.S. Power Plants.* EPRI, August 2004. EPRI Report No. 1005358.

3.3 Sanderlin, David, “Dry cooling history in North American Power Plants”, presented at AWMA Symposium on Dry Cooling for Power Plants- Is This the Future?, San Diego, CA, May, 2002.

4
COOLING SYSTEM COST ELEMENTS

This section identifies the major cost elements for both wet and dry closed-cycle cooling systems. Wet closed-cycle cooling systems are commonly used on new plants and dry cooling systems have become more common in recent years. As a result, the component and system costs are reasonably well established and the comparative importance of the several elements is well understood.

In order to provide a credible, well-documented basis from which retrofit costs can be extrapolated, the cost elements for the cooling systems will be listed and a general discussion of the factors affecting the most important of the cost elements will be discussed in the context of new plant construction. In Section 5, example system optimization procedures and cost estimates for new plants will be derived. In Section 6, the procedures will be re-visited and the cost estimates revised for retrofit situations of varying degrees of difficulty.

4.1 Cost Elements—Wet Cooling Systems

The major components of a closed-cycle wet cooling system are:

- the cooling tower,
- the steam surface condenser,
- the circulating water system,
- any necessary water treatment facility and
- the intake and discharge structures.

Cost information on each of these components including both capital equipment cost and related installation cost is discussed in the following paragraphs.

4.1.1 Cooling Tower

For purposes of this study, all cooling towers will be assumed to be mechanical-draft, counter-flow towers of *f*iber-*r*einforced *p*olymer (FRP) construction, sized and designed with materials and fill suitable for operation with seawater make-up. The tower itself is quoted as an erected structure including the support columns, internal structural members, fill, drift eliminators, fans, fan motors and related miscellaneous equipment such as stairs and railings.

Additional major cost items, usually quoted, or at least estimated separately, are:

- Cold water basin—Towers are built on a concrete basin which collects the water falling from the tower and provides some measure of cold water storage to accommodate minor system transients. It extends completely under the tower cells and a few feet beyond. It is typically 4 to 5 feet deep with 8” to 10” thick walls and floor. The basin cost, usually quoted in cost per square foot of basin area, includes “typical” site preparation. Unusual or difficult geological features of a site such as, for example, soft, marshy soil requiring extensive piling or other stabilization or steep, irregular contours requiring extensive earth-moving to provide a level basin pad will increase the cost.
- Motor wiring and controls—The hook-up of the power, instrumentation and control cables and control boxes are quoted separately usually on a “per cell” basis. A separate *m*otor *c*ontrol *c*enter (MCC) building is usually provided at a cost that may be dependent on site meteorology.
- Minor items such as fire and lightning protection systems, lighting, etc.

4.1.2 Steam Surface Condenser

In the case of a wet cooling system being designed for installation at a new plant, the steam condenser is usually the second largest cost item after the cooling tower itself. In addition, as was discussed in Section 3, an important part of the cost minimization is the performance optimization procedure in which the size and cost of the cooling tower is traded off against the size and cost of the condenser. Condenser costs, particularly in seawater systems where titanium tubes are normally selected can be a major (40 to 50%) portion of the total system cost.

For most retrofit projects, the existing condenser is used “as is” and does not enter into the retrofit cost. However, two things must be remembered. First, for large, baseload (or at least high capacity factor) plants with long (15 to 20+ years) of remaining, post-retrofit life, a life cycle economic analysis will likely indicate that the condenser must be modified or replaced in order to have an optimized cooling system. This situation, for which total costs are very difficult to estimate, will be discussed again in a later section in the context of the two large nuclear plants on the California coast.

Second, for all plants regardless of capacity factor, the introduction of a cooling tower into the circulating water loop will often result in a significantly increased static pressure in the inlet and outlet water boxes. This may require stiffening of the tube sheets or other reinforcement in order to prevent deformation and leakage or even structural damage. This too will be discussed in a later section.

4.1.3 Circulating Water System

A circulating water system for a once-through cooling system is shown schematically in Figure 4-1. A single set of circulating water pumps withdraws water from the cooling water inlet system (CWIS), pumps it through the condenser tubes and returns it to the discharge.

The typical circulating water system arrangement for a new plant designed with closed-cycle cooling is shown in Figure 4-2.

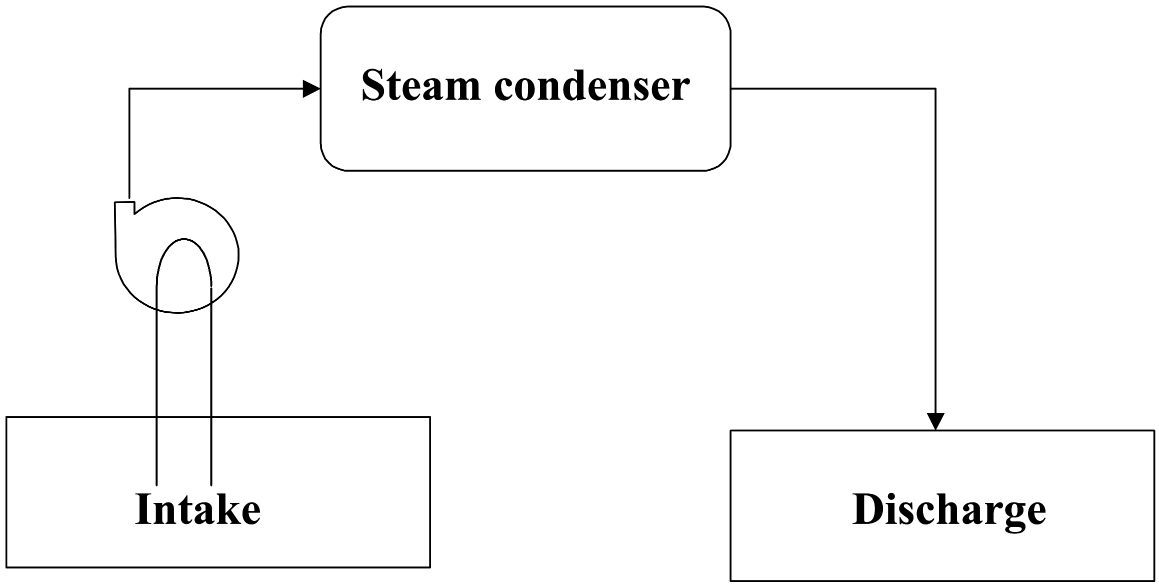


Figure 4-1
Once-Through Circulating Water System

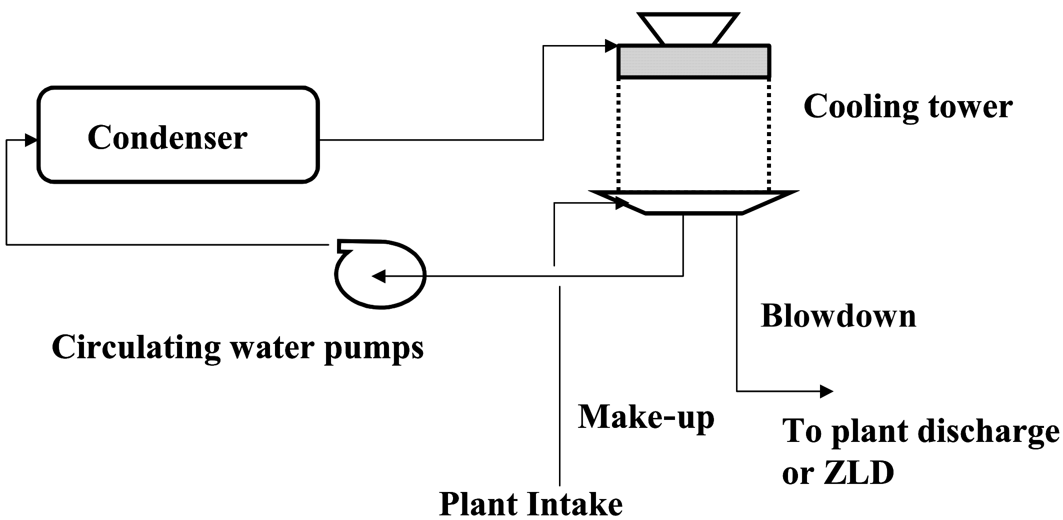


Figure 4-2
Circulating Water System for Closed-Cycle Wet Cooling

Typically the circulating water pumps withdraw from the cooling tower basin, pump the water through the condenser and back to the distribution deck at the top of the tower. The major elements of the circulating water system are circulating water lines between the condenser and the cooling tower and the circulating water pumps themselves. These costs vary with the design circulating water flow rate which is selected as part of the optimization procedure as discussed in Section 3 and with the required length of the circulating water lines.

Cooling water make-up to replace water lost to evaporation, blowdown and drift is drawn from the plant source water and added to the basin. Blowdown, to maintain an acceptable level of dissolved and suspended solids in the circulating water, is drawn from either the hot or cold side of the system and discharged either to a receiving water or pumped to a treatment system on the plant for recycle or for further evaporation and perhaps crystallization for disposal under zero liquid discharge constraints.

The intake and discharge structures for closed-cycle cooling systems typically handle only a small fraction (< 5%) of the flow for once-through systems. Make-up and blowdown pumps and piping are required but they too are much smaller and less costly than the main circulating water system components.

The retrofit installation of closed-cycle cooling at a plant originally built with once-through cooling is more complex. It is not simply a matter of installing a cooling tower in the existing circulating water system for several reasons. As noted earlier, the approach is usually, but not always, to keep the existing condenser, circulating water flow rate and as much of the existing circulating water pumps, lines and intake/discharge structure as possible unchanged. However, a number of site-specific items must be considered.

1. A suitable location with enough room for the tower must be found on or adjacent to the plant site. This may place the tower far from the turbine hall and require very long circulating water lines.
2. The discharge head from the circulating water pump must be increased in order to get the water to the top of the cooling tower and to overcome any additional head loss in the new circulating water lines.
3. This additional head may be obtained by replacing or modifying the existing pump to obtain higher discharge head as illustrated in Figure 4-3. This would involve diverting the condenser discharge flow from its current route, installing a new line to the cooling tower and a new return line back to the existing intake bay. Additionally, new make-up and blowdown lines and pumps would need to be installed as described above for new installations.
4. The existing inlet and discharge structures will have been designed for much higher flows than will be experienced with the closed-cycle system. This may lead to silting or fouling and will require either that they be modified to restrict the flow area or be replaced with smaller, more suitable structures.
5. With this approach, the pressure in the condenser water boxes and any remaining discharge lines from the existing condenser will be subject to much higher pressure. This may require reinforcement or replacement in order to avoid leakage or damage.

Figure 4-3 shows an arrangement that is more likely to be the preferred choice for cooling tower retrofits. In this approach, the hot water flow off the condenser is discharged into a pit or sump, which must be installed with corresponding additional cost and space requirements. From there a new set of circulating water pumps withdraws the water and delivers it to the hot water distribution deck at the top of the cooling tower. The cold water off the tower is then returned to the inlet bay of the original circulating water circuit. This eliminates the need to stiffen or reinforce the condenser to withstand the higher waterbox pressures that the approach in Figure 4-3 imposes on the unit.

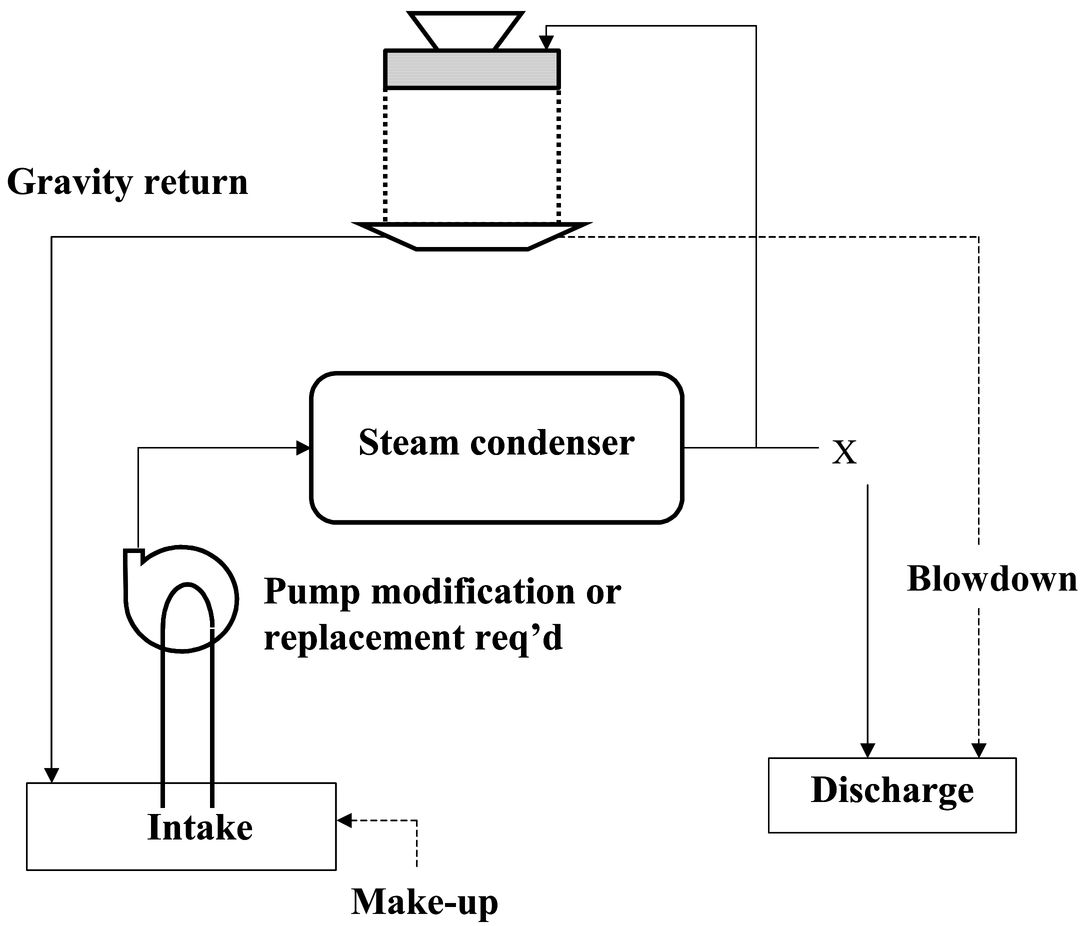


Figure 4-3
Possible Retrofit Option for Closed-Cycle Wet Cooling

It is desirable to construct the tower basin at a sufficiently high elevation to allow gravity drain of the cold water back to the intake. If this is not possible, either a second set of circulating water pumps must be installed in the return line or the original set of pumps must be replaced or upgraded (and perhaps the condenser as well) in order to used the approach discussed above and illustrated in Figure 4-3. In this case, as well as the other, make-up and blowdown pumps, piping and intake/discharge structures are required.

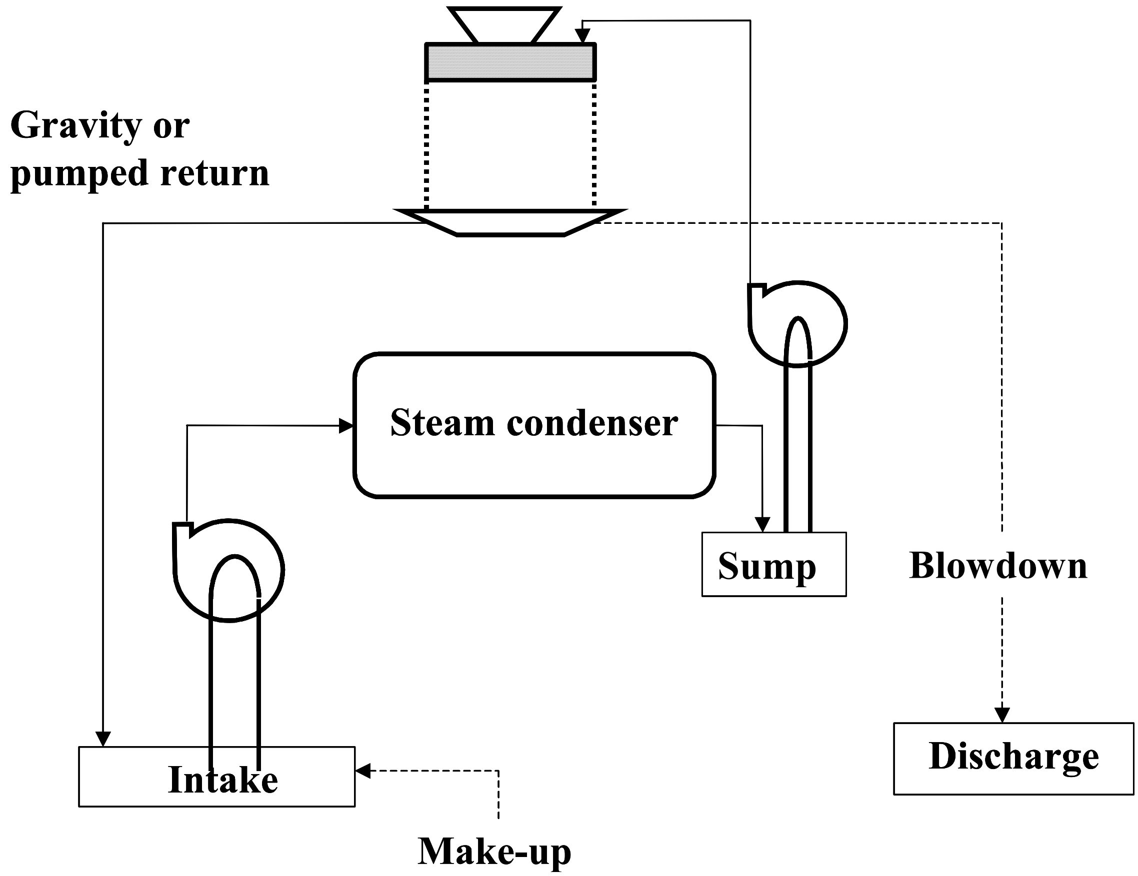


Figure 4-4
Preferred Retrofit Option for Closed-Cycle Wet Cooling

4.1.4 Wet Cooling System Cost Ranges

A number of fairly recent studies have developed cost estimates for wet cooling systems for new plants. These include EPA [4.1], The Washington Group [4.2] and EPRI [4.3] among others. The details of the scope and content of the costs developed in the EPA and Washington Group studies will not be repeated here. Sections 5 and 6 of this report gives some general overview information about how the costs were arrived and what they included. A summary of the conclusions and approximate cost ranges is provided for convenience of reference and to give a point of departure for evaluating the likely level and judging the reasonableness of the retrofit discussions in later chapters.

The remaining material in this section is taken from the EPRI study [4.3] with some updating of the ranges to 2007 dollars. Condenser costs are not discussed since, in virtually all retrofit cases, the original condenser will be retained.

The basic wet cooling tower design chosen is a mechanical-draft, counter-flow, in-line configuration of FRP (fiber-reinforced plastic) construction, as is typical of current installations. Design, performance and cost information was obtained for a given heat load at a specified hot water temperature (corresponding to the design turbine condensing temperature and an assumed condenser TTD) for a set of tower ranges and ambient wet bulb temperatures.

The specified conditions were:

- Tower Heat Duty: 1.08×10^9 Btu/hr
- Hot Water Temperature: 104°F
- Minimum Approach 5°F
- Tower Range: 15 to 30°F
- Ambient Wet Bulb: 65 to 80°F.

Additional assumptions included:

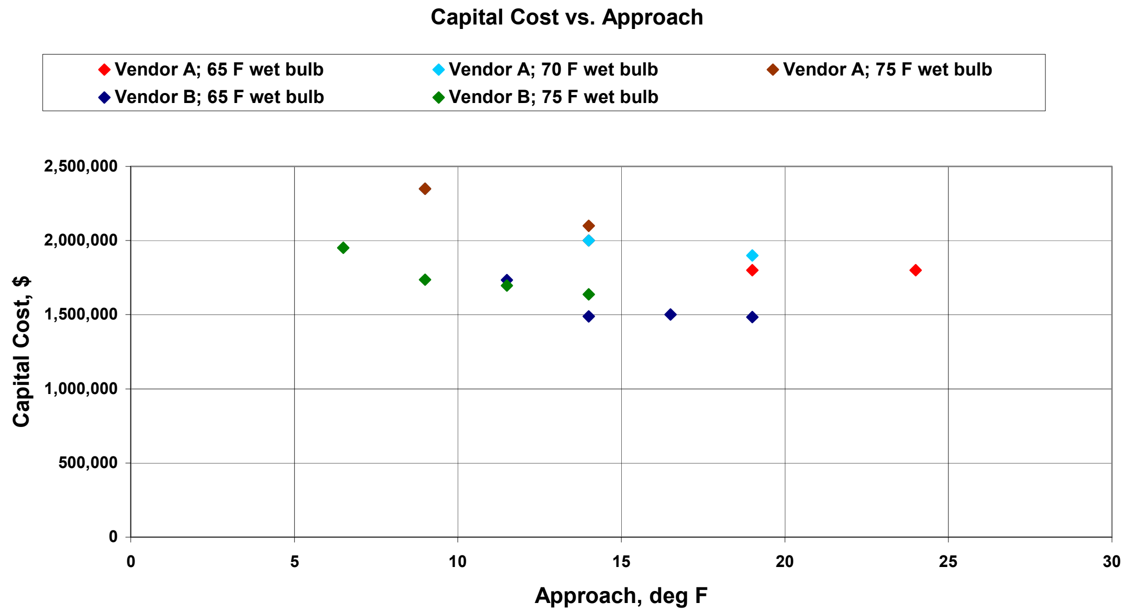
- Site elevation: Sea level
- Water quality: Fresh, good quality make-up;
5 cycles of concentration
Circ. Water properties—TSS < 100 ppm
—TDS < 1000 – 2,500 ppm
—Chlorides 100 – 1000 ppm
—pH ~ 8.0 to 8.5
- Noise limitations: No constraints other than OSHA.

Note that the original cost development was done for specified tower heat load of approximately 1 million Btu per hour. In the context of the California coastal, gas-fired steam plants this corresponds to a unit size of approximately 200 MW. Costs for towers with different heat loads can reasonably be estimated by a linear scaling on the basis of heat load, assuming that the circulating water flow, range and approach are held constant. In the original costs estimates were done for fresh water towers. In addition to updating the following costs from 2002 to 2007 dollars, it is appropriate to increase the tower costs by about 7% to account for the reduced performance, increased size and more costly materials necessitated by the use of seawater make-up.

Estimates were made both for a "low first-cost" design as well as a "minimum evaluated cost" design for a specified present value power cost of $2,500/kW. While the likely choice for a new plant would be the "minimum evaluated cost" design (evaluated for whatever present value power cost would be most appropriate for the individual case being considered), in the case of retrofit, particularly for older, lower capacity factor plants, the "low first cost" design would probably be chosen as discussed earlier.

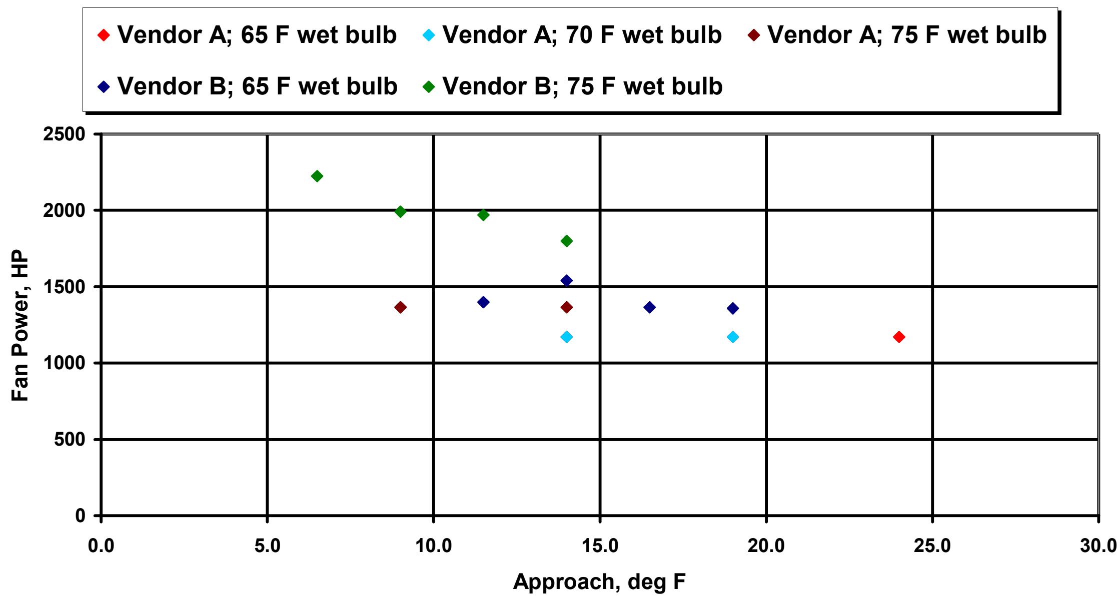
Figures 4-5a and 4-5b reproduce capital cost and fan power estimates from Reference 4.3.

Figure 4-5b shows a consistent and significant difference in the range of ~ 20 to 30% in the price estimates between vendors. This is not an unexpected result since a "low first-cost" design is not as well specified as a minimum evaluated cost design. Within reason, the tower size can always be reduced and the cost lowered at the expense of additional power. Opinions on what constitutes a reasonable "low first cost" may vary from vendor to vendor, depending on their experience with prior bids and their sense of prevailing market conditions. This is illustrated by the comparisons of capital cost (in Figure 4-5a) where Vendor A's costs are consistently higher than Vendor B's while Vendors A's power requirements (in Figure 4-5b) are generally lower. In any case the agreement is adequate for the degree of precision required in this study.



(a)

Figure 4-5
"Low First Cost" Cooling Tower Capital Cost Estimates (from Reference 4.3)



(b)

Figure 4-5
"Low First Cost" Cooling Tower Capital Cost Estimates (from Reference 4.3) (Continued)

All of the features of the designs on which the estimates were based were reasonably consistent. At a design approach of 10°F which is reasonable for conditions on the California coast, the tower sizes ranged from 6 to 8 cells with design flows of approximately 10,000 gpm per cell, fan power from 125 to 150 HP per cell and costs in the range of $1.5 million to just over $2.0 million.

Scaling up these cost from 2002 to 2007 at ~ 6% *per annum* [4.8] and adding ~7% for salt water make-up design changes [4.9] gives a range of $2.15 to $2.85 million.

4.1.5 Other Cost Elements

These cost and power ranges include only the tower itself from the inlet flange at (deck/ground) level, erected on a basin provided by others or at extra cost. There are additional costs which must be included to determine the total cost of the wet cooling tower as part of a complete plant cooling system. In addition, additional power must be included to account for the secondary circulation loop from the condenser exit to the top of the tower discussed in Section 4.4.1.

The most significant items are

- the cold water basin
- the circulating water system (lines, pumps)
- the electrical hookups and controls
- the auxiliary cooling system
- the make-up intake and blowdown discharge (if required) facilities.

4.1.5.1 Cold Water Basin

One of the vendors provided basin cost estimates separately, ranging from $26 to $31 per square foot. Most were between $29.50 and $30.80 per square foot. Here again, escalation to 2007 $ and additional costs for concrete resistant concrete and rebar protection will increase the estimate to perhaps $45 per square foot.

4.1.5.2 Circulating Water System

The cost of the circulating water system will be estimated as follows.

Circulating water lines—The circulating water lines are typically sized for a flow velocity of around 9 feet per second (Washington Group International 2001;Wheeler 2004) and evaluated at a cost based on inch-diameter and foot-length. (Washington Group International 2001) A value from the original report of $11/in-dia.-ft. length would increase under the previously discussed scaling laws to approximately $16/in.-dia.-ft. length.

It should be noted that this value is based on “greenfield” installation with relatively few interferences to trenching operations. These circulating water line installation costs can be enormously higher for retrofit projects as will be discussed in a later section.

Circulating water pumps—The pumping power will be calculated for the circulating water flow and the head rise required to overcome the height of the tower, the tube-side pressure drop across the condenser and a nominal allowance for the pressure drop in the lines. The pump/motor will be evaluated at $200/BHP. (Washington Group International 2001).

4.1.5.3 Electrical Hookups and Controls

Estimates from different sources in the course of several budget price requests were quite variable ranging from $25,000 to $50,000 per cell. An intermediate estimate of $35,000 per cell will be used for all cases. While this is an important cost element, it amounts typically to between 5% and 8% of the total tower system cost when the $35,000 per cell figure is used. The uncertainty in the estimate would be less than half that amount. Escalation to 2007$ suggests a reasonable cost estimate of $50,000 per cell.

Additionally, there may be circumstances where the plant electrical supply equipment may have to be upgraded to accommodate the power requirements for cooling tower fans and new circulating water pumps. A review of the reference case in the S&W report suggests that a typical allocation of these costs can run as high as 10% of the project costs.

4.1.5.4 Intake/Discharge Facilities

The cost of the make-up and discharge facilities is highly variable depending on site specific features and on whether the plant is a discharge site or a ZLD site even for new plants. In the case of retrofits, the approach may be to modify the existing intake/discharge structures for the much lower flows associated with closed-cycle cooling. In some cases this may be accomplished relatively inexpensively simply by closing off some of the flow area. In others, entirely new facilities may have to be constructed and the old ones may have to be demolished and removed, which could add significantly to the cost of the project. A recent estimate (Burns 2000) for a 750 MW combined cycle plant (~250 MW steam-side capacity) suggested a nominal cost of approximately $350,000 or $1,400/MW$_{steam}$. This value, if adopted and scaled to 2007$ would be approximately $2,000/MW$_{steam}$ or perhaps ~5% to 10% of the project cost. A review of the costs allocated to intake/discharge facilities in the S&W reference cases suggests a typical range of 1.5% to 3.% of project costs with occasional outliers as high as 8%. While the costs are important, even a substantial variability in the estimate would represent a relatively low uncertainty in the project cost.

4.1.5.5 Noise Reduction

One additional item, which can have a significant cost, is noise control. This might be accomplished with low noise fans, sound barriers, remote placement or some other approach. The need for noise reduction is highly dependent on site location. Other costs, including site preparation, painting, fire and lightning protection, acceptance testing and others, while often noted in cost estimating studies, are typically minor items.

These cost elements and the approach to accounting for them is summarized in Table 4-1.

Table 4-1
Capital Cost Elements for Wet Cooling Systems (Based On New Plant Construction)

Element	Comment	Cost
Wet cooling tower	Erected tower including structure, fans, motors, gear boxes, fill, drift eliminators, etc.	Dependent on heat load, materials of construction and design approach; See Figure 4-5a and related discussion.
Installation/erection	Included in base price	—
Surface steam condenser	Major cost element for new systems. Not included for most retrofits unless full re-optimization and new condenser is required (only for base load plants with long remaining life)	Typical range of \$7 to \$17/kWe; approx. 35 to 45% of system cost. Dependent on selected operating point; tradeoff vs. cooling tower is part of system re-optimization
Tower basin	Including typical site preparation; difficult geologic or soil conditions can increase cost.	Significant cost item; function of tower size; estimated at \$45/sq ft of basin area; typically 25 to 30% of tower cost
Electrical and control equipment	Fan/pump motor wiring and controls, etc.	Important cost item; estimated at \$50,000 per cell
Circulating water system	Pumps, piping, valves, etc.	Lines estimated at 9 ft/sec, \$16/in-ft; pumps at \$200/BHP.
Make-up intake and blowdown discharge structures	Included only for on-site intake/discharge facilities; site to remote source/discharge accounted for in cost of water	Estimated at \$2,000/MW_{steam}
Water treatment/blowdown discharge	Highly dependent on source water;	Minimal for seawater make-up and allowable NPDS discharge to ocean
Auxiliary cooling	Typically 5% additional heat load	Estimated at 5% of total system cost
Noise control	Highly variable but potentially significant; discussed in section on dry cooling systems	See associated discussion on dry systems.

Table 4-2
Additional Elements—Typically Minor and Site-Dependent

Element	Comment
• Site preparation/access provision • Winter operation; freeze protection • Painting • Fire and lightning protection • Acceptance testing	• Highly site dependent; likely minor; not likely to be affected significantly by system choice • Location dependent • Typically minor costs • Typically minor costs • Typically minor costs

4.2 Dry Cooling System Cost Elements

Dry cooling costs will be based on the use of direct dry cooling with an air-cooled condenser (ACC), as described in Section 3 and illustrated schematically in Figures 3-5 and 3-6. As was done for the wet cooling system cases, this discussion of dry cooling system costs is based on work reported by EPRI [4.3] Cost estimates were developed starting with budget cost estimates for the major components, in this case the air-cooled condenser, provided by major ACC vendors for a range of conditions. The specified design points are listed in Table 4-3.

The critical design variable for ACC's is the Initial Temperature Difference (ITD = $T_{cond} - T_{ambient}$) which is comparable to the approach temperature for wet cooling towers. Figures 4-6 and 4-7 display the ACC capital costs and fan power for the range of ITD's investigated in the EPRI study. Again, it should be noted that these are for a cooling system heat load of approximately 10^9 Btu/hour corresponding, as before, to about a 200 MW gas-fired steam plant.

Table 4-3
Example Dry Cooling System Design Points

	Case Study Descriptions				
	1	2	3	4	5
Climate Type	Arid, hot	Humid, hot	Arid, extreme	Moderate, cool	Moderate, warm
Met Data based on	El Paso, TX	Jacksonville, FL	Bismarck, ND	Portland, OR	Pittsburgh, PA
Design Steam Flow, lb/hr	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000
Design Backpressure, in Hga	2.5	2.5	2.5	2.5	2.5
Site Elevation, ft	10	10	10	10	10
Turbine Exhaust Moisture, %	5	5	5	5	5
Design Ambient, F	80	79	65	65	69
Design ITD, F	28.7	29.7	43.7	43.7	39.7

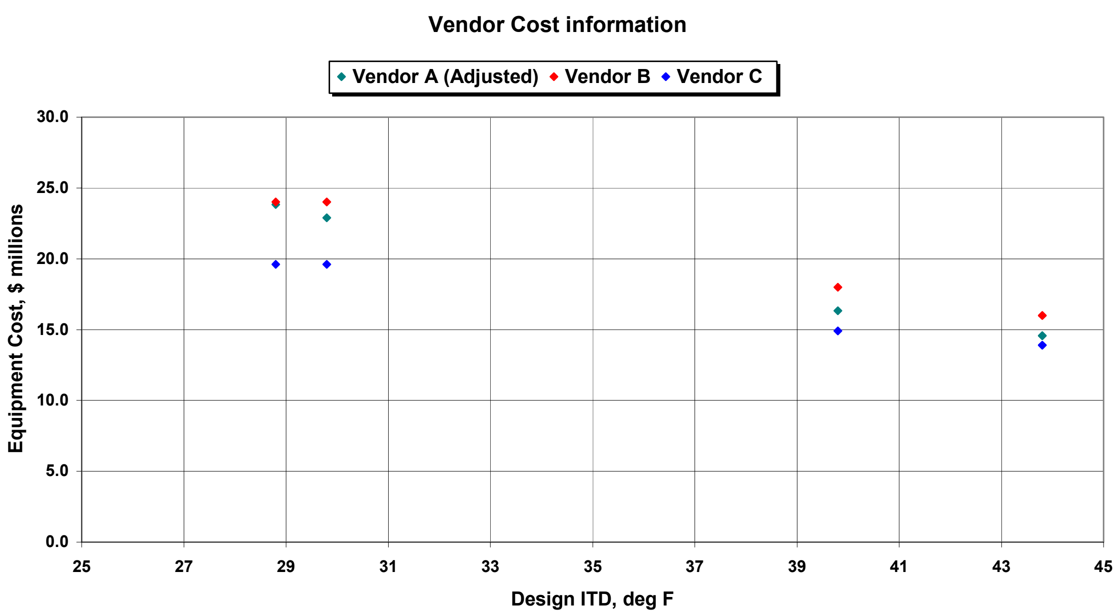


Figure 4-6
Air-Cooled Condenser Capital Cost Estimates (from Reference 4.3)

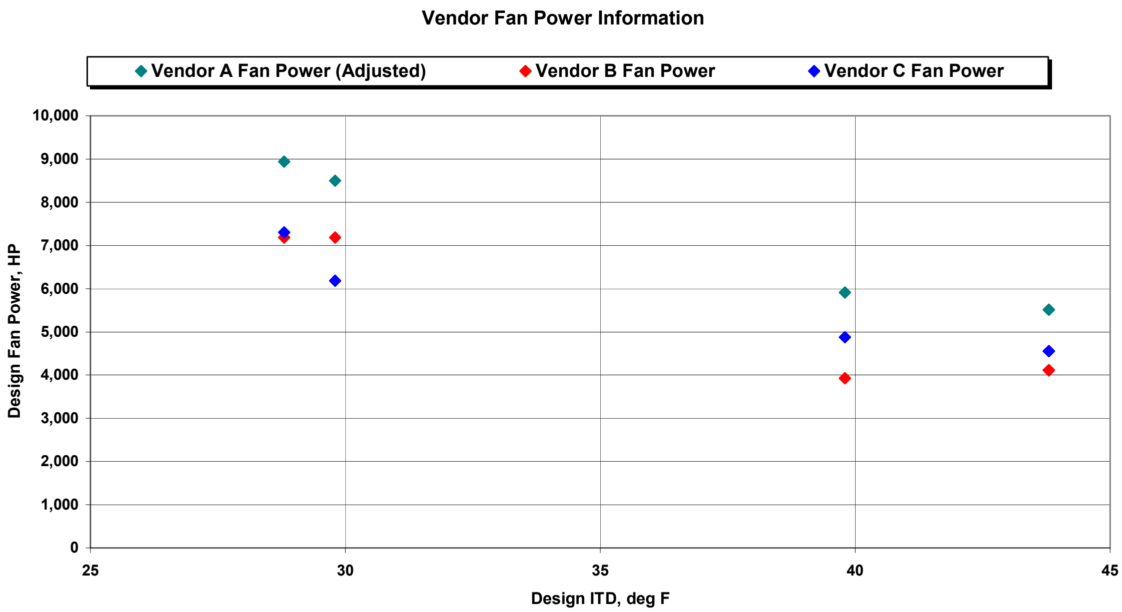


Figure 4-7
Air-Cooled Condenser Fan Power Estimates (from Reference 4.3)

While there is general agreement among the estimates, there are differences of approximately +/- 10% from the average in the costs and +/- 15-20% in the power. These differences can be partially, but not completely, explained by different trade-offs of capital costs against power costs.

As was done for the wet cooling tower, the costs may be scaled at approximately 6% *per annum* from 2002$ to 2007$. For a likely design ITD on the California coast of ~ 45°F (See Section 3.2.7) the capital cost of ~ $14. million from Figure 4-6 increases to between $18.5 and $19. million for an ACC heat load of ~ 10^9 Btu/hour. The expected fan power (Figure 4-7) is about 5,000 HP for a 30 cell configuration. ACC size and cost for a given ITD can be approximated by linear scaling with heat load as illustrated in Figure 4-8. Variations with ITD are non-linear increasing rapidly at lower ITD's.

The costs plotted in Figure 4-6 are *equipment costs only*. Normally, they include

- Finned tube heat exchanger elements
- Fans and motors
- ACC support structure
- Steam exhaust duct
- Piping and valves
- Air removal equipment
- Support for start-up, training, and testing.

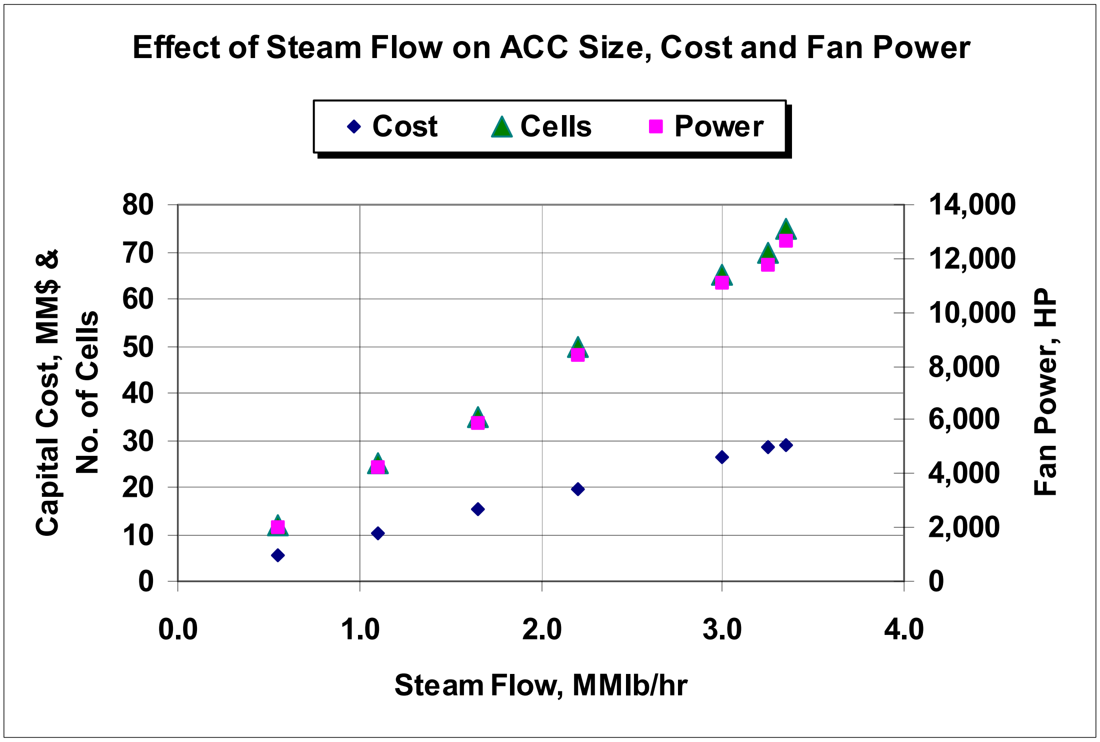


Figure 4-8
Variation in ACC Size, Cost and Fan Power With Heat Load

To these costs, a number of items, some of them major, must be added. Most important is the cost of delivery, erection and installation on site. Unlike wet cooling towers which are bid "erected", ACC equipment and erection costs are quoted separately.

In some cases, the erection is done by the equipment vendor and in other cases by independent erection contractors. The costs are highly variable depending primarily on local labor availability, rates and productivity, as well as geographic location and site topography. A general agreement emerged from conversations with vendors and architect-engineers that the erection accounted for approximately 30% of the sum of the equipment and erection cost (equivalent to about 43% of the equipment cost).

Other items not included in the base cost include site preparation, foundation supports, steam duct support structure, electrical hookups (control, switches, etc.), auxiliary cooling for other plant heat loads and fire and lightning protection. Optional items may include low noise fans and permanently installed cleaning equipment.

Additional costs (from Reference 4.4 and scaled to 2007$) were added for the steam duct support structure ($190,000 for the 1.1 MMlb/hr unit), the electrical hookups and controls (estimated at $40,000 per cell) and an allowance for auxiliary cooling (factored at 7.5% of the sum of equipment, erection, and electrical/controls costs).

Table 4-4 (from Reference 4.4) lists the major cost elements of a closed-cycle dry cooling system, assumed to be a direct system using a forced-draft air-cooled condenser (ACC).

Table 4-4
Capital Cost Elements for Dry Cooling System Equipment for New Facilities

Element	Comment	Cost
Air-cooled condenser equipment	See discussion in text	Strongly dependent on choice of design point expressed as ITD (T_{cond}-T_{amb}); ranges from \$130 to \$325/kWe
Installation/erection	Significant cost item; highly dependent on site location and topography	Estimated at 30% of total (equipment + erection) costs; Ranged from \$175,000 to \$225,000 per cell.
Steam duct support; column foundations	Installation dependent	Estimated for 10^6 lb/hr unit at \$160,000 to \$210,000; \$185,000 used for costs and comparisons
Electrical and control equipment	Fan/pump motor wiring and controls, etc.; see discussion in text	Important cost item; estimates ranged from at \$25,000 to \$45,000 per cell; used \$40,000 per cell.
Auxiliary cooling	Typically 5% additional heat load; typically handled with separate fin-fan unit or small wet cooling tower.	Estimated at 7.5% additional cost without specifying choice of auxiliary unit
Cleaning system for finned tube surfaces	Minor but required in most locations	Estimated at \$200,000
Low-noise fans	Base costs assume far-field sound pressure levels of ~65dBa at 400 feet; significant noise reductions can add 10 to 20% to base costs; see discussion in text	—

Table 4-5
Additional Minor Cost Elements

Element	Comment	Cost
• Water supply/intake structure	Minor (but not zero) for dry systems	Not included in cost estimates
• Water treatment/blowdown discharge	Minor (but not zero) for dry systems	“
• Site preparation/access provision	Highly site dependent and likely minor; not affected significantly by system choice	“
• Finish paint; fire/lightning protection	Typically minor costs	“

• Winter operation; freeze protection	Location dependent and relevant to both wet and dry systems; typically 2 to 4% of total installed cost; not included for California estimates	“

4.3 Cost Issues Related To Retrofits

Capital cost estimates for retrofit cooling systems were based on conditions reflecting “greenfield” costs for new plants. The construction and installation process is more difficult, time-consuming and costly when done on the site of an existing, operating facility with attendant interferences of existing structures, overhead and underground interferences and the on-going conduct of business. These additional costs are related to such items as:

- Branching or diversion of cooling water delivery systems,
- Reinforcement of retrofitted conduit system connections,
- Partial of full demolition of conduit systems and/or structures,
- Additional excavation activities
- Temporary delays in construction schedules[MSOffice1]
- Potential small land purchases
- Hiring of additional (beyond those typical for the “greenfield” cost estimates) equipment and personnel for subsurface construction
- Potential additional cooling water (recirculating or make-up delivery needs), and
- Expedited construction schedules and administrative and construction-related safety procedures.

All of these items add to the project costs but are very difficult to generalize. In future chapters, they will be discussed in the context of “degree of difficulty” for retrofits. Some other important cost items, which can be quantified more generally, are discussed below.

4.3.1 Use of Existing Circulating Water Piping Circuit

The ability to use existing circulating water piping is an important feature of minimizing the cost of retrofit. It depends on two factors: the ability of the existing piping to handle any increased pressure and the availability of a place to locate the cooling tower in reasonable proximity to the turbine hall and the existing condenser.

1. The need to pump the hot water from the condenser to the top of the tower imposes a higher pressure on the condenser tubes, the inlet and exit waterboxes and all piping from the circulating water pumps to the cooling towers. In many cases, neither the waterboxes nor the piping itself is designed to withstand this additional pressure, which might be an increase of 15 to 30 psi. In these cases, reinforcement or even replacement may be required at substantial additional cost.

2. At some sites, the only feasible place to locate a cooling tower may be quite far from the condenser and the existing inlet and discharge structures. There are also some sites that are so constrained that placement of a wet cooling tower is essentially impossible. Some studies have required the placement of the tower as much as one-half mile away, requiring the installation of 4000 to 6000 feet of new circulating water conduit.

4.4 Costs Other Than Capital Costs

The retrofitting of a plant designed for and operating on once-through cooling imposes a number of continuing costs on future operations of the plant in addition to the one-time capital cost of retrofit. The most important of these are

- *Additional operating power*: Recirculated cooling systems will have higher power requirements as compared to once-through systems for the increased head rise required of the circulating water pumps and for the fans to draw air through the tower. The power consumed for parasitic loads cannot be sold to the grid and represents lost revenue.
- *Additional maintenance costs*: Recirculated systems have additional equipment that requires maintenance labor and specialty chemicals costs for water treatment systems for both the make-up and the blowdown.
- *Additional fuel costs*: Plants equipped with recirculated cooling systems incur efficiency losses compared with once-through cooled systems due to the higher turbine backpressures imposed on the plant by limitations of the cooling system.
- *Potential for output capacity limitations*: To the extent that recirculated cooling system may not be able to maintain turbine backpressure below warranty limits during the hottest and most humid hours of the year, the plant maybe forced to reduce output to protect the turbine. While this is normally not the case with an optimized, well designed recirculated cooling system as applied to a new plant, the approach to retrofit which has been used in both the EPA and other cost analyses has chosen to reduce the initial capital costs by keeping the circulating water flow and the condenser the same as for the original once-through system. This results in a system that is far from optimum and may incur capacity limitations in some locations during the summer. This is a far more important consideration for dry cooling systems than for wet ones.

The following paragraphs provide a brief assessment of the possible magnitude of these costs.

4.4.1 Additional Operating Power

The major power costs are for the circulating water pumps and the fans. Consistent with the assumption used in the development of the capital costs, the power for pumping is based on the same circulating water flow as was used in the original once-through system. However, the head rise to be delivered by the pumps must be increased to pump the water to the top of the tower, perhaps 25 to 40 feet. This will increase the pumping power over the once-through system requirements by approximately 5 kW per MW. The fan power for a 170 MW steam cycle was determined in a recent study (M&D) to be approximately 7.5 kW per MW. This gives an additional operating power requirement of 12.5 kW/MW or 1.25% of plant capacity. If plume abatement towers are required, the pumping height increases to perhaps 60 feet or more. In some designs, a siphon effect can be used to ameliorate some of the additional head rise requirement.

Estimates in the SWEC report [4.5] for a single case study at a large nuclear plant indicated annual power requirements for pumps and fans of about 19,000 kW out of a gross electrical output capacity of 1,123 MW. If the original once-through system pumping power is subtracted the net increase is about 12,000kW or 1.07 kW/MW is essential agreement with the previous analysis. Both of these estimates exceed the allowance reported by EPA [4.1] of 0.85% of plant capacity (0.85 kW/MW).

4.4.2 Additional Maintenance Costs

The major parts of the additional maintenance costs are associated with the water treatment for make-up and discharge required for recirculated operation and, in some cases, the need to rebuild the tower after extended service. Both these costs are highly site and situation specific but some generalized estimates have been made.

1. A common rule of thumb (See, for example, Reference 4.6) sets the annual O&M costs at 1% of system capital cost. A case study for a large nuclear plant published in 1995 [4.10] found O&M costs not including power at about 1.6% of estimated capital costs.
2. EPA reports O&M costs on an annualized post-tax basis at $1,117 million for a capacity of 353,000 MW inclusive of the additional operating power. Using their estimate of 0.85% of plant capacity, the power costs would account for $720 million of that amount, if valued at $0.03/kWh. The remaining annual cost of $397 million is approximately 2.9% of the estimated capital cost.

4.4.3 Energy Penalty

The turbine backpressure achievable with a once-through cooling system is nearly always lower than that achievable with a recirculated cooling tower. To supply the condenser with the same flow of cold water at the same temperature as from a once-through system, the tower would have to cool the circulating water to the same temperature as the natural source water. The ambient wet bulb temperature is the lower limit for the achievable return water temperature for the tower. A reasonable tower design will do no better than approximately an 8-10°F approach (Approach = $T_{\text{cold water}} - T_{\text{wet bulb}}$). In addition, the ambient wet bulb is normally higher than the temperature of water withdrawn from natural sources (rivers, lakes, oceans) for much of the year, especially during the warmer, more humid months. For those times, the condenser inlet temperature and, as a result, the condensing temperature and the turbine backpressure will be higher than would have been the case with the original once-through cooling system. This backpressure elevation is most acute during hot, humid hours, which also correspond to times of peak electricity demand. The effect of increased turbine backpressure on plant performance is shown in Figure 4-9.

A more detailed discussion of the consequences of the energy penalty including increased air emissions is found in Section 7.2.1.

Increased heat rate results in higher fuel consumption for a given plant output. An increase in turbine backpressure of only 1 in. Hga would correspond to a fuel cost penalty of $1 million per year. This 1 in. Hga would occur with an ambient wet bulb temperature increase of only 10°F, which is well within the seasonal variability for most parts of the country. This estimate of a 1% energy penalty is in the mid-range of that estimated in a recent NETL study. [4.7].

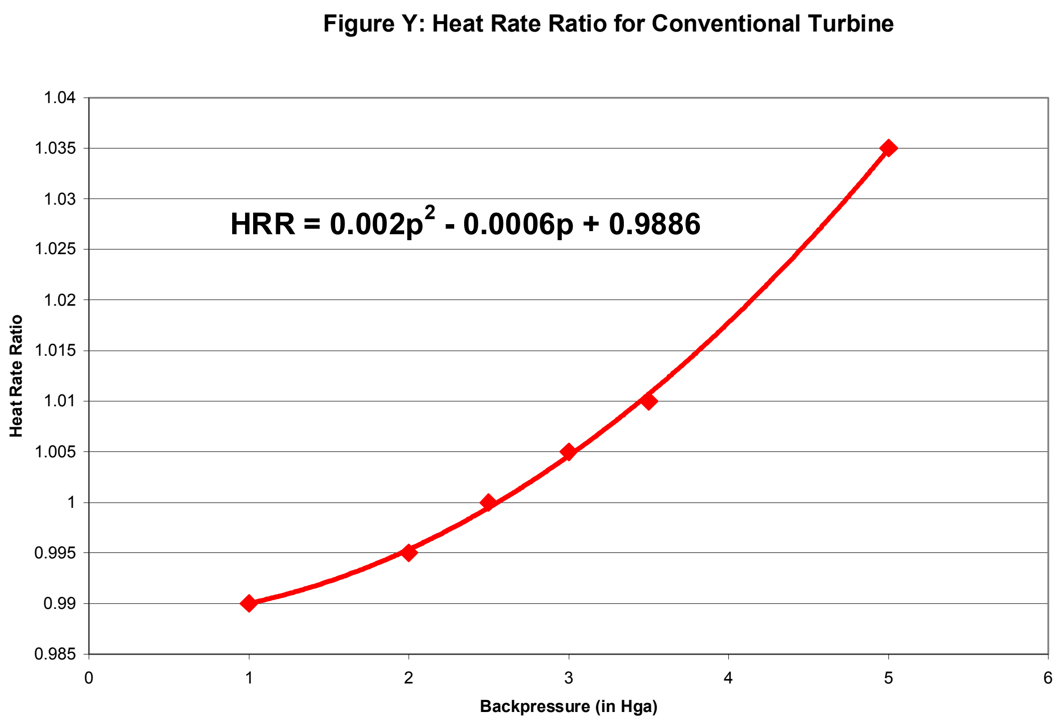


Figure 4-9
Effect of Backpressure on Heat Rate (Excerpted from Reference 4.4)

4.4.4 Potential Capacity Limitations

For older plants with conventional steam turbines, a backpressure of about 5 in. Hga may not be exceeded without risking damage to the turbine and possibly voiding any warranty that might still be in force. If the plant is "cooling system limited", it is possible that it will be unable to maintain acceptable turbine backpressure at full load during hot, humid hours. Therefore, under atmospheric conditions that would lead to higher backpressures, the plant may have to reduce steam flow and hence output to stay within allowable operating limits of the turbine. Since this capacity shortfall comes exactly at the time of peak demand and, in a competitive environment, at the time of highest energy price, the lost revenue can be substantial.

However, for a plant with a retrofitted recirculated cooling system designed to maintain 2.5 in. Hga backpressure at the 1% to 2% wet bulb temperature, such an occurrence is unlikely. An examination of the "extreme maximum" vs. 1% wet bulb temperatures in climatological data listings such as the AFOSR compilation [4.8] shows that such locations are rare. Therefore, it is reasonable to ignore potential capacity penalties for wet systems.

For dry systems, these limits are more frequently encountered although high temperatures are less extreme in coastal locations than elsewhere. However, each site will be reviewed briefly for possible hot day capacity limitations in the individual analyses.

4.5 References

4.1 Technical Development Document for the Final Regulations Addressing Cooling Water Intake Structures for New Facilities, (EPA-821-R-01-036), November, 2001.

4.2 Washington Group, International, "Estimated Cost of Compliance with EPA Proposed Rule 316(b) of the Clean Water Act", December, 2001.

4.3 *Cooling System Retrofit Cost Analysis*. EPRI, July 2002.

4.4 *Comparison of Alternate Cooling Technologies for U.S. Power Plants*. EPRI, August 2004. EPRI Report No. 1005358.

4.5 Yasi, D.E. and T. A. Adams, Engineering Cost Estimate for Retrofitting Cooling Systems at Existing Facilities", Stone & Webster Report to Hunton & Williams, July 3, 2002.

4.6 Burns, J. M. and W. C. Micheletti, "Comparison of Wet and Dry Cooling Systems for Combined Cycle Power Plants, Final Report (Version 2.1), prepared for Hunton & Williams, November, 2000.

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

4.8 Engineering News Record Construction Cost History Index

4.9 California Energy Commission, Performance, Cost and Environmental Effects of Salt Water Cooling Towers", PIER Report, In press.

4.10 Burns, J. M. *et al.*, The Impacts of Retrofitting Cooling Towers at a Large Power Station, Proceedings : Cooling Towers and Advanced Cooling Systems Conference, EPRI-TR-104867, February, 2005

5
COST ANALYSES

In recent years, a few studies have been conducted providing generic estimates of the cost of retrofitting once-through cooled plants to closed-cycle cooling. The emphasis in these studies has been on closed-cycle wet cooling rather than dry cooling, but some cost information is available for dry cooling using air-cooled condensers as well. In addition to the broader studies, a few site-specific analyses have been done which are available in the "grey" literature.

For wet system retrofits, this section will present in some detail the methodology and results from two of the generic studies and compared with examples from some individual studies. For dry system retrofits, some simplified design rules will be established, of particular relevance to conditions representative of the California coast, and cost/performance estimates will be developed and presented.

5.1 Generic Studies

The two generic studies to be discussed are the Stone & Webster (SWEC) study [5.1] and the Maulbetsch Consulting survey [5.2]. The two studies were done at the same time in 2002 in the context of the EPA 316(b) Phase II Rulemaking.

5.1.1 Stone & Webster Study

The report on the SWEC study was submitted to EPA as part of the comments on the rulemaking by the Utility Water Act Group (UWAG) and is available in the public record at http://www.epa.gov/waterscience/316b/phase2/comments/index.html under Hunton & Williams in the author index.

The SWEC developed a retrofit cost estimate for each of 1041 units that were operating with once-through cooling at the time of the study. The cost for each was scaled from one of six reference plants for which detailed cost estimates of a cooling system retrofit had been conducted in the past. These reference plants, listed in Table 5-1, cover a range of plant fuel, source water type and plant size. The total retrofit cost for each reference plant was aggregated in four categories as

- Labor
- Materials
- Equipment
- Indirects

To produce the estimate for each unit, SWEC chose the reference plant that was, in their judgment, most representative of the unit being estimated. The cost was then scaled from the selected reference plant using two scale factors:

1. The labor cost component was adjusted for regional differences in wages and productivity between the individual unit and the reference plant.
2. The adjusted total cost (adjusted labor plus materials, equipment and indirect) was then scaled from the reference plant to the individual unit on the basis of circulating water flow rate.

The assumption was made that the circulating water flow rate remained the same for the retrofitted system as it had been for the original once-through system. No modifications were made to the condenser. No attempt was made to adjust each estimate for local conditions other than labor costs or for site-specific "degree of difficulty". The cost estimates, because of the method used inherently reflected whatever local retrofit issues or difficulties pertained at the chosen reference plant.

The resulting costs were characterized by SWEC as "represent[ing] conservative 'low end' costs for cooling retrofit projects, not bounding site-specific costs." This was based on the fact that the case studies from which the individual unit costs were scaled all had

- sufficient land in close proximity to the condenser/circulating water system,
- no need for plume abatement and
- existing circulating piping that could be used in the circulating water system without reinforcement.

Additional costs, not included in the SWEC analysis but which can significantly increase site-specific costs include

- condenser modification and reinforcement
- reinforcement of circulating water piping
- extensive (or unusually lengthy) permit processes
- difficult construction environments such as saturated soils requiring dewatering or sites requiring extensive rock excavation
- potential labor and equipment shortages leading to delays and price spikes.

Figure 5-1 displays graphically the costs that would be generated by each of the reference plants for the range of circulating water flow rates and no adjustment of labor rates. With the exception of Plant X5, they are all within a relatively narrow cost range from $185/gpm to $212/gpm. Plant X5 represents a situation where relatively little work had to be done to upgrade the circulating water and make-up water systems.

A sample cost spreadsheet for one of the reference plants is displayed in Table 5-2 to indicate the various cost items included in each of the categories and to show how the indirect cost category was compiled.

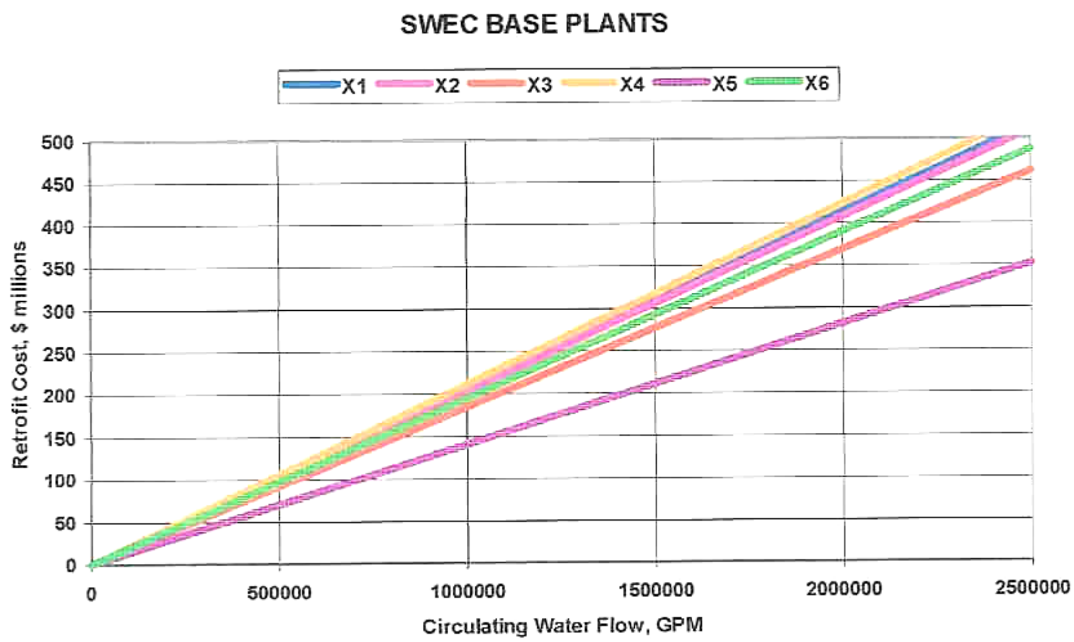


Figure 5-1
Scaled Costs from SWEC Reference Plants (from Reference 5.1)

Table 5-1
SWEC Reference Plants (from Reference 5.1)

Plant Code	Fuel	Water source	Capacity	Circulating Water Flow	Normalized Water Flow	Cost	Normalized Cost
			MW	GPM	GPM/MW	$	$/GPM
X1	Coal	Estuary	250	174,827	699	$36,000,000	205.9
X2	Coal	Esturary	650	279,403	430	$57,000,000	204.0
X3	Oil	Esturary	475	259,701	547	$48,000,000	184.8
X4	Ur	Esturary	900	570,448	634	$121,000,000	212.1
X5	Ur	Esturary	1250	895,522	716	$126,000,000	140.7
X6	Coal	River	Various	35,373		$6,900,000	195.1

Table 5-2
Allocation of Costs by Category (from SWEC Study)

PLANT IDENTIFER:	X3
RATED POWER:	475 MWe
COOLING SOURCE:	Estuary
RETROFIT COOLING TYPE:	Mechanical Draft Cooling Tower

Item #	Direct Costs	Labor Cost	Material Cost	Eng. Equip. Cost	Total Cost
1	Site Development	227,240	118,800	0	396,040
2	Plant Electrical	645,814	648,628	1,091,500	2,385,943
3	Yard Electrical and Security	557,888	291,900	20,000	869,788
4	Plant I & C	92,363	13,292	99,422	205,076
5	CW pumps,piping and valves	4,568,300	3,446,820	3,132,000	11,147,120
6	Cooling Tower	4,190,971	1,820,884	7,347,400	13,359,255
7	Circ Water Make Up Area	269,186	90,346	242,500	602,032
8	Circ Water Blowdown Area	64,138	22,065	0	86,203
9	Unit #4 Intake Structure	173,470	25,000	0	198,470
10	Cooling Tower Electrical Building	66,283	113,491	0	179,773
11	SWGR Building Cooling Tower	64,584	105,661	0	170,245
12	Load Centre Building	50,509	86,989	0	137,499
13	Cooling Pumps Sump Building	0	0	0	0
14	Acces Road and Bridges	164,186	134,086	0	298,272
	Total Directs	**$11,134,932**	**$6,917,962**	**$11,932,822**	**$30,035,716**
15	Labor-overtime				1,118,493
16	Labor Productivity				2,236,986
17	Escalation-Labor				671,096
18	Escalation-Materials				190,244
19	Escalation - Engineered Equip				178,992
20	AFI				3,443,153
21	Indirects				189,373
22	Constuction Supervision				856,441
23	Engineering/Design				3,839,268
24	Spare Parts,First Fills,etc				20,000
25	Tranportation				754,031
26	Warranty				94,254
27	Contigency				4,362,805
	Total Non-Directs				**$17,955,136**
	Total Estimated Cost				**$47,990,852**

Site-specific factors were emphasized to have a significant effect on project costs. A number of factors discussed included:

- Re-optimization (and hence complete replacement/reconstruction) of the entire cooling circuit
- Consideration of natural-draft, as opposed to mechanical-draft, cooling towers in large, baseload plants with high capacity factor and long remaining life
- Removal and replacement of the existing condenser
- Removal, replacement or reinforcement of existing circulating water lines

- Inclusion of very long recirculating water lines to accommodate tower sitting difficulties
- The encountering of numerous interferences at existing pants during the installation of all new water lines
- Upgrading of water treatment, chlorination and de-chlorination systems
- Replacement or modification of existing intake/discharge structures, possibly including demolition of existing structures
- Site geological considerations such as groundwater pumping, rock excavation or the requirements for extensive piling supports for towers
- Installation of a separate electrical/power system
- Special corrosion resistant materials depending on source water characteristics.
- Possible equipment and labor shortages and associated schedule delays, price increases, etc.
- Licensing and permitting issues depending on the proximity of residential areas, special facilities such as schools, recreational areas, hospitals or other sensitive receptors, or transportation facilities such as airports or highways

All of these factors were noted to be commonly encountered in SWEC experience at power plant projects.

5.2 Maulbetsch Consulting Survey

The report on the Maulbetsch Consulting survey was submitted to EPA as part of the comments on the rulemaking by EPRI and is also available in the public record at http://www.epa.gov/waterscience/316b/phase2/comments/index.html under EPRI in the author index.

Cost estimates for retrofitting once-through cooling systems to recirculated systems were solicited from many utilities including EPRI and Utility Water Act Group (UWAG) member companies. In addition, a brief literature search was conducted for published studies. Cost information was obtained for 50 plants. These were grouped by fuel type (nuclear or fossil), plant size (> or < 500MW) and source water type (fresh, brackish or saline). Table 5-3 gives the distribution of the plant data among the categories.

Table 5-3
Distribution of Fifty Plants With Retrofit Cost Information

Distribution of Plants by Type, Size and Source Water (from Reference 5.2)			
Nuclear (15)	**Saline**	**Brackish**	**Fresh**
> 500 MW (15)	5	5	5
< 500 MW (0)	0	0	0
Fossil (35)	Saline	Brackish	Fresh
> 500 MW (29)	2	8	19
< 500 MW (6)	1	1	4

The source information came in varying forms and some adjustments were often required to put them on a common basis. The two most important considerations were the year in which the estimate was made and whether or not ancillary costs, such as indirects, project management, contingencies and others, were included in addition to the direct costs.

In all cases, the year in which the estimates were made was reported. The dates of the estimates ranged from 1973 to 2002. For estimates made in years prior to 2002, the values were scaled up to 2002 dollars using the appropriate multiplier from the Engineering News Record's Construction Cost Index (ENR-CCI), available at http://enr.construction.com/cost/costcci.asp. The increase over the previous ten years at that time was equivalent to a compound escalation rate of 2.8%. In a few instances, the utility supplying the data provided a separate estimate of updated costs from original earlier estimates. These were generally close to, but not necessarily identical to the factor that would be derived from the ENR-CCI. In those cases, the utility estimate was used on the basis that it might better reflect local circumstances.

The information provided for the cost of retrofit at a particular plant varied from a "single number estimate" to fully documented engineering studies. Two important questions for the "single number estimates" were:

- What was the extent of the retrofit?
- What ancillary project costs were included?

"Extent of retrofit" refers to whether or not the plant cooling system was re-optimized to account for the different operating characteristics of a recirculated system as was discussed in Section 4. With only two exceptions, the cost information for all 50 plants obtained in the survey was for "retrofits in which the condenser and the circulating water flow was the same as for the original once-through cooling system and the closed-cycle retrofitted system was *not* re-optimized.

5.2.1 Ancillary Costs

The fully documented studies presented direct cost items including purchased equipment and installation costs. Table 5-4 displays a listing of typical cost elements, taken from a published study of retrofit cost estimates for a large nuclear plant [5.3] In addition, ancillary cost elements are added in order to develop a realistic "total project cost". One such set of cost categories is listed in Table 5-5, taken from a study of the Millstone Plant presented to the Connecticut Department of Environmental Protection [5.4] These costs are normally "factored" or estimated as a percentage of the Direct Costs. The percentages used in the Millstone study are given in Table 5-5. Based on these values, the ancillary costs add 37% to the Direct Costs of the retrofit.

Other studies include similar adjustments to the Direct Costs. Regardless of the exact categorization, the total adjustment ranged from 35% to 45% in the case of one utility study.

In interpreting the "single number estimates" received for individual plants, it was not clear whether the cost represented the Direct Cost or the total project cost. Telephone inquiries to all sources that could be reached indicated that in most (but not all) cases the total project cost was included but it was seldom known what percent of the total was represented by the ancillary costs. In cases where it was determined that only the direct costs had been reported, the cost was increased by 40% to put it on a consistent basis with the rest. For cases where it could not be determined which costs were reported, it was assumed that the reported cost was the total project cost.

Table 5-4
Retrofit Cost Elements

Typical Cost Elements for Recirculated Retrofit (from Reference 5.4)	
Major Elements	**Minor Elements (each < 0.5%)**
Cooling Tower	Plant I & C
Circulating water pumps	Site development
Plant electrical	Cooling tower electrical building
Yard electrical	Switchgear
Return pump structure and flume	Load center building
Cooling tower pump structure and flume	Cooling tower pump building
Transportation	Access roads
	Sound wall

Table 5-5
Ancillary Cost Elements

Typical Ancillary Costs	
Cost Category	**% of Direct Cost**
Construction Management	7
Engineering	10
AFI*/Contingency	20

* *A*llowance *f*or *I*ndeterminates

Figure 5-2 displays the results of the survey. The retrofit costs are plotted in 2007 dollars. The grouping into categories "Easy", "Average" and "Difficult" is somewhat arbitrary but generally; represents points over a range of circulating water flow rates which cluster around a similar normalized cost factor if $/gpm. The "best fit" line for the "Difficult" category is heavily influenced by a few very high cost projects.

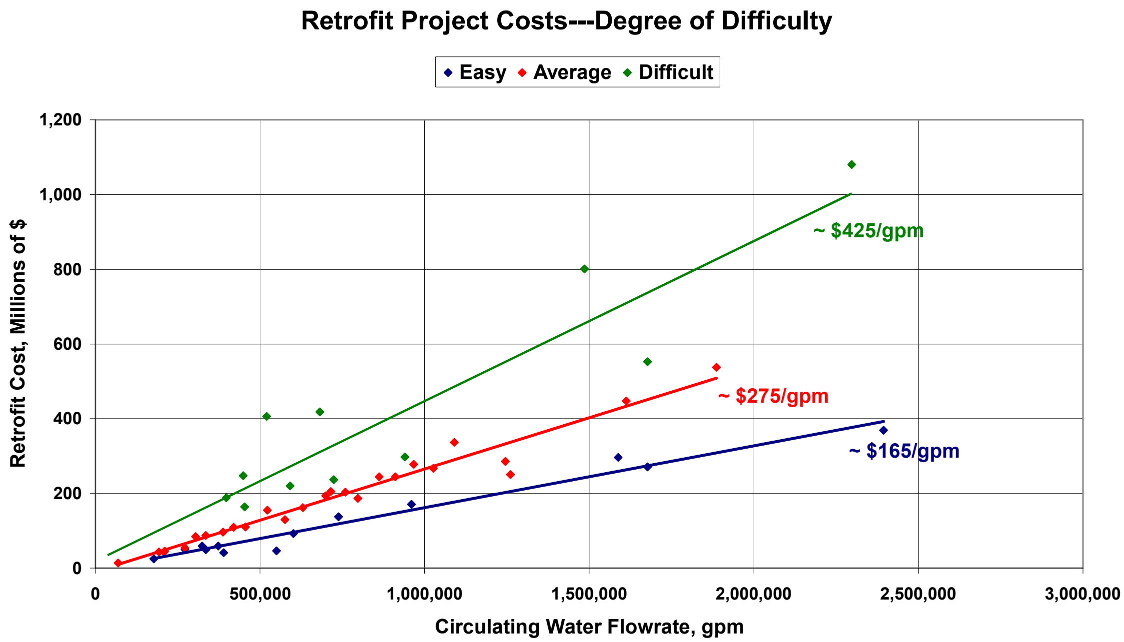


Figure 5-2
Survey Project Costs Grouped by Degree of Difficulty

5.3 Some Comparisons

Figure 5-3 displays comparisons to the individual plant case study data with the results of the SWEC estimates. These estimates give excellent (+/- 25%) agreement against approximately 2/3 of the individual plant data and reasonable agreement (-25%/+50%) for all but about 20% of the cases. A few points are substantial outliers exceeding the estimates by a factor of 2 or more.

It is noteworthy that most of the deviation is in the direction of underestimating the individual plant costs rather than overestimating. In fact, the data cluster itself has a reasonably well-defined lower bound while discontinuities and outliers characterize the high cost boundary. This is consistent with the notion of a reasonably well-defined “minimum cost retrofit” (such as might be represented by new facility construction) modified by site-specific differences that lead to a range of high-end costs that are not predictable on the basis of simple scaling laws.

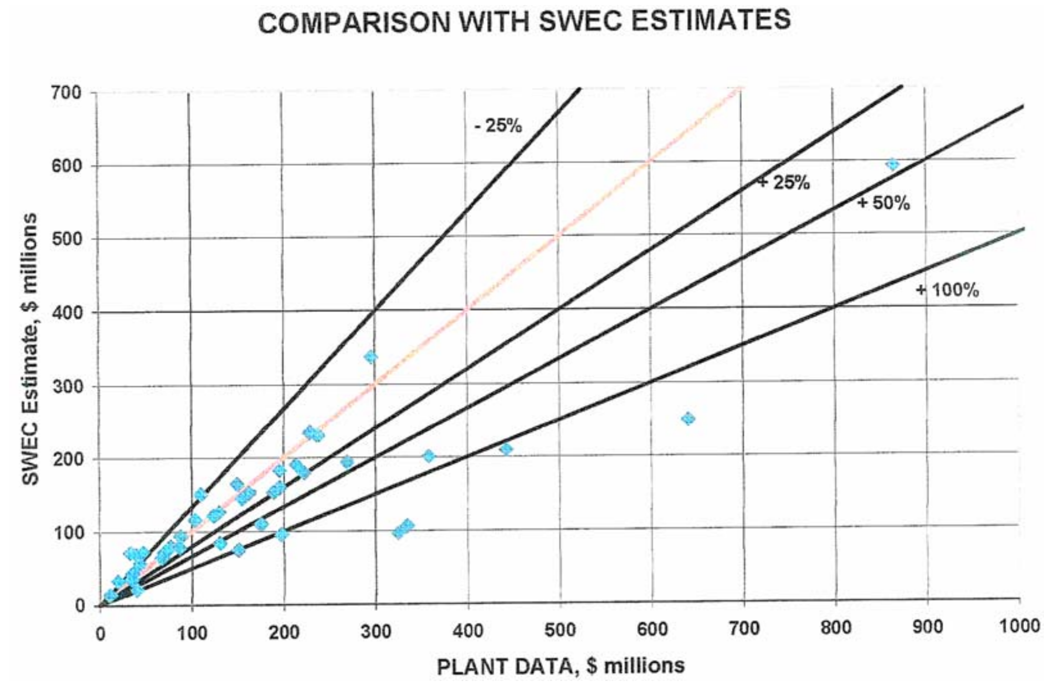


Figure 5-3
Comparison of Survey Data With SWEC Estimates

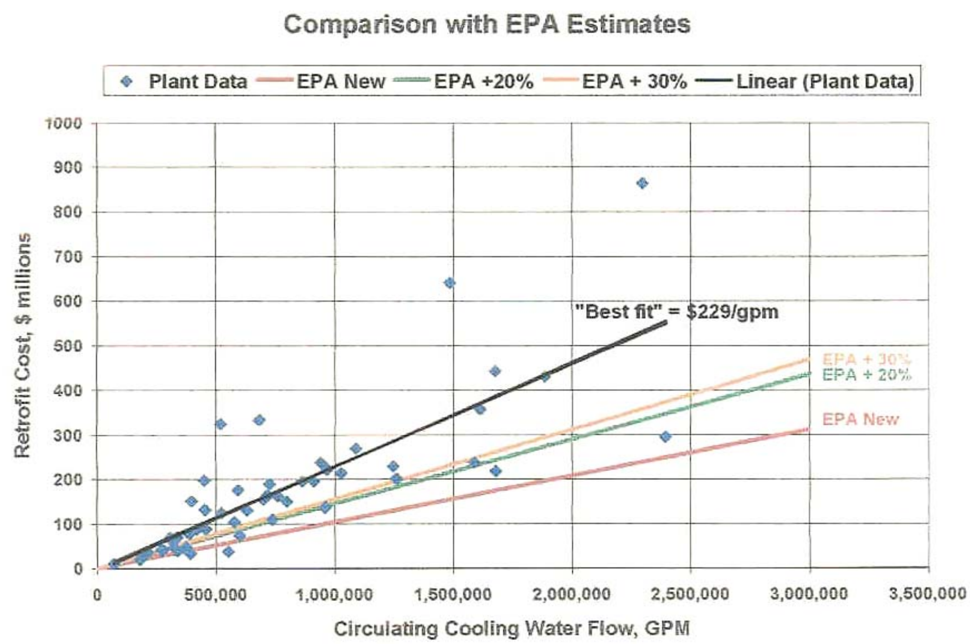


Figure 5-4
Comparison of Survey Data With EPA Estimates

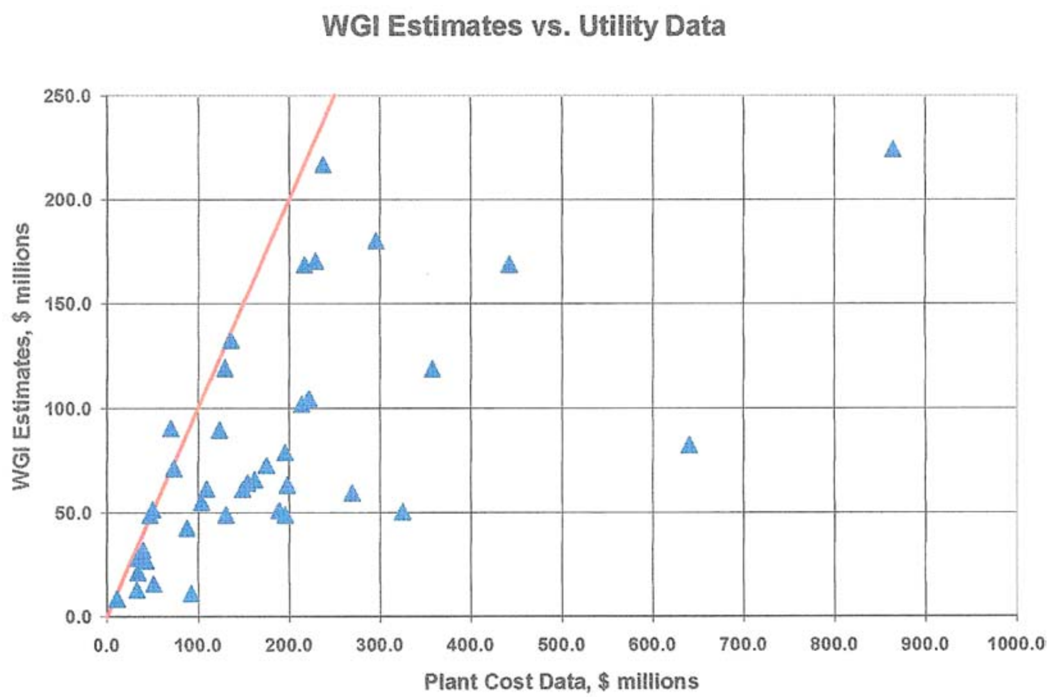


Figure 5-5
Comparison of Survey Data With Washington Group Estimates

The general conclusions to be drawn from these analyses is:

- New plant costs are well established and can be consistently estimated
- A majority of retrofit projects can be characterized as being of "average" difficulty
- These costs exceed the cost of new facilities, even when those cost are "factored" with modest increases to account for the nature of retrofits, by a factor of 1.5x to 2x.
- A significant portion of projects, conducted under more difficult circumstances exceed the lower bound costs by at least a factor of 2.5x and exceed the "average" cost estimates by at least 1.5x and sometimes as much as 3x.

5.4 Estimates for this Study

The primary purpose of this study was to set forth a methodology for assessing the level of difficulty to be expected for cooling system retrofit projects at any particular site. This included identifying all the elements of a retrofit and all the features of a site which would make the retrofit more or less difficult and costly. Then each site was reviewed on the basis of information provided by the plants including both operating and site characteristics.

The operating profiles included:

- Plant output including seasonal variations and capacity factors
- Cooling system design and flow data
- Condenser design and construction details

- Turbine heat rate characteristics

Site characteristics included:

- Source water temperature data (seasonal variation)
- Meteorological data (average, extreme and annual variability)
- Site plans
- Underground utilities/interferences diagrams
- Characteristics of the surrounding neighborhood
- Alternate cooling water sources
- Local regulatory issues

This information was available in varying degrees of completeness from site to site. For each site, a simple conceptual design for both a wet and dry cooling system was constructed and the performance and power requirements estimated. The results of the estimates were compared to the estimated or reported performance of the plant's once-through cooling system. Qualitative estimates of the site characteristics were used to estimate when the retrofit would encounter requirements or problems which would increase the difficulty and cost of the project.
From these considerations, a cost range was estimated for each site.

5.5 Additional Cost Analyses

In order to better understand the effect of site and operating characteristics on the cost, two simple analyses were conducted in addition to the application of the results of the previous studies discussed in the earlier sections. These consisted of simple cooling tower parametric design studies and a simple construction cost spreadsheet based on other studies. The intent was primarily to determine the sensitivity of total retrofit cost to variations in the cost of individual project elements.

5.6 References

5.1 Yasi, D. E. and T. A. Adams, Jr., Engineering Cost Estimates for Retrofitting Recirculated Cooling Systems at Existing Facilities, Stone and Webster Report to Hunton & Williams, July 3, 2002. (Available at http://www.epa.gov/waterscience/316b/phase2/comments/index.html in Author Index under Hunton & Williams).

5.2 EPRI, Cooling System Retrofit Cost Analyses, EPRI Report No. ??, July 26, 2002, Submitted to EPA as Comments on 316 (b) Rulemaking, August 26, 2002. (Available at http://www.epa.gov/waterscience/316b/phase2/comments/index.html in Author Index under EPRI).

5.3 Burns, J. M. *et al.*, *The Impacts of Retrofitting Cooling Towers at a Large Power Station, Proceedings of Cooling Tower and Advanced Cooling Systems Conference*. February 1995. EPRI-TR-104867.

5.4 Millstone Power Station: An Evaluation of Cooling Water System Alternatives, Submitted by Dominion Nuclear Connecticut, Inc. to Connecticut Department of Environmental Protection, August, 2001.

6
COST RANGES

This section presents the results of the SWEC study as well as the results of applying the “easy”, “average” and “difficult” correlations from the Maulbetsch Consulting survey to the California coastal units.

6.1 SWEC Cost Estimates

The methodology used by Stone and Webster Engineering Company in their 2002 study for the Utility Water Act Group (UWAG) was described in detail in Chapter 5. Table 6-1 displays the results of scaling these results from the original report up to 2007$ and adjusting the escalated costs to account for seawater makeup using Huntington Beach Unit #1 as an illustrative example.. The results of this scaling procedure for all plants and units of interest to this study are given in Appendix A.

The labor costs are escalated at 3% for five years. Equipment and Materials costs are escalated at 6% for 5 years. These escalation rates are intended to be consistent with published values in a variety of trade association journals. While they may not accurately reflect local conditions in all cases, the variability will not have a dominant effect of the total costs. The Indirects are held at the same percentage (~58%) of direct costs that SWEC used in the original study.

Finally, based on the results of a study of salt water cooling tower cost/performance characteristics [6.9], the total costs were increased by 7% to account for the effects of seawater make-up on cooling system performance, design and materials of construction in accordance with the results of a salt water cooling tower study conducted in 2006 [6.1].

Table 6-1
SWEC Cost Estimate Adjustments

Adjustment of S&W Costs (Huntington Beach Unit #1)					
Amounts	**Labor**	**Materials**	**Equipment**	**Indirects**	**Total**
2002 $	$4,720,000	$2,380,000	$4,050,000	$6,440,000	$17,590,000
2007 $	$5,472,000	$3,185,000	$5,420,000	$8,164,000	$22,241,000
x 1.07 for high salinity	$5,855,000	$3,408,000	$5,799,000	$8,736,000	$23,798,000

6.2 Maulbetsch Consulting Survey Cost Ranges

A survey of retrofit costs from 50 plants conducted in 2002 by Maulbetsch Consulting was described in detail in Section 5. The results, as displayed in Figure 5-2, provide three scaling factors based on circulating water flow rate for “Easy”, “Average” and “Difficult” retrofits.

The factors are

Easy: $165/gpm
Average: $275/gpm
Difficult: $425/gpm

Again using Huntington Beach Unit #1 as the illustrative example, the circulating water flow is 84,000 gpm. Applying the same factor of x 1.07 to account for seawater make-up, the corresponding costs are:

Easy: $14,830,000
Average: $24,717,000
Difficult: $38,199,000

While the range is quite large, the "Average" difficulty cost is quite close to the SWEC estimate.

6.3 Additional Comparisons

6.3.1 Huntington Beach

Two additional estimates are available for units at Huntington Beach. One of these was done by Sargent & Lundy (designated as "S&L" in Figure 6-1) for Huntington Beach directly in 2005 [6.2]. The other, designated as "This study" in Figure 6-1, was done as part of this current study, as described briefly in Section 5.5, using cost estimating factors from previous studies of the costs of mechanical draft wet cooling towers [6.3 and 6.4] and others obtained from analyses of information collected from several sources as part of the 2002 survey [6.5]. The comparative results from all sources are shown in Figure 6-1. For the SWEC and Survey values, the Unit #1 costs above were multiplied by x 4 to provide a "plant-level" cost.

The results show reasonable agreement between scaled estimates, specific studies and survey results for projects of "Average" difficulty. This does not mean that any of these costs would correspond to the actual cost of retrofit at this site. A careful analysis of the sort that would be done in preparation for bidding an actual project might identify either features of the site that would lead to higher costs or opportunities for cost savings that would reduce the costs. In the course of an actual retrofit, other conditions might be encountered which would change the actual costs from these estimates. However, for the level of detail and precision that can be achieved in this study, it appears that the use of the SWEC results coupled with the survey results will provide a reasonable idea of the likely costs.

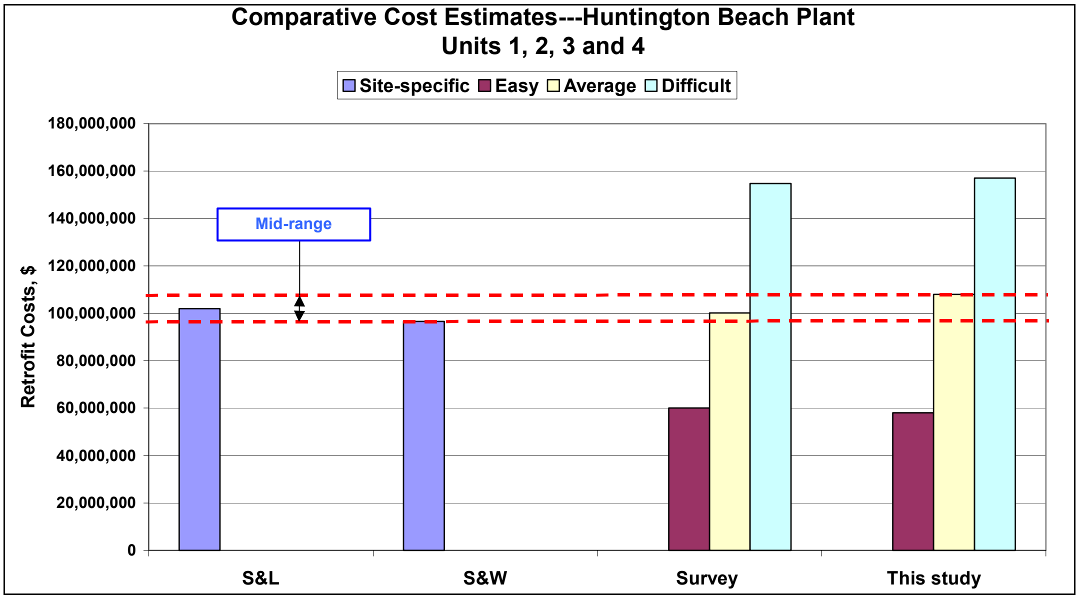


Figure 6-1
Comparison of Cost Estimates for Huntington Beach

6.3.2 Diablo Canyon

Although Diablo Canyon was not included as one of the plants in this study, information from prior investigations is available in the public record. These include the Stone & Webster study [6.6], and two site-specific studies by TetraTech [6.7] and Burns Engineering [6.8]. In addition, the correlations developed in the Maulbetsch Consulting survey can be easily applied as discussed in Section 4.

The SWEC estimate falls between the "Easy" and "Average" estimates from the survey, somewhat closer to the "Easy" value and well below the "Difficult" level. It is noteworthy, however, that the two studies in which experienced engineering organizations conducted detailed, in-person inspections and analyses of the site, both estimates were well in excess of even the "Difficult" level from the survey. A review of the reports on these studies shows that both identified features of the site requiring extensive condenser modifications, site preparation, building modification and relocation and upgrading of cooling system support facilities that are not normally captured in generalized estimating methods even when based on actual experience at "reference" sites.

6.3.2.1 Cost Estimates for California Coastal Plants

The comparisons of the SWEC and survey costs for each of the California coastal plants are given in Figures 6-2 through 6-5. Figure 6-6 sums the costs for all of the coastal plants together. Appendix B contains in-depth discussions of the results for each individual plant which identify features of each that would tend to categorize the plant as more or less difficult than "average" along with a discussion of the "non-economic" issues for each plant individually.

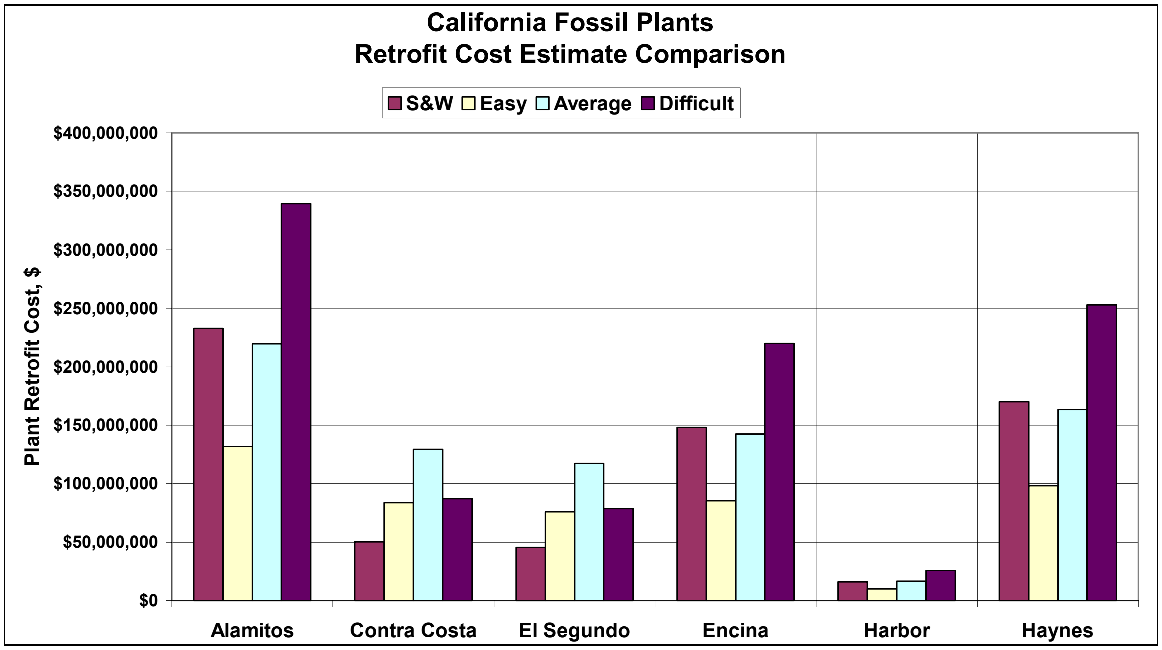


Figure 6-2
Cost Estimates for California Coastal Plants

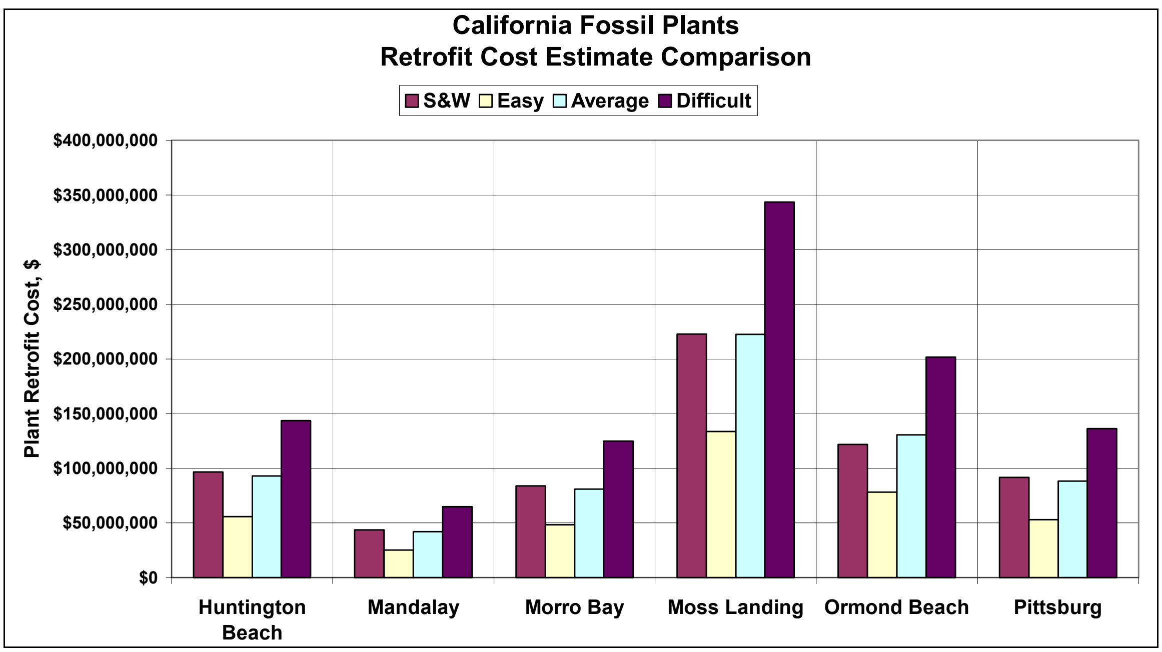


Figure 6-3
Cost Estimates for California Coastal Plants

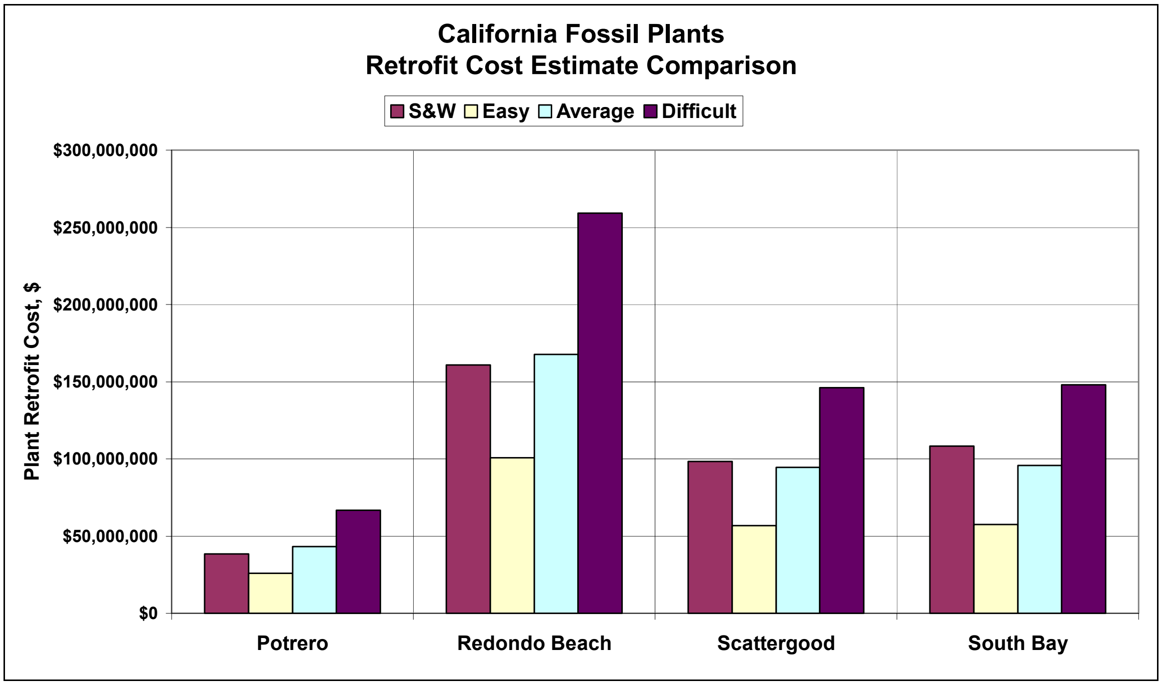


Figure 6-4
Cost Estimates for California Coastal Plants

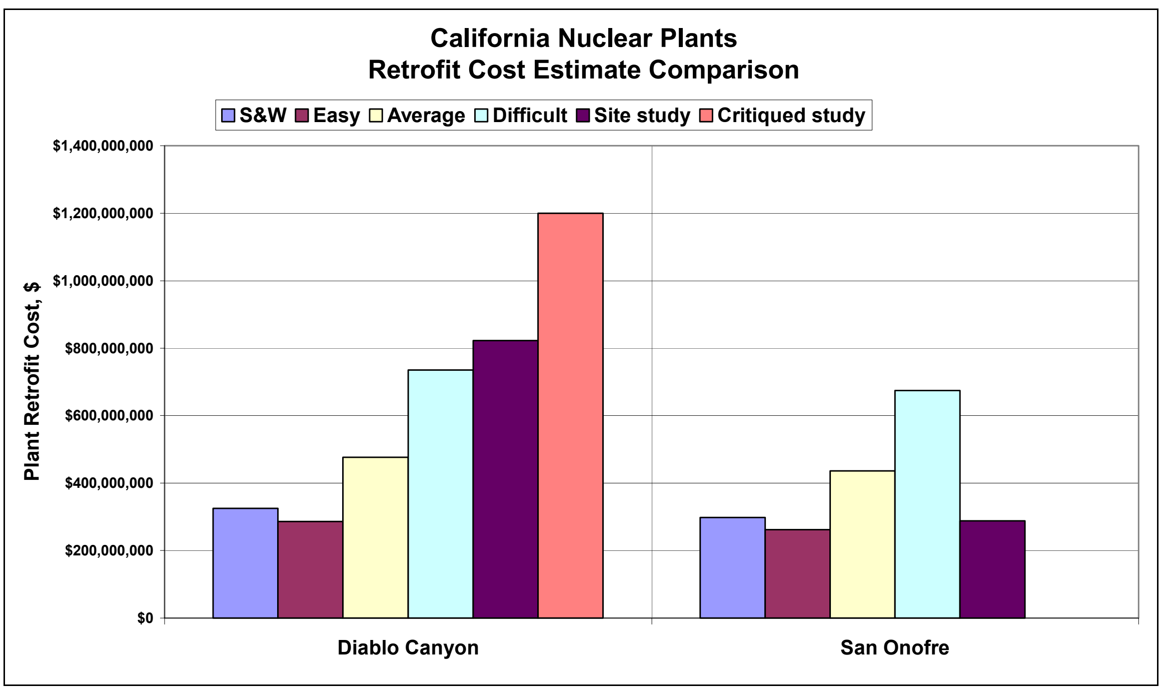


Figure 6-5
Cost Estimates for California Nuclear Plants

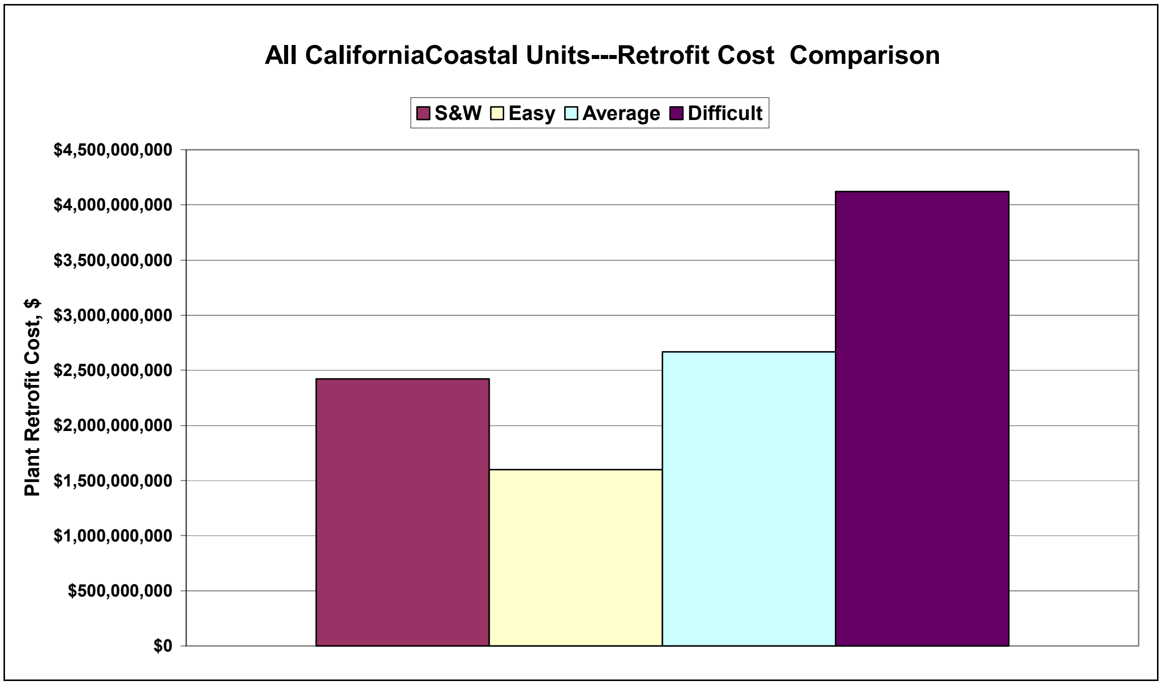


Figure 6-6
Coastal Plant Totals

6.4 References

6.1 California Energy Commission, Performance, Cost and Environmental Effects of Salt Water Cooling Towers", PIER Report, In press.

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6.3 California Energy Commission, "Comparison of Alternate Cooling Technologies for California Power Plants; Economic, Environmental and Other Tradeoffs", PIER Report No. P500-02-079F, February, 2002.

6.4 *Comparison of Alternate Cooling Technologies for U.S. Power Plants.* EPRI, August 2004. EPRI Report No. 1005358.

6.5 *Cooling System Retrofit Cost Analysis*. EPRI, July 2002.

6.6 Yasi, D.E. and T. A. Adams, Engineering Cost Estimate for Retrofitting Cooling Systems at Existing Facilities", Stone & Webster Report to Hunton & Williams, July 3, 2002.

6.7 TetraTech, Inc., "Evaluation of Cooling System Alternatives, Diablo Canyon Power Plant", November, 2002.

6.8 Burns Engineering Services, Inc., "Feasibility of Retrofitting Cooling Towers at Diablo Canyon Units 1 and 2", April, 2003.

7
OTHER CONSIDERATIONS

The impetus for considering converting once-through cooling to closed-cycle cooling derives from a desire to reduce any environmental harm resulting from the withdrawal of large quantities of water from natural water bodies into a power plant. Section 316(b) of the Clean Water Act requires that the "location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." EPA adopted regulations for new and existing facilities to ensure that cooling water intakes are "designed to protect fish, shellfish and other aquatic life from being killed or injured". To achieve this, reductions in entrainment and impingement mortality of varying percentages were established. While these might be achieved in a variety of ways, it is generally conceded that, if the intake flow is reduced to a level consistent with closed-cycle cooling, the requirements would be considered to be met.

As noted in Section 1, the regulations for new plants were promulgated on December 18, 2001 and were based on closed-cycle cooling since nearly all new plants now use closed-cycle wet or dry cooling systems. The rule for existing plants was issued on July 9, 2004 and did not require closed-cycle cooling but noted that conversion to closed-cycle cooling, if chosen, would satisfy all requirements. The rule has since been remanded by the 2nd Circuit Court on January 25, 2007 and suspended by EPA. The guidance from EPA to their Regional Offices has been to exercise, in the absence of a revised rule, "Best Professional Judgment" (BPF). It is anticipated that EPA Regions and States, including California will administer Section 316(b) through NPDES permits on a BPJ basis until the Court Decision issues are resolved through further litigation and/or a rulemaking to address remanded portions of the Rule.

The focus 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. One of the issues remanded to EPA by the Court was clarification as to the basis for not designating closed-cycle cooling as Best Technology Available in the Phase II Rule. The Court Decision indicated that any consideration of the monetized environmental benefits relative to use of closed-cycle cooling in a cost-benefit analysis was unlawful. However, the Court indicated there were three factors that could be considered relative to the determination that included:

- Can industry reasonably bear the cost of closed-cycle retrofits
- Impacts to energy production and efficiency
- Adverse environmental impacts associated with closed-cycle cooling

In this Chapter summary information is provided relative to these considerations as well as other social impact considerations.

7.1 Economic, Energy Production and Efficiency Considerations

Analyses of 18 individual plants on the California coast have dealt with the issues of cost, efficiency and capability of power production and illustrated the very site-specific nature of these issues. Descriptions of each of these analyses are assembled in Appendix B. Some conclusions and generalizations from these analyses are summarized below.

- Retrofit costs for individual plants vary widely from $30 million to $230 million due to the range in the size of and number of once through cooling units.
- The total estimated capital cost for all 18 plants is estimated to be between $3.6 and $4.2 billion. This estimate does not include additional costs which will be inevitably incurred as part of retrofit projects including increased operating and maintenance costs for the remaining life of the plants, revenues lost during outages required by the retrofit projects and associated permitting costs.
- Closed-cycle wet cooling, while theoretically possible at most sites, was judged to be of a high degree of difficulty and cost at 9 of the 18 plants studied due primarily to severe space constraints and to the impracticality of making major capital investments at facilities with low utilization.
- Retrofitting to dry cooling was judged to the infeasible at all plants due primarily to the unsuitability of older turbines designed for once-through cooling for operation at the elevated backpressures imposed by dry cooling.
- Major factors influencing the costs, in addition to simply the size of the plant include the type of plant, the character and crowdedness of the surrounding neighborhood, the availability of open space on or adjacent to the site, the design of the existing turbine, condenser and circulating water system and the regulatory requirements pertinent to the plant location.
- Most of the plants are older facilities with low capacity factors and limited remaining life as shown in the figure below. In spite of this, these plants do operate in times of peak demand, typically in the summer where past years have seen serious power shortages on some occasions.

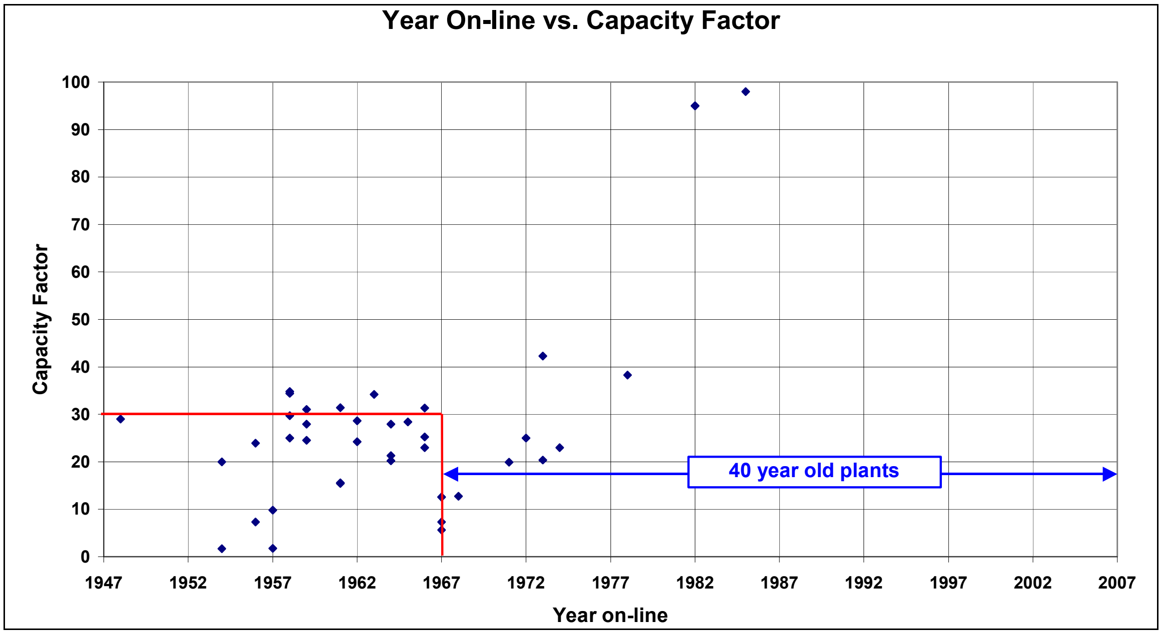

Figure 7-1
Year On-Line and Capacity Factor of California Coastal Plants

- Old age, low capacity factor and limited remaining life can result in a high capital cost for retrofit being disproportionate to the plant's ability to recover such an investment through future operating revenue.
- If plants older than 40 years and with capacity factors less than 30% (indicated in the red box on the figure above) were to retire the generating capacity in California would be reduced by 10,250 MW or approximately 15% of the installed in-state capacity.

If retrofits were required at older facilities with low capacity factors, such a facility would presumably conduct a financial analysis to determine the effect of conversion to closed-cycle cooling on the future economic viability of the facility. As noted above, retirement of a significant fraction of these facilities has the potential to adversely affect the energy supply situation in the State, particularly with regard to their role as peaking plants and the State's ability to meet peak demand.

7.2 Adverse Environmental Effects

All cooling systems have some effect on the environment. As noted above, the driving concern for once through cooling systems is the effects on fish, shellfish and other aquatic life from intake losses and the thermal discharge. The degree of the environmental harm resulting from the intake of cooling water from natural waterways has been the subject of a vast number of general analyses and site-specific studies over decades. It is not the purpose of this report to elaborate on those impacts. The use of closed-cycle cooling at a power generation plant will substantially reduce the amount of cooling water drawn into the plant and any associated impacts. However, there are accompanying environmental impacts associated with a closed-cycle cooling system retrofit that merit consideration.

Brief mention will be made of nine such issues. These are:

- Increased air emissions
- Drift and visible plumes
- Water and waste discharge and/or disposal
- Noise
- Aesthetics
- Construction related effects
- Intake losses
- Solid Waste
- Terrestrial Ecology

7.2.1 Increased Air Emissions

The primary air emissions from fossil plants are, of course, from the combustion of the fuel. As has been noted, the retrofit of once-through cooled plants to wet closed-cycle cooling will reduce the overall plant efficiency and capacity. Therefore, to generate the same energy, more fuel must be burned with a corresponding increase in emissions of NO_X, particulate matter, SO_2 and CO_2.

The methodology for determining the additional power that must be generated and the additional fuel that must be burned is discussed in some detail in Section 4. Two factors must be considered. First, closed-cycle cooling systems consume more operating power for increased circulating water loop pumping power and for the additional requirement for cooling tower fan power. Additional operating power requires that the gross generation be increased in order to hold the net output constant. Second, the increased turbine backpressure increases the plant heat rate and requires more fuel to be burned even to maintain the same gross generation. Once this additional fuel consumption is estimated from a performance comparison between the two cooling systems, the effect on air emissions depends on a several factors.

Many of the coastal plants have low annual capacity factors. However, the plants, although used but infrequently, are needed during periods of peak power demand. This often coincides with hot summer peaks which may also coincide with periods of the worst ambient air quality. In addition, even when operating, they are frequently at less than full load. In these cases, the reduction in net generation would be made up by increasing the fuel flow or firing rate and, hence, the plant output. The increased emissions would then be of the same type and at the same location and would increase in direct proportion to the amount of fuel burned.

There may, however, be some circumstances in which the desired net output could not be maintained from the same unit, either because the unit is already being dispatched at full load or operating concerns will not allow the turbine to run at the elevated backpressure. In such cases, the deficit in net output at the one unit must be made up elsewhere. A number of options exist. The load may be replaced with another, perhaps identical, unit at the same plant. The increased air emissions are again simply proportional to the combined firing rate and would be of the same composition and subject to the same local regulations. Alternatively, the replacement power may come from a similar, gas-fired steam unit at another plant. In this case, the increase in emissions may be similar to the previous case and the emissions will be similar or identical in composition, but differences in the local situations may present more or less severe constraints.

A third possibility is that the power be replaced from units of different types. If these are fossil units, such as simple-cycle gas turbines or gas-fired combined-cycle units, the increase in emissions may be less than if the replacement came from other older steam plants because of lower heat rates and perhaps more modern and efficient environmental controls. If the replacement power were to be obtained from non-fossil units such as nuclear, solar or wind, this would certainly be the case.

Finally, if the power were to be replaced with power generated at coal plants, the emissions would be greater in magnitude and different in character with the addition of sulfur dioxide and particulate matter to the oxides of nitrogen emissions, as well as substantially higher emissions of carbon dioxide A reasonable estimating method, for the case of NO_X might be to assess the increased emissions per MWh at the statewide average of the existing generation mix or approximately 0.3 lb NO_X/MWh. For 2006, the combined output of the California coastal plants was approximately 53,000,000 megawatt-hours. If all units were converted to closed-cycle cooling with an average increase in heat rate of, say, 1%, plus an additional power penalty of 1.25% to account for additional pumps and fans, 1,200,000 MWh would have to be replaced resulting in increased NO_X emissions of about 360,000 pounds per year or about 0.5 tons per day. While small compared to an estimated statewide total from all sources including power generation of about 3,000 tons per day, the local effects may be significant especially in areas with severe air quality issues such as the Los Angeles air basin. Similar increases would also occur for other pollutants, especially particulate matter of less than 10 microns (PM10)which is discussed in a later section on cooling tower drift.

In any case it should be noted that increased emissions from a retrofit would need to be offset incurring associated additional costs. This is discussed in later sections in the context of PM10 emissions.

7.2.2 Drift and Visible Plumes

7.2.2.1 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. It should be recognized, however, that this level is very difficult to achieve. It requires excellent, flaw-free installation of the drift eliminator panels followed by continuous inspection and maintenance to ensure that there is no deterioration in performance. 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 form cooling towers including PM10 and PM2.5 are given by Micheletti [7.1].

- PM10: The source of concern over PM10 is the fact that as the drift droplets evaporate, the dissolved and suspended solids in the circulating water are released as air-borne particles. PM10 emissions are usually estimated (conservatively) as 100% of the TSS and TDS in the estimated drift. As the discussion by Micheletti, demonstrates, the use of the EPA recommended emission factor combined with the assumption that all particles from evaporated drift are classifiable as PM10, likely leads to a vast over-estimate (by a factor of x 10 or more) of PM10 emissions for a modern, well-design and constructed cooling tower. This over-estimate, coupled with the use of seawater for make-up and the resulting very high TDS levels in the circulating water, can lead to predictions of very high PM10 emission rates.

  PM10 concerns are substantial throughout California, in particular in Southern California where non-attainment with ambient air quality standards is severe. As indicated above, the rules for cooling towers vary in California from one Air Quality Control District to another, but, if PM10 offsets should be required, the costs could be substantial even if the offsets were available. However, this may still be a consideration in some areas.

- Infectious Pathogens: The most frequently cited public health issue in the context of cooling towers is the possibility of Legionnaire's Disease, so-called because of an outbreak at an American Legion convention in Philadelphia in 1976 attributed to pathogens (*legionella pneumophilia*) in the cooling tower for the HVAC system in the hotel. While the frequency of occurrence of Legionnaire's Disease is small (approximately 1400 cases reported to the Center for Disease Control annually) and the number of these attributable to cooling towers (at power plants or anywhere else) is even fewer, the question has been investigated extensively in the US and abroad. Treatments of the issue are found in Cooling Technology Institute (CTI) [7.4] and American Society of Heating, Refrigeration and Air-Conditioning Engineers (ASHRAE) [7.5] publications.

While the consequences of exposure can be very severe and even fatal particularly to at-risk (the elderly, smokers, individuals with chronic respiratory problems or with suppressed immune systems) populations, the evidence of harm is sparse and largely anecdotal. Cooling towers are a common element of our industrial, commercial and residential scenes in high-density population areas in all climates. No compelling epidemiology has established a significant threat.

However, expressions of concern during permitting hearings are to be expected, particularly if the use of reclaimed municipal water is proposed even though tertiary treatment is required for any reclaimed municipal water to be used in cooling towers.

- Deleterious impacts of power plant cooling systems on surrounding agriculture have not been an issue except in a few special circumstances. One notable study was conducted in the mid-1970s at the Potomac Electric Power Company's Chalk Point Station in Maryland. In that case, the towers were run on brackish make-up water with a circulating water salinity comparable to sea water (35,000 ppm TDS); the towers were hyperbolic natural draft towers with a plume exit plane elevation of about 400 feet; and the plant was located in a tobacco-growing region with a specialty crop of leaves intended for use as the outer wrappers of cigars. High salinity droplet deposition on the leaves could create small, discolored spots making the leaf unusable without in any way affecting the health of the plant or the quality of the soil. Even under these conditions, the risk was eventually determined to be negligibly small, and the plant and towers continued to operate with no special controls and no adverse impact on the region's agricultural activity.

  A more extensive discussion of this subject is available in a recent report on salt water towers [7.2]

7.2.2.2 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 once 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.

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 supersaturation 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 [7.3].

Fixing the design point requires the determination of the combination of ambient wet and dry bulb temperatures at which a visible plume will form and the number of hours per year during which those conditions pertain. It also needs to be decided under what circumstances a visible plume may be acceptable. If the issue is aesthetics, for example, a plume during hours of coastal fog or at night may well be acceptable. If the issue is highway or airport safety, on the other hand, any occurrence of a plume may be unacceptable.

7.2.3 Water and Waste Discharge and Disposal

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. As a result of recirculating the cooling water in a wet closed-cycle system and associated evaporation solids in the water become more concentrated and periodically must be discharged (i.e. blowndown). Additionally, additives are required to prevent fouling in the closed-cycle and protect physical components of the cooling tower structures. The California Ocean Plan [7.6] has no salinity limits, but local Total Maximum Daily Load (TMDL) requirements may limit discharges, particularly into bays or estuaries. Regulatory constraints such as pertain in California where the State Implementation Policy for implementing the receiving water standards in USEPA's California Toxics Rule allow a discharger who takes water from an impaired water body to discharge back to that water body only if the concentration of the pollutants has not been increased. This offers relief to once-through cooling, but at plants that use cooling towers, blowdown treatment may be required. For plants considering the use of reclaimed municipal water for tower make-up, the normal procedure is to return the blowdown to the municipal treatment plant. In such cases, the increase salinity in the blowdown may present a problem. In some instances, the proposed siting of desalination projects on the California coast has met with difficulty in obtaining permits to discharge the higher salinity effluent without a demonstration that the discharge would not cause adverse environmental impact.

In the event that seawater cooling towers were deemed infeasible for whatever reason, conversion to wet closed-cycle cooling would require the use of alternate water sources such as potable water, reclaimed water or groundwater. Such use would be substantial. Conversion of all the plants in this study would require on the order of 30, billion gallons per year of make-up. Considering the increasing demands on California water supply, this would likely meet significant opposition.

7.2.4 Noise

Cooling tower operation is noisier than once-through cooling operation. The primary noise from cooling facilities is 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 ordinance either at the plant boundary or at some point in a neighboring area. This limit can vary from none to strict depending on the local situation. However, many of the California coastal plants are located in close proximity to residential, commercial and recreational areas. Where strict limits apply, it can be assumed that some degree of noise attenuation would be required.

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. Here again, the issue may simply add to the difficulty of obtaining a permit, add to the cost and duration of the project and warrant consideration in the larger context of balancing the overall benefits to the environment and society of a given decision affecting the choice of cooling systems at power plants.

7.2.5 Aesthetics

In some cases, where plants may be sited in a scenic or urban area, cooling towers and any visible plumes may be deemed as a significant impact on the aesthetics of the locality. In many of the coastal sites of interest to this study, this can be a very important consideration. The scenic beauty of California coast 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 the policy statements of the California Coastal Commission as noted in Section 7.1. This issue is always addressed in siting hearings at the California Energy Commission.

The uncertainty lies in the adage that "beauty is in the eye of the beholder" and it is difficult to know how to establish the importance of this factor. It would be expected to be very site specific. However, recent power plant site certification cases have demonstrated that this is a significant concern in nearly all cases. This leads to delays additional permitting effort and requirements for mitigation efforts to minimize aesthetic impacts. Such measures include less than optimal equipment locations and visual screening with berms, landscaping or other measures with consequently increased costs.

7.2.6 Terrestrial Ecology

The degree to which terrestrial ecological impacts may be a significant issue at a site is very dependent on site-specific conditions. Such impacts would be most significant at facilities were the cooling towers would be constructed in close proximity to or on undisturbed land. Potential impacts could include impacts to wetlands and wildlife including impacts to threatened and/or endangered plants and wildlife. One well documented impact of cooling towers is avian mortality as a result of collisions with cooling towers. The California Energy Commission believes? such issues are most problematic due to poor weather or visibility but the issue may be of concern if towers are placed in locations with threatened or endangered bird species.

7.2.7 Solid Waste

Cooling tower basins become a sink for suspended solids in the cooling tower makeup water. Periodically solids in these basins reach a point where they must be removed and taken to a landfill for disposal. The quality of the sludge removed is highly dependent on the nature of the intake water, chemicals used for cooling tower maintenance as well as materials used for construction.

In addition, any water treatment requirements will involve the disposal of solid waste, such as basin sludge or water treatment system sludge from evaporation ponds, brine concentrators, side-stream softeners or other blowdown reduction processes.

7.2.8 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 amounts of soil. In some situations at California coastal plants, 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. Additionally there can be impacts to local traffic patterns during construction. The associated costs and impacts are impossible to generalize and would need to be developed on a site-specific basis. These impacts are, however, of a relatively short duration during the period of construction.

7.2.9 Intake Losses

As tabulated in Table 2-1, the cooling water flows for the once-through systems range from 375 to 750 gpm per MW and occasionally higher. Cooling water intake for recirculated cooling systems using mechanical draft cooling towers with a typical evaporation rate of 10 gpm/MW ranges from 11 to 13 gpm/MW for fresh water make-up but as high a 20 to 30 gpm/MW for salt water make-up depending on the cycles of concentration at which the tower is operated. While this represents a ten- to seventy-fold reduction in the water taken into the system, EPA in the rule assumed that a reduction in flow would result in a proportional reduction in entrainment mortality. The survival rate of organisms entrained or impinged in once-through systems has been studied and debated extensively but is not normally found to be zero, although it is sometimes assumed to be zero by some California and Federal regulatory agencies. EPRI submitted a technical report [7.7] into the Phase II rulemaking record that entrainment survival at some facilities could be significant. It is, however, extremely unlikely that entrained organisms survive passage through a recirculated cooling system with a cooling tower. Therefore, the implicit assumption that entrainment mortality is reduced in the same proportion as intake flow reduction is questionable.

7.3 Permitting and Social Impacts

7.3.1 Environmental Permits and Approvals

As a result of the potential environmental impacts discussed in the previous section there are a range of federal, state or local permitting requirements that will or may be triggered for any given site. Specific regulatory requirements which must obviously be complied include but are not limited to the Clean Water Act, the California Water Code and the Clean Air Act.

The relevant part of the California Water Code is contained in Section 13142.5 which establishes policies for wastewater discharges to preserve existing beneficial uses and, if possible to restore past ones. The policies cover questions of siting, design, treatment technology and state a preference for recycled water when feasible.

The Clean Water Act regulates cooling tower blowdown to surface water bodies under NPDES rules and establishes water quality-based effluent limits. For ocean discharges these are derived from the California Ocean Plan. If any of the sites are near wetlands, other provisions might apply.

The Clean Air Act contains a number of possibly pertinent programs including New Source Review, New Source Performance Standards, and National Ambient Air Quality Standards. The most important issues to consider are likely to be whether or not a cooling system retrofit would trigger any of the new source conditions. This may depend on whether the retrofit is then followed by an increase in the operating hours of a plant. The most important consideration will be PM_{10} emissions from a cooling tower. Whether or not this would be regulated appears to depend on which Air Quality District the facility is located since cooling towers are not treated uniformly across districts. In some cases, offsets may be required.

In addition to specific limits, general guidance for permit issuance is given by the California Coastal Commission, the Ocean Protection Council, the State Lands Commission and the California Energy Action Plan.

The California Coastal Commission has policies regarding activities in the Coastal Zone which might affect cooling system retrofits. The most important of these are the sustenance of biological productivity of coastal waters, the preservation of access, habitat and the visual and scenic qualities of coastal areas.

Both the Ocean Protection Council and the State Lands Commission have stated policies, reviewed briefly in Section 1, which express a preference for the avoidance and discontinuance of once-through cooling on the coast.

The California Energy Action Plan (EAP), first created in 2003 and supplemented in 2005 (EAPII) provides policy guidance which encourages a balanced approach which maintains affordable energy prices while being sensitive to environmental concerns including global warming and climate change. This plan, however, is a general guide for the development of California's energy future and not a relevant roadmap for decisions regarding any individual plant. More pertinent would be the policy in the 2005 Integrated Energy Policy Report [7.8] which urges the retirement or replacement by 2012 of a number "aging" plants including, specifically, 14 plants addressed in this report.

7.3.2 Other Regulatory Requirements and Issues

In addition to environmental impacts there are other federal, state and local laws and regulations that may be applicable to a large capital project such as construction of a cooling tower. As with environmental issues, they tend to be of a site specific nature and are generally issues when cooling towers are constructed in urban and suburban areas. In such areas impacts as a result of noise, aesthetics, construction traffic, foaming and human health issues are most acute. Additionally to the extent that a cooling tower must be located in close proximity to airports or major highways concerns over public safety may be significant or impede project permitting. Also at such sites Environmental Justice issues may also be a concern.

7.4 References

7.1 Micheletti, W. C., "Atmospheric Emissions from Power Plant Cooling Towers", CTI Journal, Vol. 27, No. 1, Winter, 2006.

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7.3 Lindahl, P. A., Jr. and R. W. Jameson, *Plume Abatement and Water Conservation with the Wet/Dry Cooling Tower*, *in Proceedings: Cooling Tower and Advanced Cooling Systems Conference*. February 1995. EPRI Report No. TR-104867.

7.4 http://www.cti.org/tech_papers/legionnaires.shtml

7.5 http://www.ashrae.org/search/?q=Legionellosis&restrict=

7.6 http://www.swrcb.ca.gov/plnspols/oplans/index.html.

7.7 Review of Entrainment Survival Studies: 1970 to 2000; EPRI Report No. 1000757, December, 2000.

7.8 2005 Integrated Energy Policy Report, California Energy Commission Report No. CEC-100-2005-007-CMF, Adopted November 21, 2005

8
SUMMARY AND CONCLUSIONS

This report documents the results of a study of the technical questions, costs and environmental effects of retrofitting power plants designed for, built with and operating on once-through cooling to closed-cycle cooling. Eighteen California coastal plants currently draw cooling water from the ocean or from adjoining bays, estuaries and inlets. This study uses data provided from seventeen of those plants and publicly available information from one (i.e. Diablo Canyon).

8.1 Background

As a result of concerns over environmental impacts from the entrainment and impingement of fish, shellfish and marine organisms, both the U.S. Environmental Protection Agency and the State of California have begun developing regulations for application to cooling water intake systems.

In 2002, EPA issued the Final Rule on Cooling Water Intake Structures, Phase II, Large Existing Electric Generating Plants. On January 25, 2007 the 2nd Circuit Court remanded to EPA the determination of Best Technology Available (BTA) and specifically requested clarification regarding the determination of closed-cycle cooling as BTA.

In 2005 two California agencies took up consideration of the environmental effects of once-through cooling on coastal waters and of possible mitigating measures. As part of that effort the State Water Resources Control Board has issued a proposed Statewide Policy on Clean Water Act Section 316(b) Regulations which considers, among other things, "the reduction of impingement and entrainment by reducing intake flows to that "commensurate with a closed-cycle recirculating system".

EPRI wishes to provide technical information regarding issues related to the retrofit and use of closed-cycle cooling to inform the regulatory decision making process at both the State and Federal level.

Therefore, EPRI, in collaboration with an owners' group of California coastal plants, initiated this study with then goal of documenting the costs of wet closed-cycle cooling retrofits, assessing the feasibility of dry cooling retrofits at most facilities and discussing the environmental issues associated with wet closed-cycle cooling.

8.2 Summary

This report presents a discussion of all the issues which must be considered in order to establish a conceptual design of a closed-cycle cooling system suitable for retrofitting to an existing once-through cooled plant, develops cost and performance estimates for the retrofitted systems and discusses the consequential environmental, social and economic implications of such retrofits. It must be recognized that the cost ranges presented for each of the sites are derived from general scaling rules developed in previous studies and are not detailed engineering estimates for the sites. Qualitative discussions of site-specific characteristics are given in order to provide guidance of where in the likely range of costs each site would be expected to fall.

This methodology is applied to eighteen of California's coastal plants and the retrofit capital cost results are presented in Table 8-1. The cost for individual plants range from $15 to 1,200 million. Total costs for all the plants on the California coast are estimated to be between $3.6 and $4.2 billion.

Table 8-1
Retrofit Cost Summary

Plant	Capacity	Capacity Factor, %		Degree of Difficullty	Cost Range
	MW	2001 - 2006 Average	2006		MM$
Alamitos	1,656	20.3%	9.7%	Difficult	300 - 350
Contra Costa	680	19.7%	2.3%	Average to Difficult	85 - 130
Diablo Canyon[1]	2,202	89.1%	95.7%	Difficult	750 - 1,200
El Segundo	670	16.4%	10.5%	Difficult	110 - 115
Encina	923	29.8%	14.8%	Difficult	~ 220
Harbor	75	14.9%	5.2%	Average	15 - 17
Haynes	1,675	20.7%	24.7%	Difficult	250
Huntington Beach	880	17.3%	12.9%	Difficult	150
Mandalay	450	17.1%	6.3%	Easy to Average	25 - 40
Morro Bay	600	14.5%	4.1%	Average	~ 80
Moss Landing	2,480	35.3%	29.4%	Average to Difficult	300 - 350
Ormond Beach	1,500	17.0%	3.3%	Average	125 - 135
Pittsburg	650	18.4%	3.7%	Average	~ 90
Potrero	207	23.4%	17.4%	Average	~ 36
Redondo Beach	1,310	16.7%	5.0%	Average to Difficult	~ 200
San Onofre	2,254	83.1%	68.7%	Difficult	> 675
Scattergood	838	22.1%	21.3%	Average to Difficult	100 - 120
South Bay	700	24.0%	15.5%	Average	~ 100
Total	19,750				3,600 - 4,186

[1] Not examined in present study; costs obtained from open literature sources.

8.3 Conclusions

The conclusions of the study may be summarized as follows:

- The technical and engineering issues for retrofitting closed-cycle cooling to existing plants are far more difficult and complex than they are for the installation of closed-cycle cooling as part of new plant construction.
- The problems to be overcome, the resultant project costs and the effects on plant performance are highly site-specific.
- For the seventeen plants addressed in this study, the costs ranged from $15 to $675 million. While plant size is obviously a dominant factor, the cost estimates, normalized on the basis of cooling system water flow rate, range from approximately $150/gpm to over $400/gpm.
- Of the power generating capacity represented by these seventeen plants, over 10 GW is provided by plants over 40 years old and with recent capacity factors of less than 30%.
- The high costs of retrofit are likely to be uneconomic for old plants with low capacity factors and limited remaining life. Should a significant number of these plants find it uneconomical to continue operating, power that, while used infrequently, has nonetheless been important during periods of peak demand may be lost to the California power production network.
- The additional operating power required for closed-cycle cooling equipments plus the reduced unit peak capability amounts to 400 MW for the seventeen plants combined. This penalty translates to a 400 MW reduction in the California power system reserve margin.
- Closed-cycle cooling as a replacement for once-through cooling will significantly reduce the entrainment of fish and shellfish as well as accompanying thermal discharge.
- Closed-cycle cooling has a variety of environmental and social impacts which once-through cooling does not and which may offset in some measure environmental benefits obtained from the reduction in once-through cooling.

A

STONE & WEBSTER (SWEC) COSTS FOR CALIFORNIA COASTAL UNITS

Table A-1
SWEC Results Scaled to $2007 and Modified for Seawater Make-Up

Stone and Webster (2007 $)					
Plant/Unit	**Labor**	**Mat'l**	**Eqpt**	**Indirect**	**Total**
ALAMITOS 1	$4,813,000	$2,807,000	$4,768,000	$7,185,000	$19,572,000
ALAMITOS 2	$4,813,000	$2,807,000	$4,768,000	$7,185,000	$19,572,000
ALAMITOS 3	$9,067,000	$5,284,000	$8,992,000	$13,539,000	$36,883,000
ALAMITOS 4	$9,067,000	$5,284,000	$8,992,000	$13,539,000	$36,883,000
ALAMITOS 5	$13,483,000	$9,007,000	$15,436,000	$21,997,000	$59,923,000
ALAMITOS 6	$13,483,000	$9,007,000	$15,436,000	$21,997,000	$59,923,000
ALAMITOS	**$54,727,000**	**$34,194,000**	**$58,393,000**	**$85,442,000**	**$232,756,000**
CONTRA COSTA 6	$10,705,000	$6,243,000	$10,610,000	$15,984,000	$43,542,000
CONTRA COSTA 7	$10,705,000	$6,243,000	$10,610,000	$15,984,000	$43,542,000
CONTRA COSTA	**$21,410,000**	**$12,486,000**	**$21,220,000**	**$31,968,000**	**$87,084,000**
EL SEGUNDO 3	$9,700,000	$5,656,000	$9,608,000	$14,479,000	$39,443,000
EL SEGUNDO 4	$9,700,000	$5,656,000	$9,608,000	$14,479,000	$39,443,000
EL SEGUNDO	**$19,400,000**	**$11,312,000**	**$19,216,000**	**$28,958,000**	**$78,886,000**
ENCINA 1	$3,337,000	$1,947,000	$3,308,000	$4,983,000	$13,575,000
ENCINA 2	$3,337,000	$1,947,000	$3,308,000	$4,983,000	$13,575,000
ENCINA 3	$3,337,000	$1,947,000	$3,308,000	$4,983,000	$13,575,000
ENCINA 4	$13,062,000	$7,618,000	$12,944,000	$19,502,000	$53,126,000
ENCINA 5	$13,322,000	$7,761,000	$13,202,000	$19,885,000	$54,171,000
ENCINA	**$36,395,000**	**$21,220,000**	**$36,070,000**	**$54,336,000**	**$148,022,000**
HARBOR 8	$3,967,285	$2,312,609	$3,933,257	$5,923,628	**$16,136,779**
HARBOR	**$3,967,285**	**$2,312,609**	**$3,933,257**	**$5,923,628**	**$16,136,779**
HAYNES 1	$6,239,000	$3,637,000	$6,186,000	$9,316,000	$25,378,000
HAYNES 2	$6,239,000	$3,637,000	$6,186,000	$9,316,000	$25,378,000
HAYNES 5	$9,539,000	$5,556,000	$9,451,000	$14,236,000	$38,781,000
HAYNES 6	$9,539,000	$5,556,000	$9,451,000	$14,236,000	$38,781,000
HAYNES 8*	$10,245,000	$6,385,000	$10,860,000	$15,944,000	**$43,434,000**
HAYNES	$41,801,000	$24,770,000	$42,133,000	$63,049,000	**$171,753,000**
HUNTINGTON BEACH 1	$5,855,000	$3,408,000	$5,799,000	$8,736,000	$23,798,000
HUNTINGTON BEACH 2	$5,855,000	$3,408,000	$5,799,000	$8,736,000	$23,798,000
HUNTINGTON BEACH 3	$5,855,000	$3,408,000	$5,799,000	$8,736,000	$23,798,000
HUNTINGTON BEACH 4	$5,855,000	$3,408,000	$5,799,000	$8,736,000	$23,798,000
HUNTINGTON BEACH	**$23,420,000**	**$13,632,000**	**$23,196,000**	**$34,944,000**	**$95,192,000**

Table A-1
SWEC Results Scaled to $2007 and Modified for Seawater Make-Up (Continued)

Stone and Webster (2007 $)					
Plant/Unit	**Labor**	**Mat'l**	**Eqpt**	**Indirect**	**Total**
MANDALAY 1	$5,359,000	$3,122,000	$5,312,000	$8,000,000	$21,792,000
MANDALAY 2	$5,359,000	$3,122,000	$5,312,000	$8,000,000	$21,792,000
MANDALAY	**$10,718,000**	**$6,244,000**	**$10,624,000**	**$16,000,000**	**$43,584,000**
MORRO BAY 3	$10,333,000	$6,028,000	$10,238,000	$15,427,000	$42,027,000
MORRO BAY 4	$10,333,000	$6,028,000	$10,238,000	$15,427,000	$42,027,000
MORRO BAY	**$20,666,000**	**$12,056,000**	**$20,476,000**	**$30,854,000**	**$84,054,000**
MOSS LANDING 1*	$7,821,000	$4,375,000	$6,566,000	$10,882,000	$29,644,000
MOSS LANDING 2*	$7,821,000	$4,375,000	$6,566,000	$10,882,000	$29,644,000
MOSS LANDING 6	$21,782,000	$12,185,000	$18,285,000	$30,307,000	$82,559,000
MOSS LANDING 7	$21,782,000	$12,185,000	$18,285,000	$30,307,000	$82,559,000
MOSS LANDING	**$59,206,000**	**$33,122,000**	**$49,702,000**	**$82,377,000**	**$224,406,000**
ORMOND BEACH 1	$13,719,000	$9,164,000	$15,708,000	$22,383,000	$60,974,000
ORMOND BEACH 2	$13,719,000	$9,164,000	$15,708,000	$22,383,000	$60,974,000
ORMOND BEACH	**$27,438,000**	**$18,328,000**	**$31,416,000**	**$44,766,000**	**$121,948,000**
PITTSBURG 5	$11,275,000	$6,572,000	$11,169,000	$16,830,000	$45,846,000
PITTSBURG 6	$11,275,000	$6,572,000	$11,169,000	$16,830,000	$45,846,000
PITTSBURG	**$22,550,000**	**$13,144,000**	**$22,338,000**	**$33,660,000**	**$91,692,000**
POTRERO 3	$9,452,000	$5,513,000	$9,365,000	$14,111,000	$38,441,000
POTRERO	**$9,452,000**	**$5,513,000**	**$9,365,000**	**$14,111,000**	**$38,441,000**
REDONDO BEACH 5	$5,036,000	$2,935,000	$4,997,000	$7,522,000	$20,491,000
REDONDO BEACH 6	$5,036,000	$2,935,000	$4,997,000	$7,522,000	$20,491,000
REDONDO BEACH 7	$13,483,000	$9,007,000	$15,436,000	$21,997,000	$59,923,000
REDONDO BEACH 8	$13,483,000	$9,007,000	$15,436,000	$21,997,000	$59,923,000
REDONDO BEACH	**$37,038,000**	**$23,884,000**	**$40,866,000**	**$59,038,000**	**$160,828,000**
SAN ONOFRE 1	$43,551,000	$16,496,000	$34,280,000	$54,709,000	$149,036,000
SAN ONOFRE 2	$43,551,000	$16,496,000	$34,280,000	$54,709,000	$149,036,000
SAN ONOFRE	**$87,102,000**	**$32,992,000**	**$68,560,000**	**$109,418,000**	**$298,072,000**
SCATTERGOOD 1	$5,483,000	$3,193,000	$5,427,000	$8,180,000	$22,282,000
SCATTERGOOD 2	$5,483,000	$3,193,000	$5,427,000	$8,180,000	$22,282,000
SCATTERGOOD 3	$13,223,000	$7,704,000	$13,102,000	$19,736,000	$53,765,000
SCATTERGOOD	**$24,189,000**	**$14,090,000**	**$23,956,000**	**$36,096,000**	**$98,329,000**
SOUTH BAY1	$5,036,000	$2,935,000	$4,997,000	$7,522,000	$20,491,000
SOUTH BAY2	$5,036,000	$2,935,000	$4,997,000	$7,522,000	$20,491,000
SOUTH BAY3	$8,187,000	$4,768,000	$8,119,000	$12,223,000	$33,297,000
SOUTH BAY4*	$8,187,000	$4,768,000	$8,119,000	$12,223,000	$33,297,000
SOUTH BAY	**$26,446,000**	**$15,406,000**	**$26,232,000**	**$39,490,000**	**$107,576,000**

B.1 Alamitos Generating Station (AES Southland Corporation)

Location

690 N. Studebaker Road
Long Beach, CA 90815
33° 46’ 01.75” N; 118° 05’ 51.5” W
Contact: Steve Maghy, 562-493-7384

Figure B-1
Alamitos Generating Station––Boundaries and Neighborhood

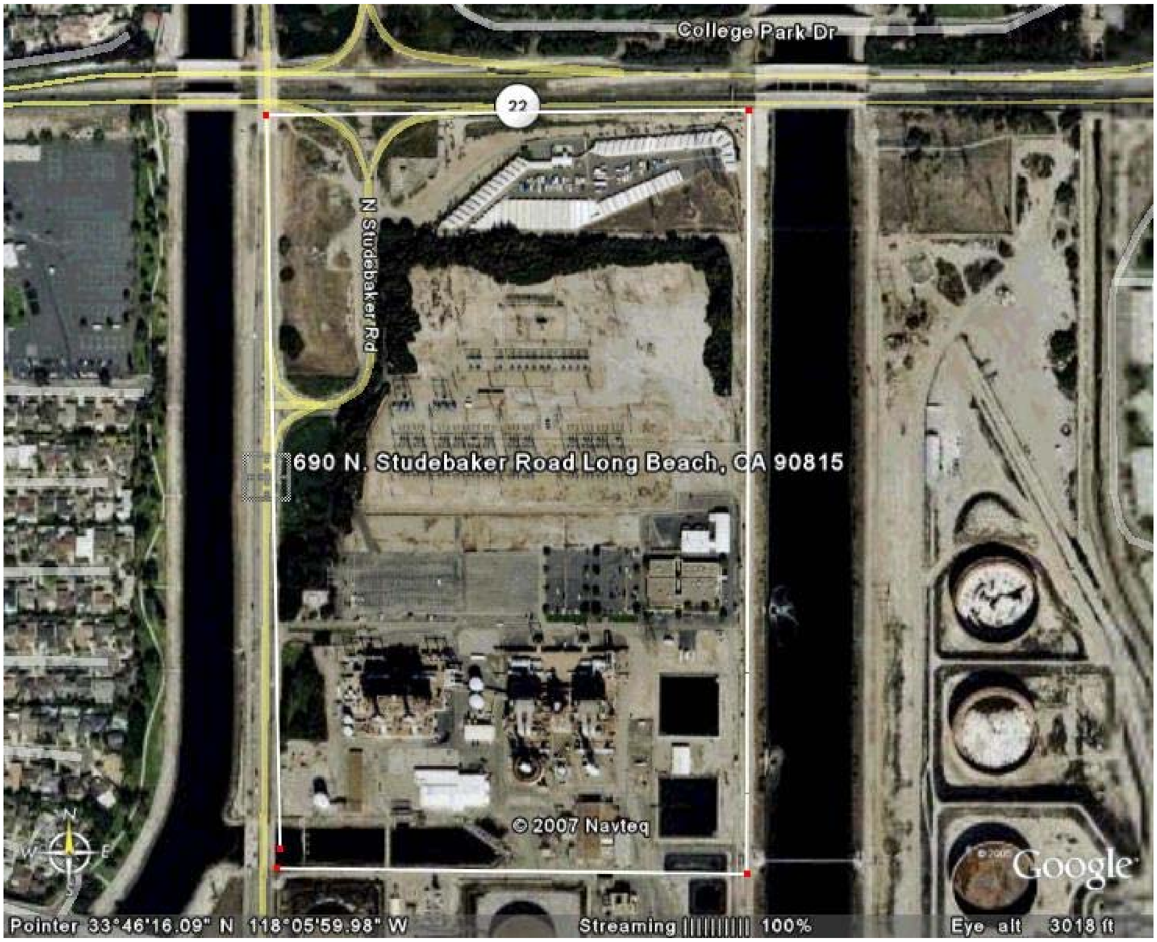


Figure B-2
Alamitos Generating Station: Partial Site View––Units 1 Through 6

Plant/Site Information

Units 1 and 2: 163 MW
Units 3 and 4: 333 MW
Units 5 and 6: 495 MW

Table B-1
Alamitos Cooling System Operating Conditions

Unit	MW	Cooling Water flow		Steam flow	Heat duty	Tin	Tex	Range	Tcond	TTD	Backpressure
		gpm	cfs	lb/hr	Btu/hr	F	F	F	F	F	in Hga
1	163	68,500	152	8.700E+05	8.439E+08	63.0	87.6	24.6	95.6	8.0	1.69
2	163	68,500	152	8.700E+05	8.439E+08	63.0	87.6	24.6	95.6	8.0	1.69
3	333	129,500	288	1.450E+06	1.407E+09	63.0	84.7	21.7	91.7	7.0	1.50
4	333	129,500	288	1.450E+06	1.407E+09	63.0	84.7	21.7	91.7	7.0	1.50
5	495	202,000	449	1.892E+06	1.835E+09	63.0	81.2	18.2	91.7	10.5	1.50
6	495	202,000	449	1.892E+06	1.835E+09	63.0	81.2	18.2	91.7	10.5	1.50

Table B-2
Alamitos Capacity Factors

Unit	2001	2002	2003	2004	2005	2006	Average
1	10.0%	9.5%	8.1%	6.5%	2.7%	3.3%	**6.7%**
2	20.7%	11.1%	8.5%	6.9%	2.1%	2.7%	**8.7%**
3	44.5%	35.0%	36.7%	23.7%	9.1%	17.1%	**27.7%**
4	47.6%	23.6%	20.8%	19.1%	5.5%	7.9%	**20.8%**
5	66.9%	33.7%	20.2%	25.2%	9.3%	9.3%	**27.4%**
6	63.8%	18.8%	18.4%	10.8%	10.1%	11.3%	**22.2%**

Table B-3
Alamitos Meteorological Data

Temperature	Max.	Average	Min.
Inlet water[1]	68	63	58
Atmos. wet bulb[2]	73	58	32
Atmos. dry bulb[2]	102	65	37

[1]Data for nearby ocean temperatures ranges from 57°F to 68°F. It seems likely that given the location of the Alamitos inlet that the water will be significantly warmer in summer months. Estimates were made adding 3°F.

[2] Estimated from tables of “Normals, Means and Extremes—Long Beach, CA”, NOAA, 1992.

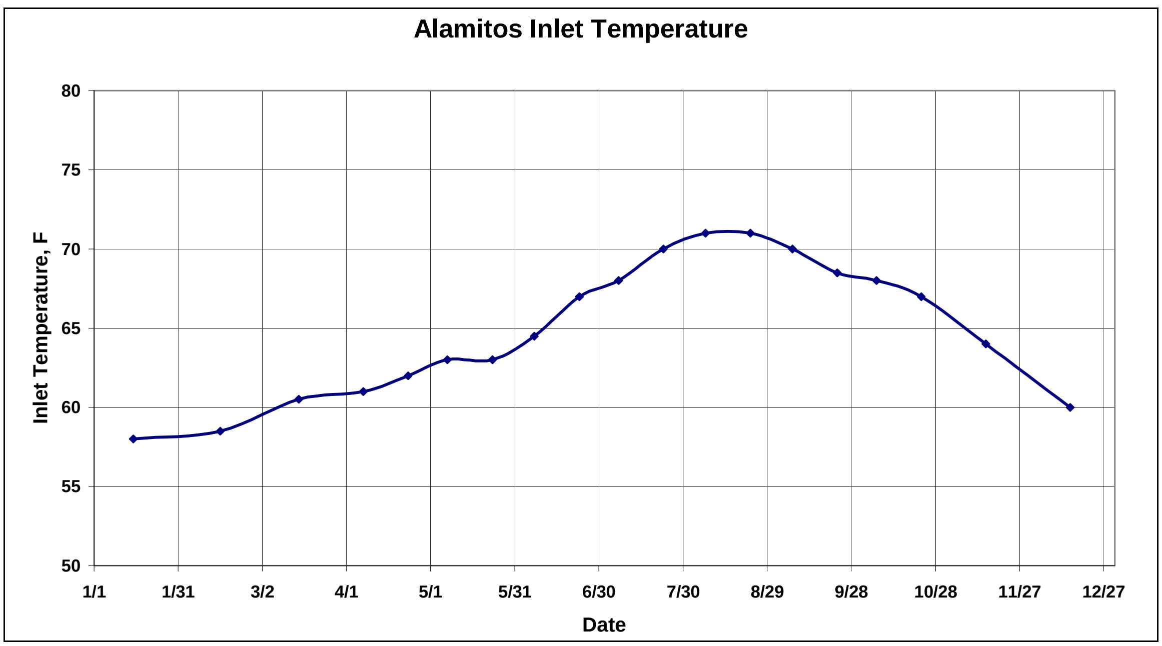


Figure B-3
Alamitos Intake Water Temperature

Plant Operating Data

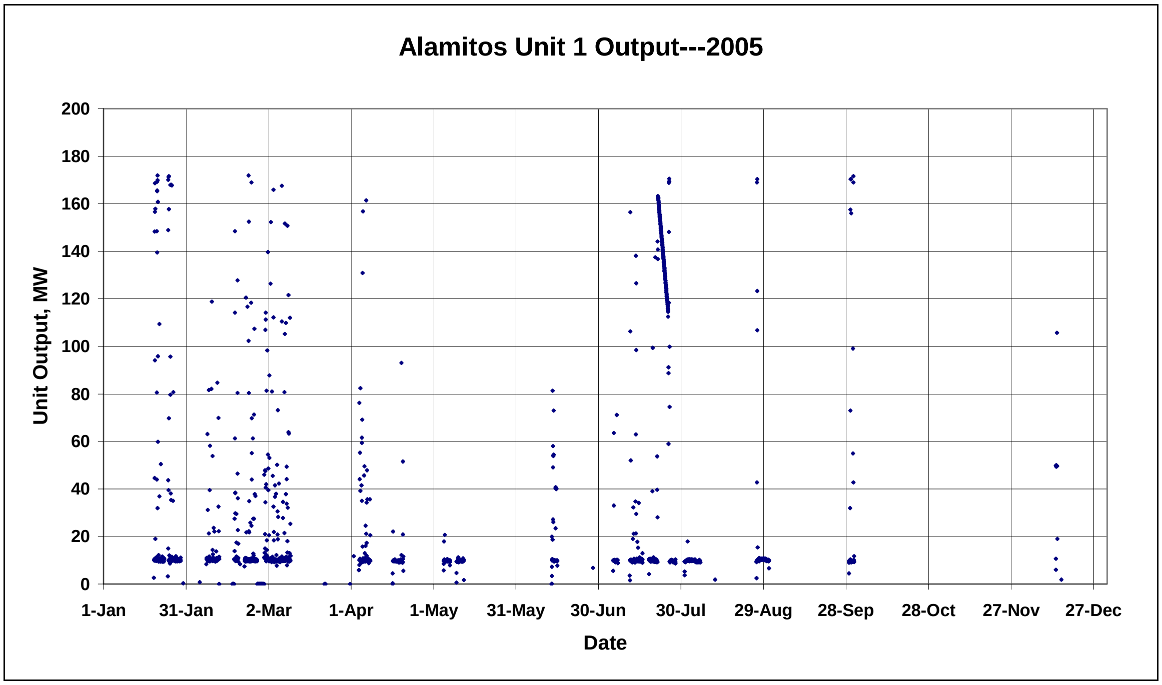


Figure B-4
Alamitos Unit 1 Output––2005

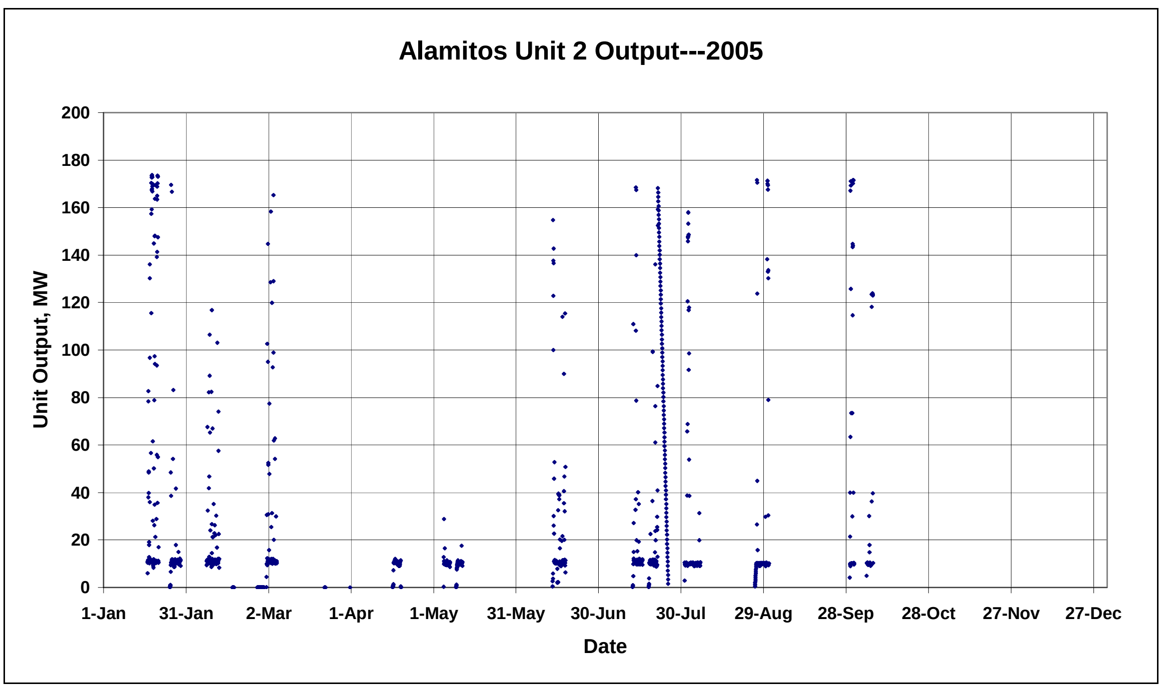


Figure B-5
Alamitos Unit 2 Output––2005

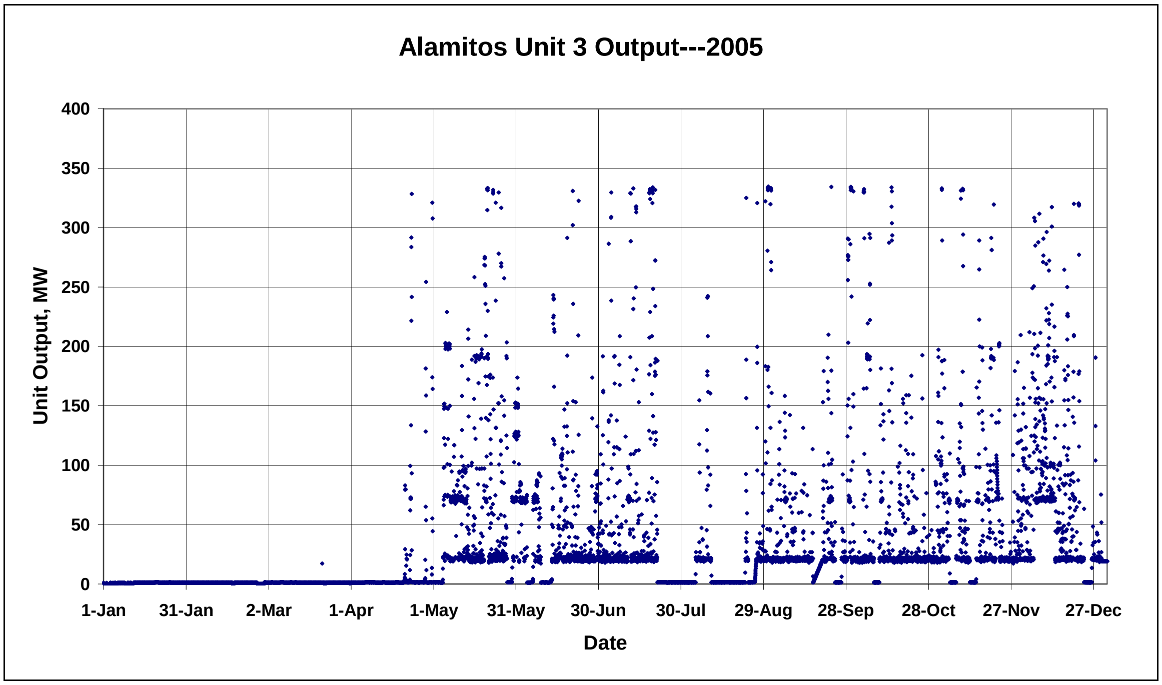


Figure B-6
Alamitos Unit 3 Output––2005

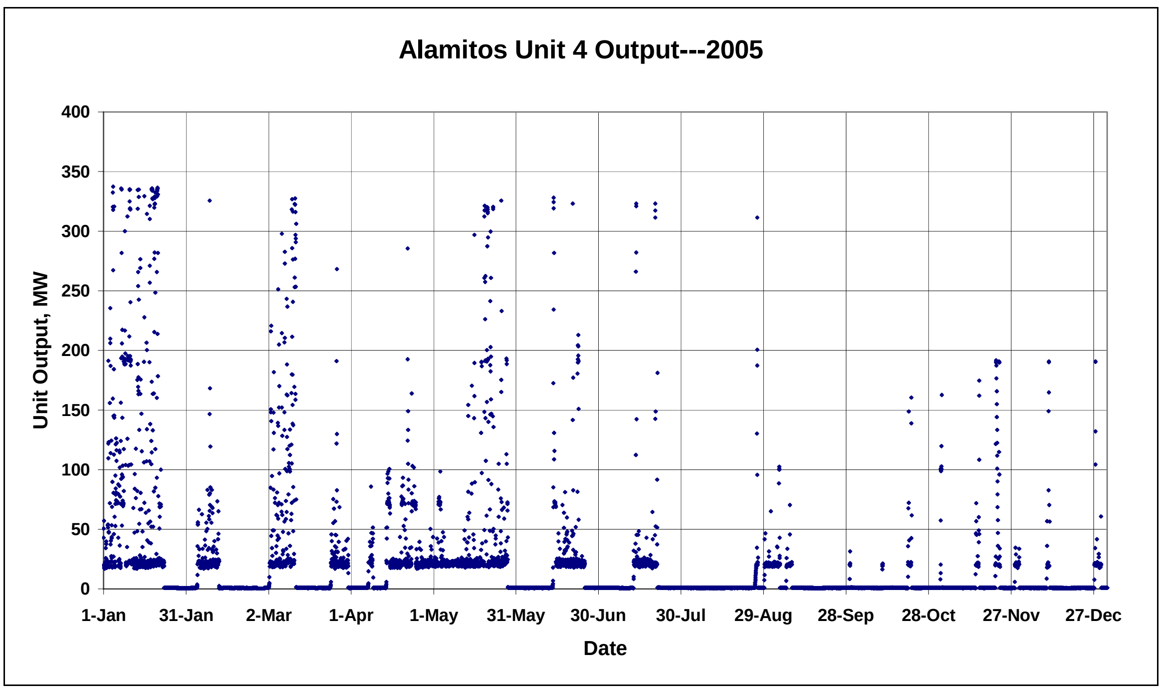


Figure B-7
Alamitos Unit 4 Output

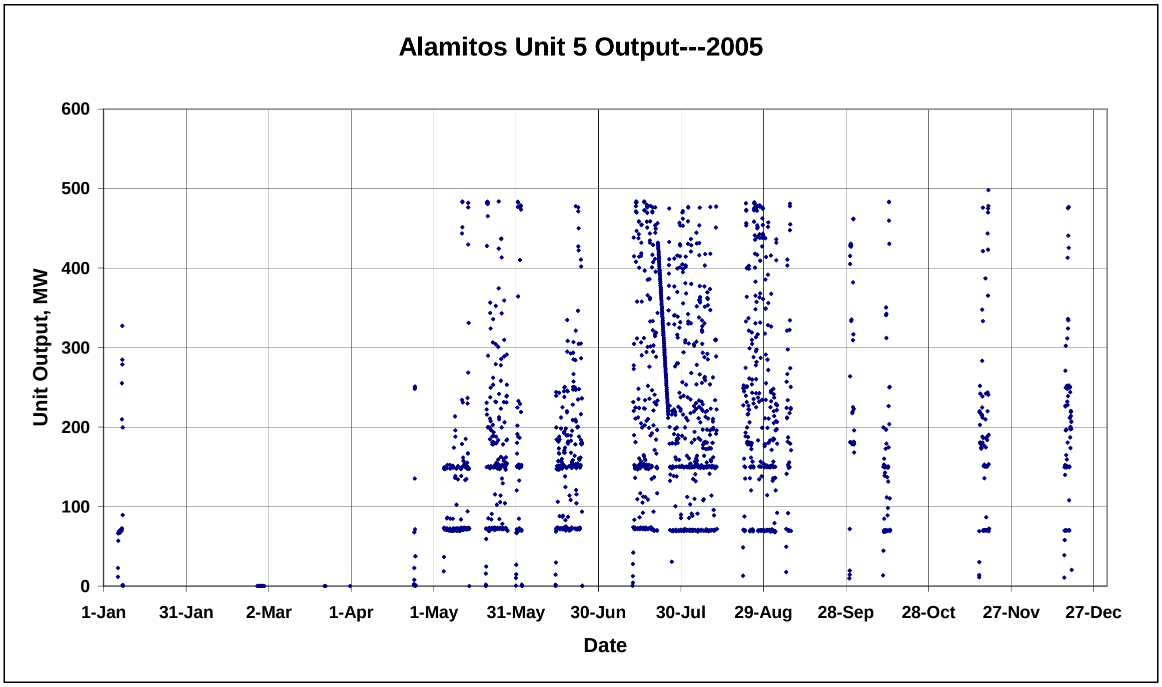


Figure B-8
Alamitos Unit 5 Output

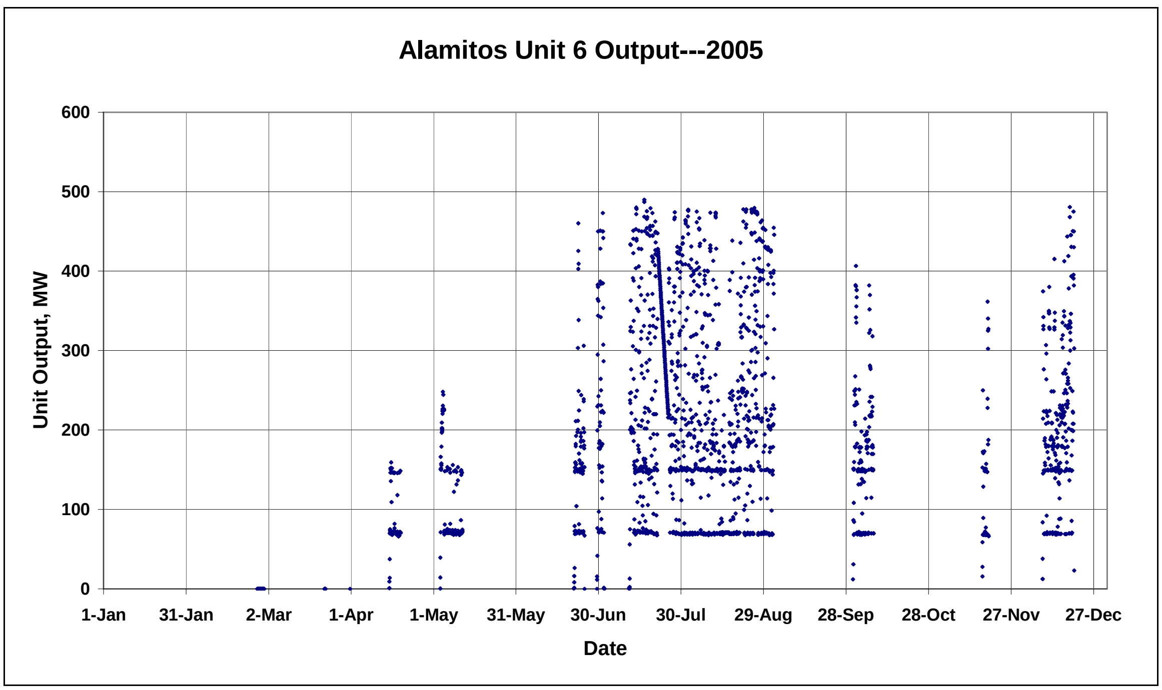


Figure B-9
Alamitos Unit 6 Output

Figure B-10
Alamitos Backpressure Variation––Once-Through Cooling

Cooling Tower Assumptions/Design

Wet cooling system design specs for all units

- Tower type: mechanical draft, counterflow, FRP construction
- Make-up water source: Sea water; 35,000 ppm salinity
- Operating cycles of concentration: n = 1.5

Table B-4
Cooling Tower Water Balance Specifications

Unit	Evaporation	Make-up	Blowdown
	gpm	gpm	gpm
1	1,650	4,950	3,300
2	1,650	4,950	3,300
3	3,350	10,050	6,700
4	3,350	10,050	6,700
5	5,000	15,000	10,000
6	5,000	15,000	10,000

Tower design conditions are for all circulating water flows and condenser specifications unchanged, an assumed tower approach of 10°F and a "1% wet bulb" temperature of 70°F.

Table B-5
Cooling Tower Design Conditions for Full Load on Hot Day

Unit	Ambient Wet Bulb	Range	Approach	TTD	Tcond	Backpressure
	F	F	F	F	F	in Hga
1	70	24.6	10	8	112.6	~ 2.8
2	70	24.6	10	8	112.6	~ 2.8
3	70	21.7	10	7	108.7	~ 2.5
4	70	21.7	10	7	108.7	~ 2.5
5	70	18.2	10	10.5	108.7	~ 2.5
6	70	18.2	10	10.5	108.7	~ 2.5

Therefore, on the hottest day at full load, all units would operate at a backpressure of approximately 2.5 to 2.8 in Hga. Over the course of the year when the ambient wet bulb temperature would be lower, the backpressure would vary as indicated in the following figure. A comparison is given to the backpressure estimated with once-through cooling and indicates that the backpressure would normally be elevated by 0.5 to 1. in Hga.

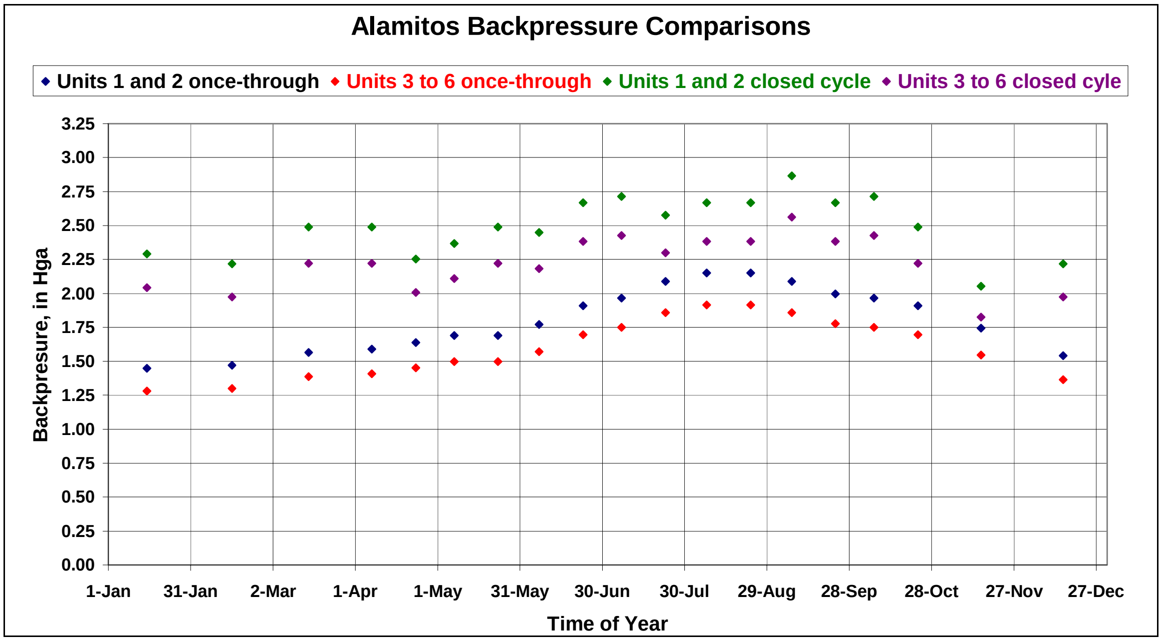


Figure B-11
Backpressure Comparisons

Wet Retrofit Costs

Table B-6
S&W Cost Estimates

S&W Costs---escalated to 2007; x 1.07 for seawater					
Unit	**Labor**	**Material**	**Equipment**	**Indirect**	**Total**
1	$4,813,000	$2,807,000	$4,768,000	$7,185,000	$19,572,000
2	$4,813,000	$2,807,000	$4,768,000	$7,185,000	$19,572,000
3	$9,067,000	$5,284,000	$8,992,000	$13,539,000	$36,883,000
4	$9,067,000	$5,284,000	$8,992,000	$13,539,000	$36,883,000
5	$13,483,000	$9,007,000	$15,436,000	$21,997,000	$59,923,000
6	$13,483,000	$9,007,000	$15,436,000	$21,997,000	$59,923,000
Plant Total	$54,727,000	$34,194,000	$58,393,000	$85,442,000	$232,756,000

Table B-7
Maulbetsch Consulting Survey Estimates

JSM Survey; escalated to 2007 $; x 1.07 for salinity			
Unit	**Easy**	**Average**	**Difficult**
1	$11,302,500	$18,837,500	$29,112,500
2	$11,302,500	$18,837,500	$29,112,500
3	$21,367,500	$35,612,500	$55,037,500
4	$21,367,500	$35,612,500	$55,037,500
5	$33,330,000	$55,550,000	$85,850,000
6	$33,330,000	$55,550,000	$85,850,000
Plant Total	$132,000,000	$220,000,000	$340,000,000

Dry Cooling

Similar cost estimates can be made for a dry cooling retrofit. The basic assumption is that for plants with low capacity factors, they must be available to produce close to full load on the hottest days of the year when the system load is at its peak.

- Direct dry cooling: forced, mechanical-draft air-cooled condenser
- Steam flow: 870,000 lb/hr (Units 1 and 2)
  1,450,000 lb/hr (Units 3 and 4)
  1,892,000 lb/hr (Units 5 and 6)
- Design dry bulb: 100°F (mid-way between 0.4% dry bulb and median of extreme highs)
- Design turbine exhaust pressure: 4.5 in Hga (based on assumption that turbines of this age and design trip at 5 in Hga and that the plant would not wish to reduce output on the hottest days)
- Corresponding condensing temperature: 130°F

Therefore, ACC design ITD ($T_{condensing}$ - $T_{design\ ambient}$) = 130°F – 100°F = **30°F**

Dry Cooling Retrofit Costs

AC costs can be roughly estimated from EPRI Report No. 1005358; "Comparison of Alternate Cooling Technologies for U.S. Power Plants", August, 2004.

Vendor information for a design of:

Steam flow: 870,000 lb/hr (Units 1 and 2)

1,450,000 lb/hr (Units 3 and 4)
1,892,000 lb/hr (Units 5 and 6)

ITD: 30°F

Price: 2007 $

Table B-8
Dry Cooling Retrofit Cost Estimates––Units 1 and 2

Source/Basis	Equipment	Erection	Electrical	Duct Work	Indirect	Total	Cells
Vendor 1	$17,662,000	$7,559,000	$1,157,000	$116,000	$15,299,000	$41,792,000	50
Vendor 2	$18,511,000	$7,944,000	$926,000	$116,000	$15,881,000	$43,377,000	40
Vendor 3	$15,117,000	$7,404,000	$926,000	$116,000	$13,599,000	$37,162,000	40
Average	$17,097,000	$7,636,000	$1,003,000	$116,000	$14,927,000	$40,777,000	45
Scaled to 2007 $	$22,879,000	$9,094,000	$1,342,000	$155,000	$19,323,000	$52,792,000	

Table B-9
Dry Cooling Retrofit Cost Estimates––Units 3 and 4

Source/Basis	Equipment	Erection	Electrical	Duct Work	Indirect	Total	Cells
Vendor 1	$29,437,000	$12,598,000	$1,928,000	$193,000	$25,498,000	$69,653,000	83
Vendor 2	$30,852,000	$13,240,000	$1,543,000	$193,000	$26,468,000	$72,295,000	67
Vendor 3	$25,195,000	$12,340,000	$1,543,000	$193,000	$22,665,000	$61,937,000	67
Average	$28,495,000	$12,727,000	$1,672,000	$193,000	$24,878,000	$67,962,000	75
Scaled to 2007 $	$38,132,000	$15,157,000	$2,237,000	$258,000	$32,205,000	$87,987,000	

Table B-10
Dry Cooling Retrofit Cost Estimates––Units 5 and 6

Source/Basis	Equipment	Erection	Electrical	Duct Work	Indirect	Total	Cells
Vendor 1	$38,410,000	$16,438,000	$2,516,000	$252,000	$33,270,000	$90,885,000	109
Vendor 2	$40,257,000	$17,276,000	$2,013,000	$252,000	$34,536,000	$94,333,000	87
Vendor 3	$32,875,000	$16,102,000	$2,013,000	$252,000	$29,574,000	$80,817,000	87
Average	$37,181,000	$16,607,000	$2,182,000	$252,000	$32,462,000	$88,679,000	98
Scaled to 2007 $	$49,756,000	$19,777,000	$2,919,000	$337,000	$42,022,000	$114,808,000	

The major difficulty for dry cooling, in addition to very high cost, is the lack of adequate space for the ACC and the distance of candidate locations from the turbine halls. ACC's are normally sited quite close to the turbine exhaust to minimize the length (and therefore the cost and the steam side pressure drop) of the steam duct. No obvious way to address this problem could be seen. Therefore, dry cooling retrofit was not considered further at Alamitos.

Effect on Plant Performance

A retrofitted cooling system of either the wet or dry type would have a deleterious effect on the plant net heat rate. This arises from two effects:

1. Considering only the wet system, the power requirements will be higher than the current pumping power requirements for the once-through system. This power is used for the additional circulating pumps and for the cooling tower fans and represents power that must be generated but cannot be sold.

2. The plant will operate at a higher backpressure and therefore a higher heat rate with closed cycle cooling. This effect will be much more pronounced for a dry system than for a wet system.

The additional power requirements are estimated as follows:

Pumping power: As noted in Section 4.1.3, the existing circulating water system will discharge into a sump from which a second set of pumps will draw the water and discharge it to the top of the cooling tower. The circulating water flow rate must be pumped through an additional head rise. This will be estimated at 40 feet to account for the lift out of the sump, the rise to the hot water distribution deck on the top of the tower and the head loss through the circulating water lines. A combined pump/motor efficiency of 75% is assumed. Each of these factors would be refined in a detailed analysis, but these are considered adequate to give a reasonable estimate
of the effect of additional operating power on the plant. For the several units at Alamitos:

Table B-11
Alamitos Units: Retrofit Additional Pumping Power

Unit	Flow	Head	Eff	Power	Motor
	gpm	ft		kW	MW
1	68,500	40	0.75	516.0	0.69
2	68,500	40	0.75	516.0	0.69
3	129,500	40	0.75	975.4	1.30
4	129,500	40	0.75	975.4	1.30
5	202,000	40	0.75	1521.5	2.03
6	202,000	40	0.75	1521.5	2.03

Fan power: Similarly cooling tower fan power can be roughly estimated. It is assumed for retrofits on older, lower capacity factor units, the tower would be sized to "low first cost" design since the number of operating hours is low and power penalties are less severe. This is consistent with the assumptions made in the retrofit capital cost estimates. The number of cells will be estimated as one cell per 10,000 gpm of circulating water flow, the fan horsepower at 200 HP and a motor efficiency of 90%. For the Alamitos units this results in:

Table B-12
Alamitos Units: Retrofit Fan Power

Unit	Flow	Cells	Eff	Power	Motor
	gpm	n		hp	kW
1	68,500	7	0.9	1,400	1,160
2	68,500	7	0.9	1,400	1,160
3	129,500	13	0.9	2,600	2,155
4	129,500	13	0.9	2,600	2,155
5	202,000	20	0.9	4,000	3,316
6	202,000	20	0.9	4,000	3,316

This represents a combined, full-load operating power requirement of approximately 21.2 MW or approximately 1.07% of the plant power rating of 1,982 MW. The actual annual cost will obviously depend on the capacity factor, the number of hours on-line, and whether some fans are turned off when operating at part load. Also, since the cooling system was sized for full load at acceptable backpressures at the so-called "1%" ambient conditions, it would be well oversized for nearly the entire year. Therefore, the effect of requiring additional operating power for the pumps and fans coupled with operation at higher heat rate would be an increase in the fuel burned rather than a reduction in plant output.

Heat rate penalty: As seen in the earlier plot of comparative backpressures, the condensing pressure with closed-cycle wet cooling will run typically 0.5 to 1.0 in Hga higher than it would with once-through ocean cooling and increases to about 2.75 in Hga on the hottest days. The effect is less at part load. No information is available to estimate the effect on heat rate resulting from the increased backpressure. However, information from comparable units suggest an increase of at least 0.25% for each 0.1 in Hga increase in backpressure above design might be reasonable. The comparative plot shown earlier suggests that closed cycle cooling will result in increased backpressure throughout the year ranging from 0.5 to 1. in Hga with a corresponding heat rate penalty of 0.5 to 1.%. In the absence of other information, it is assumed to be applicable to the Alamitos units as well resulting in a heat rate penalty at full load of 0.5 to 1.0% for the units at the plant. It should be noted that some estimates on other individual units of similar size and age have been much higher, up to a heat rate increase of as much as 1,000 Btu/kWh for a backpressure increase of 1.5 to 2.5 in Hga..

Capacity limits

The increased back pressure will likely result in an output restriction on the hottest day. The magnitude of the shortfall will depend on the operating philosophy. If the firing rate is held constant, a 1% heat rate penalty would correspond to roughly a 1% reduction in output. If the design of the units permits, this could presumably be compensated for with overfiring, but the heat rate penalty and hence the fuel cost would increase even further.

This would appear to be a minor effect on output. If, however, it were to be decided that operation at a backpressure of 2.5 in Hga constituted an unacceptable maintenance risk to the turbine, then the firing rate would need to be reduced to hold whatever backpressure was consider acceptable. Information to estimate what the shortfall would be in that case is not available but presumably could be estimated by plant staff based on the information given above.

Maintenance Costs

Commonly used factors for maintenance (labor, materials, chemicals, etc.) for wet cooling systems range from 2 to 3 % of the system capital costs.

For wet systems, the important costs are for water treatment, biofouling control and keeping the basin clean. Using salt water and having salt drift around the plant would require rust control, extra painting, etc. Using the high end of typical factors, assume 3. to 3.5% of the capital cost of the tower. It is unclear how AES would allocate these costs between operation and maintenance, but an estimate of 3% of the “average” capital costs for all units of $200 million could amount to approximately $6,000,000 per year.

Additional Cost Considerations

Although the S&W costs are reasonably close to the Maulbetsch Consulting survey's "Average" difficulty estimate, neither of those estimates can account for any site-specific difficulties which might be encountered at the Alamitos site. Those items that could cause a retrofit at this site to be in a different, either "High" or "Easy" category include:

- Difficulty in locating the tower
- Unusual site preparation costs
- Significant interferences to the cost of installation of the circulating water lines
- The need for cooling tower plume abatement
- Stringent noise control
- The use of an alternate make-up water

Location of Tower/Unusual Site Preparation Costs/Interferences

It appears that space would be available either to the north of the plant or to the south if what appear to be unused fuel tanks were removed. (See site photo at beginning of write-up). No information is available regarding the suitability of these sites, but a number of items would need to be considered:

i. The need to demolish, relocate and rebuild existing structures, including the fuel tanks, for some locations.

ii. Unstable soil conditions requiring significant foundation work such as deep pilings to stabilize the towers. This is likely given the location of the plant.

iii. Drift deposition from salt water towers.

iv. Underground infrastructure which would make the installation of underground circulating water lines difficult and costly.

v. Remoteness of current intake bays from towers north of the plant and difficulty in tying into the existing circulating water system.

vi. Probable neighborhood objections to visible plumes, corrosive drift and noise.

vii. The need for PM10 offsets for expected drift from seawater towers.

Plume Abatement

Based on the view in the aerial photo of the neighboring area, it appears that a visible plume could be a serious issue at this site primarily from an aesthetic viewpoint. It is reasonable to assume that a plume abatement tower would be required. Plume abatement towers have an air-cooled section on top of the wet tower. The hot water is pumped to the top of the tower, passes down through the dry section and then discharged onto the hot water distribution deck of the wet section. The air passing across the finned tubes of the dry section mixes with the wet plume coming off the wet section and keeps it from becoming saturated and condensing in the cold atmosphere. The need for a plume abatement tower would increase both the capital cost of the tower itself by a actor of perhaps 2. to 2.5 and the additional pumping power by an additional 30 to 50% due to the greater height to which the hot water must be pumped.

Aesthetics

In addition to any issues with a visual plume, the simple appearance of a cooling tower is sometimes considered an aesthetic affront. In this instance, even though the towers would be visible to neighbors, considering the number, size and bulk of the plant buildings already present, it does not appear that this would present a major problem.

Noise Control

Noise from wet cooling towers comes both from the fans and from the water cascading through the fill. Fan noise can be diminished by fan design or the reduction in air velocity which sometime requires the use of bigger, or more, cells. The water noise is more difficult to reduce and usually requires the construction of sound barriers around the cooling tower. As in the case of the plume abatement question, the aerial photo of the plant and the neighboring area makes it appear that cooling tower noise should not be a serious constraint. In case that it is, the capital cost of the tower itself cost might increase from 20 to 40%.

Alternate Sources of Make-Up Water

The use of seawater make-up can introduce intractable problems regarding drift and related maintenance considerations. (See later discussion of drift and PM10.) An alternative can be to purchase reclaimed water from nearby municipal water treatment facilities.

In this instance, however, possibility of using reclaimed water for wet cooling tower makeup was considered and rejected due to the distance of sources from the plant, the expected very high cost of installing delivery and return pipelines to the remote sources and the expected extended time required to obtain permits even if the approach were deemed feasible.

Shutdown Period

There is often concern over the period of post plant availability during the retrofit construction period. In this instance, it appears that the major part of the construction could be done while the plant is on-line, with shutdown required only for the final tie-in of the circulating water lines to the existing water circuit. There is no information available to estimate how long this might be. However, the operating profiles shown earlier for 2005 indicate periods of little or no operation. Therefore, it appears that the tie-in could be accomplished with no serious downtime.

Other Environmental Issues

Retrofit to a closed-cycle cooling system introduces some environmental issues which a once-through cooling system does not. These are increased air emissions from the stack and drift from the cooling tower.

Stack Emissions

In an earlier section it was noted that a closed-cycle retrofit increase the unit net output because of heat rate penalties and the use of increased operating power. In this instance these together were estimated at from 1 to 2%. Therefore, the delivery of the same amount of electric power to the grid will require the burning of additional fuel at some location to make up that lost at Alamitos. Based on the unit heat rate information provided, this does not appear to be major effect in this case. Furthermore, in the discussion of this issue in Chapter 7, it was pointed out that the effect of making up this shortfall was highly variable depending on how and where the replacement per was generated. Therefore, no attempt is made to asses the effect in quantitative terms beyond pointing out that reliable estimates of the shortfall to be expected from full load operation can be made.

Drift

It is assumed that any cooling tower would be equipped with state-of-the-art drift eliminators rated at about 0.0005% of circulating water flow. The following table estimates the amount of drift to be expected from such designs. In addition, as discussed earlier, Federal EPA and State regulations characterize all solids carried off in cooling tower drift as PM10. The cost of offsetting these amounts, should it be necessary will vary considerably from site to site as will the severity of the regulatory constraints.

Table B-13

Alamitos Drift Estimates

Unit	Flow	Drift[1]	Drift	PM10	PM10	Cap. Factor	PM10
	gpm	gpm	lb/hr	lb/hr	tons/year[2]	%	tons/year[3]
1	68,500	0.34	171	8.56	37.5	3.3	1.2
2	68,500	0.34	171	8.56	37.5	2.7	1.0
3	129,500	0.65	324	16.18	70.9	17.1	12.1
4	129,500	0.65	324	16.18	70.9	7.9	5.6
5	202,000	1.01	505	25.24	110.6	9.3	10.3
6	202,000	1.01	505	25.24	110.6	11.3	12.5

1. At drift eliminator efficiency of 0.0005%
2. Assumes full load all year
3. At 2006 capacity factor

General Conclusion

On balance, it is concluded that the nature of the likely problems and additional costs encountered at Alamitos would put the retrofit at this site in a “difficult” category. Based on the results from the Maulbetsch Consulting survey presented above, this would put the project cost in the range of $300 to 350 million. The costs for Units 1 and 2 alone are likely to be nearly $30 million each which is particularly problematic given that the capacity factors for these units have been in the range of 2 to 3% for the last three years and have averaged under 10% for the last six years.

B.2 Contra Costa Generating Station - Mirant

Location

Wilbur Avenue
Antioch, CA 94509
Lat/long: 38° 00’ 44.35” N; 121° 45’ 40.64” W
Contact: Steve Bauman, 925-427-3381

Figure B-12
Contra Costa Boundaries and Neighborhood

Figure B-13
Contra Costa Site View

Plant/Site information

Unit 6: 340 MW
Unit 7: 340 MW

Very little information is available about the operating profile at Contra Costa or the design specifications for the condensers. Operating data in the following table were estimated based on the following assumptions:

Condenser heat load:	5,000 Btu/kWh
Circulating water flow:	220 mgd
Condenser TTD:	7°F

Table B-14
Contra Costa Cooling System Operating Conditions

Unit	MW	Cooling Water flow		Steam flow	Heat duty	Tin	Tex	Range	Tcond	TTD	Backpressure
		gpm	cfs	lb/hr	Btu/hr	F	F	F	F	F	in Hga
6	340	153,000	340	1.800E+06	1.700E+09	62.3	84.6	22.3	91.6	7.0	1.50
7	340	153,000	340	1.800E+06	1.700E+09	62.3	84.6	22.3	91.6	7.0	1.50

Table B-15
Contra Costa Capacity Factors

Unit	2001	2002	2003	2004	2005	2006	Average
6	62.0%	28.5%	1.9%	4.1%	1.1%	0.8%	**16.4%**
7	49.7%	37.1%	16.3%	21.6%	10.0%	3.8%	**23.1%**

Table B-16
Contra Costa Meteorological Data

Temperature	Max.	Average	Min.
Contra Costa Source water	82	62.3	45
Atmos. wet bulb	65.8	52.5	40
Atmos. dry bulb	90	59.3	40

Plant source water temperature and unit discharge water temperatures for 2006 were provided. The source water temperature is plotted in the following figure. The sudden discontinuity to a lower temperature at the end of March is unexplained. Given that it results in a negative temperature rise across the condensers it is assumed to be in error.

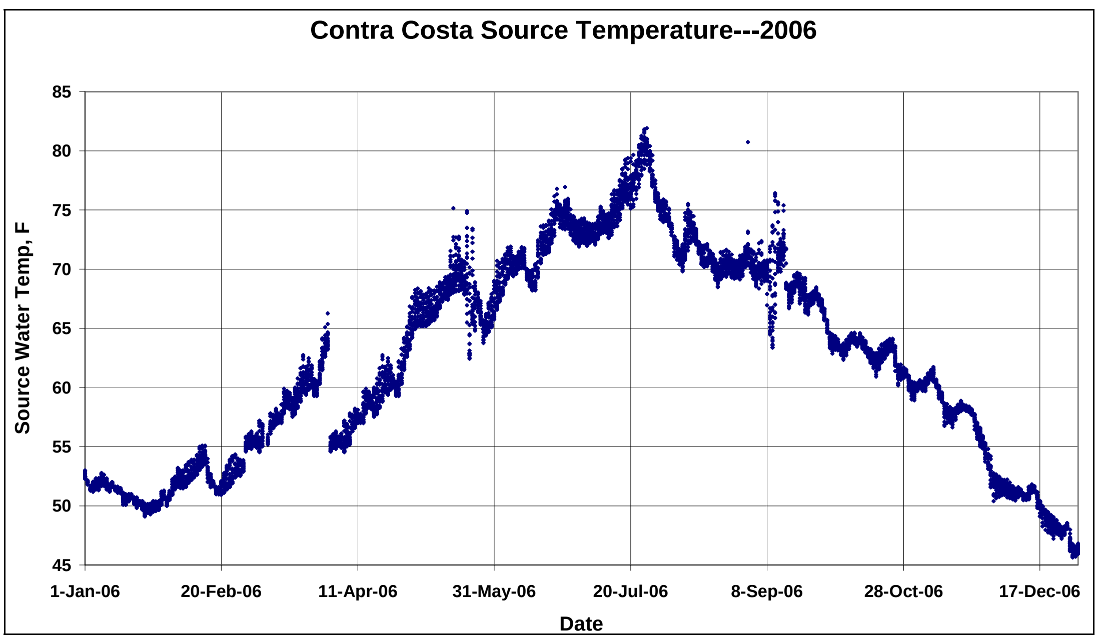


Figure B-14
Contra Costa Inlet Temperature

Plant Operating Data

No power output data are available. As a surrogate, the condenser temperature rise data for Units 6 and 7 are shown in the following figures.

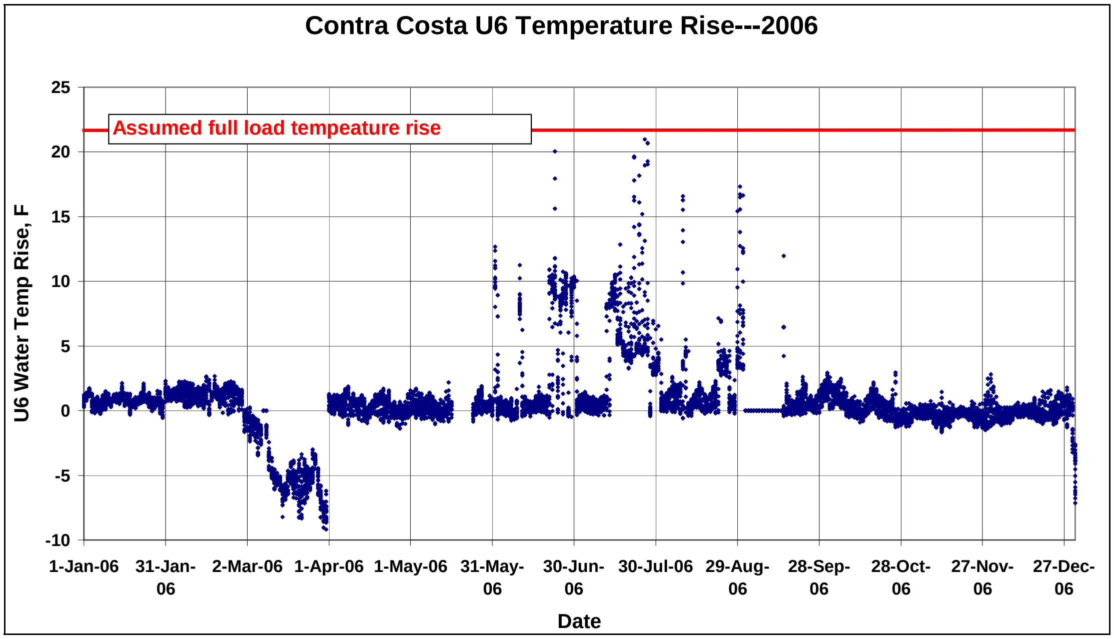


Figure B-15
Unit 6 Condenser Temperature Rise Variation––2006

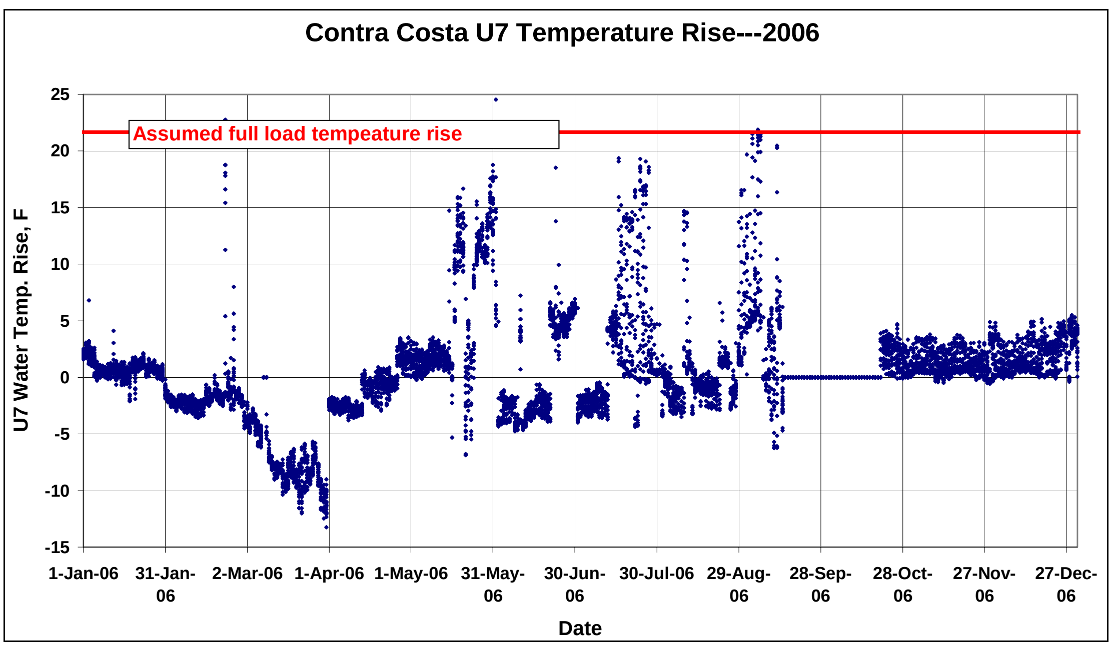


Figure B-16
Unit 7 Condenser Temperature Rise Variation––2006

Unit 6 results appear reasonable for no or part load operation after April 1. The continuing negative temperature rise information for Unit 7 is unexplained. In any case, the units appear to have operated very little during 2006, consistent with the capacity factor information in the table above.

In the absence of output data, no estimates of actual backpressure can be made.

Cooling Tower Assumptions/Design

Wet cooling spec (example)

Normal assumptions for wet cooling tower design would give the following:

- Tower type: mechanical draft, counterflow, FRP construction
- Make-up water source: Tidal, variable salinity;
- assume maximum salinity of 35,000 ppm
- Operating cycles of concentration: n = 1.5
- Evaporation rate: Units 6 and 7--- ~ 3,500 gpm each
- Make-up rate (@ n = 1.5): Units 6 and 7--- ~ 10,500 gpm each
- Blowdown (@ n = 1.5): Units 6 and 7--- ~ 7,000 gpm each

At full load and on the 1% wet bulb day, an assumed cooling tower approach of 10°F with all other cooling system values remaining the same:

- Ambient wet bulb: 66°F
- Approach: 10°F
- Range: 22.3°F
- TTD: 7°F

The condensing temperature is given by

$$T_{cond} = 66 + 10 + 22.3 + 7 = 105.3°F$$

with a corresponding backpressure of ~ 2.25 in Hga.

This results in backpressure elevation at full load on the hottest day of approximately 0.75 in Hga. The backpressure elevation throughout the year would vary between 0.5 to 0.75 in Hga.

Wet Retrofit Costs

Table B-17
S&W Cost Estimates

S&W Costs---escalated to 2007; x 1.07 for seawater					
Unit	**Labor**	**Material**	**Equipment**	**Indirect**	**Total**
6	$10,705,000	$6,243,000	$10,610,000	$15,984,000	$43,542,000
7	$10,705,000	$6,243,000	$10,610,000	$15,984,000	$43,542,000
Plant Total	$21,410,000	$12,486,000	$21,220,000	$31,968,000	$87,084,000

Table B-18
Maulbetsch Consulting Survey Estimates

JSM Survey; escalated to 2007 $; x 1.07 for salinity			
Unit	**Easy**	**Average**	**Difficult**
6	$25,178,000	$41,964,000	$64,853,000
7	$25,178,000	$41,964,000	$64,853,000
Plant Total	$50,356,000	$83,928,000	$129,706,000

Dry Cooling

Similar cost estimates can be made for a dry cooling retrofit. The basic assumption is that for plants with low capacity factors, they must be available to produce close to full load on the hottest days of the year when the system load is at its peak. Therefore, for each unit:

- Direct dry cooling: forced, mechanical-draft air-cooled condenser
- Steam flow: ~ 1,800,000 lb/hr (Unit 6 and 7 full load)
- Design dry bulb: 90ºF (mid-way between 0.4% dry bulb and median of extreme highs)
- Design turbine exhaust pressure: 4.5 in Hga (based on assumption that turbines of this age and design trip at 5 in Hga and that the plant would not wish to reduce output on the hottest days)
- Corresponding condensing temperature: 130°F

Therefore, ACC design ITD ($T_{condensing}$ - $T_{design\ ambient}$) = 130°F – 90°F = **40°F**

Dry Cooling Retrofit Costs

AC costs can be roughly estimated from EPRI Report No. 1005358; "Comparison of Alternate Cooling Technologies for U.S. Power Plants", August, 2004.

Vendor information for a design of:

Steam flow:1,800,000 lb/hr (scaled from example case of 1,080,000 lb/hr)

ITD: 40ºF
Price: 2007 $

Table Error! No text of specified style in document.**-1**
Dry Cooling Retrofit Cost Estimates

Source/Basis	Equipment	Erection	Electrical	Duct Work	Indirect	Total	Cells
Vendor 1	$36,543,000	$15,638,000	$2,394,000	$239,000	$31,653,000	$86,467,000	80
Vendor 2	$38,298,000	$16,436,000	$1,915,000	$239,000	$32,856,000	$89,745,000	64
Vendor 3	$31,277,000	$15,319,000	$1,915,000	$239,000	$28,136,000	$76,886,000	64
Average	$35,373,000	$15,798,000	$2,074,000	$239,000	$30,882,000	$84,365,000	72
Scaled to 2007 $	$47,336,000	$18,815,000	$2,777,000	$321,000	$39,978,000	$109,226,000	

It is recognized that current plans call for the use of dry cooling on the new Gateway unit at this site. The cost and difficulty of using dry cooling on new units is much less than for retrofits. In particular,

- The turbines for the new unit will be operable at backpressures in the 8 in Hga range, with much higher condensing temperatures than are possible for the existing turbines limited to
  5 in Hga.
- The unit can be oriented in such a way that the ACC can be located close to the turbine exhaust allowing short, efficient and inexpensive steam ducting from the turbine to the
  ACC. This is not possible with the existing units.

Effect on Plant Performance

A retrofitted cooling system of either the wet or dry type would have a deleterious effect on the plant net heat rate. This arises from two effects:

1. Considering only the wet system, the power requirements will be higher than the current pumping power requirements for the once-through system. This power is used for the additional circulating pumps and for the cooling tower fans and represents power that must be generated but cannot be sold.
2. The plant will operate at a higher backpressure and therefore a higher heat rate with closed cycle cooling. This effect will be much more pronounced for a dry system than for a wet system.

The additional power requirements are estimated as follows:

Pumping power: As noted in Section 4.1.3, the existing circulating water system will discharge into a sump from which a second set of pumps will draw the water and discharge it to the top of the cooling tower. The circulating water flow rate must be pumped through an additional head rise. This will be estimated at 40 feet to account for the lift out of the sump, the rise to the hot water distribution deck on the top of the tower and the head loss through the circulating water lines. A combined pump/motor efficiency of 75% is assumed. Each of these factors would be refined in a detailed analysis, but these are considered adequate to give a reasonable estimate of the effect of additional operating power on the plant. For the several units at Contra Costa:

Table B-20
Contra Costa Units: Retrofit Additional Pumping Power

Unit	Flow	Head	Eff	Power	Motor
	gpm	ft		kW	MW
6	153,000	40	0.75	1152.4	1.54
7	153,000	40	0.75	1152.4	1.54

Fan power: Similarly cooling tower fan power can be roughly estimated. It is assumed for retrofits on older, lower capacity factor units, the tower would be sized to "low first cost" design since the number of operating hours is low and power penalties are less severe. This is consistent with the assumptions made in the retrofit capital cost estimates. The number of cells will be estimated as one cell per 10,000 gpm of circulating water flow, the fan horsepower at 200 HP and a motor efficiency of 90%. For the Contra Costa units this results in:

Table B-21
Contra Costa Units: Retrofit Fan Power

Unit	Flow	Cells	Eff	Power	Motor
	gpm	n		hp	kW
6	153,000	15	0.9	3,060	2,536
7	153,000	15	0.9	3,060	2,536

This represents a combined, full-load operating power requirement of approximately 8.5 MW or approximately 1.25 % of the plant power rating of 680 MW. The actual annual cost will obviously depend on the capacity factor, the number of hours on-line, and whether some fans are turned off when operating at part load. Also, the cooling system was sized for full load at acceptable backpressures at so-called "1%" ambient conditions, it would be well oversized for nearly the entire year. Therefore, the effect of requiring additional operating power for the pumps and fans coupled with operation at higher heat rate would be an increase in the fuel burned rather than a reduction in plant output.

Heat rate penalty: As seen in the earlier plot of comparative backpressures, the condensing pressure with closed-cycle wet cooling will run typically 0.5 to 1.0 in Hga higher than it would with once-through cooling and increases to about 2.25 in Hga on the hottest days. The effect is less at part load. No information is available to estimate the effect on heat rate resulting from the increased backpressure. However, information from comparable units suggest an increase of at least 0.25% for each 0.1 in Hga increase in backpressure above design might be reasonable. The comparative plot shown earlier suggests that closed cycle cooling will result in increased backpressure throughout the year ranging from 0.5 to 1. in Hga with a corresponding heat rate penalty of 0.5 to 1.%. In the absence of other information, it is assumed to be applicable to the Contra Costa units as well resulting in a heat rate penalty at full load of 0.5 to 1.% for the units at the plant. It should be noted that some estimates on other individual units of similar size and age have been much higher, up to a heat rate increase of as much as 1,000 Btu/kWh for a backpressure increase of 1.5 to 2.5 in Hga.

Capacity Limits

The increased back pressure will likely result in an output restriction at the hottest day. The magnitude of the shortfall will depend on the operating philosophy. If the firing rate is held constant, a 1% heat rate penalty would correspond to roughly a 1% reduction in output which would appear to be a minor effect on output. If, however, it were to be decided that operation at a backpressure of 2.5 in Hga constituted an unacceptable maintenance risk to the turbine, then the firing rate would need to be reduced to hold whatever backpressure was consider acceptable. Information to estimate what the shortfall would be in that case is not available but presumably could be estimated by plant staff based on the information given above.

Maintenance Costs

Commonly used factors for maintenance (labor, materials, chemicals, etc.) for wet cooling systems range from 2. to 3. % of the system capital costs.

For wet systems, the important costs are for water treatment, biofouling control and keeping the basin clean. Using salt water and having salt drift around the plant would require rust control, extra painting, etc. Using the high end of typical factors, assume 3. to 3.5% of the capital cost of the tower. It is unclear how Mirant would allocate these costs between operation and maintenance, but an estimate of 3% of the “average” capital costs for all units of $84 million could amount to approximately $2,500,000 per year.

The deposition of saline drift on the switchyard located on the site will present a serious maintenance problem even with high performance drift eliminators.

Additional Cost Considerations

Although the S&W costs are pretty close to the Maulbetsch Consulting survey’s “Average” difficulty estimate, neither of those estimates can account for any site-specific difficulties which might be encountered at the Contra Costa site. Those items that could cause a retrofit at this site to be in a different, either “High” or “Easy” category include:

- Difficulty in locating the tower
- Unusual site preparation costs
- Significant interferences to the cost of installation of the circulating water lines
- The need for cooling tower plume abatement
- Stringent noise control
- The use of an alternate make-up water

Location of Tower/Unusual Site Preparation Costs/Interferences

With reference to the site plan below, it appears that space would be available for cooling towers, particularly after the construction/laydown areas are no longer needed.

No information is available, however, regarding the suitability of these sites, but a number of items would need to be considered:

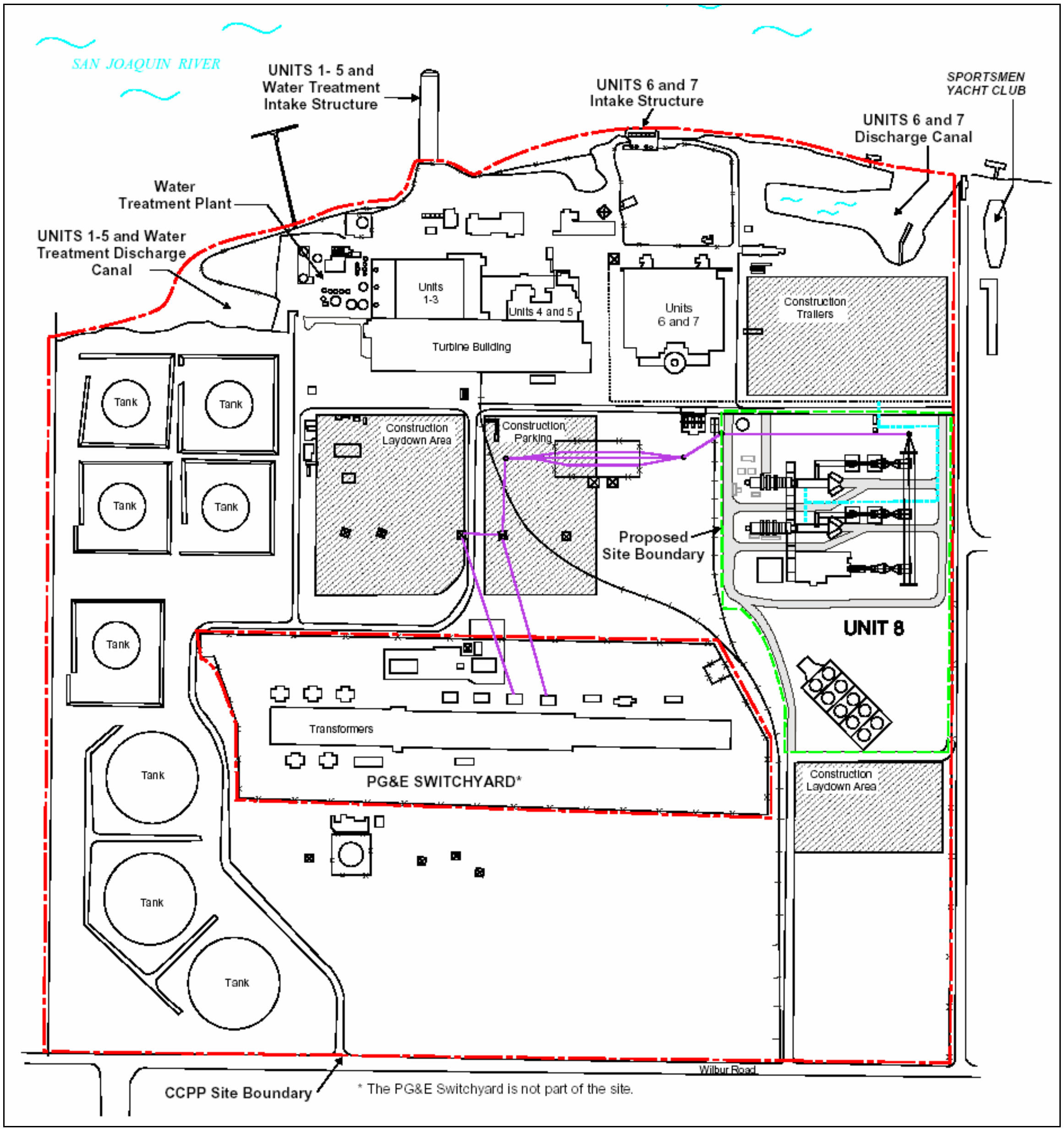


Figure B-17
Contra Costa Site Plan

This location may have constraints, however, including

i. The need to demolish, relocate and rebuild existing structures for some locations.

ii. Unstable soil conditions requiring significant foundation work such as deep pilings to stabilize the towers. This is likely given the location of the plant.

iii. Drift deposition from salt water towers, particularly on the PG&E switchyard shown on the plan.

iv. Underground infrastructure which would make the installation of underground circulating water lines difficult and costly.

v. Remoteness of current intake bays from towers located south of the plant and difficulty in tying into the existing circulating water system.

vi. Possible neighborhood objections to visible plumes, corrosive drift and noise.

vii. The need for PM10 offsets for expected drift from seawater towers.

Plume Abatement

Based on the view in the aerial photo of the neighboring area, it appears that a visible plume could be an issue at this site primarily from an aesthetic viewpoint but possibly also as a safety issue with reference to Highway 160 running to the east of the site. It is possible that a plume abatement tower would be required. Plume abatement towers have an air-cooled section on top of the wet tower. The hot water is pumped to the top of the tower, passes down through the dry section and then discharged onto the hot water distribution deck of the wet section. The air passing across the finned tubes of the dry section mixes with the wet plume coming off the wet section and keeps it from becoming saturated and condensing in the cold atmosphere. The need for a plume abatement tower would increase both the capital cost of the tower itself by a factor of perhaps 2. to 2.5 and the additional pumping power by an additional 30 to 50% due to the greater height to which the hot water must be pumped.

Aesthetics

In addition to any issues with a visual plume, the simple appearance of a cooling tower is sometimes considered an aesthetic affront. In this instance, even though the towers would be visible to neighbors, considering the number, size and bulk of the plant buildings already present, it does not appear that this would present a major problem.

Noise Control

Noise from wet cooling towers comes both from the fans and from the water cascading through the fill. Fan noise can be diminished by fan design or the reduction in air velocity which sometime requires the use of bigger, or more, cells. The water noise is more difficult to reduce and usually requires the construction of sound barriers around the cooling tower. As in the case of the plume abatement question, the aerial photo of the plant and the neighboring area makes it appear that cooling tower noise should not be a serious constraint. It should be noted, however, that noise limitations were imposed at the Crockett plant in Crockett, California on the south shore of the San Francisco Bay. While this was due in part to nearby residential areas, limits over the Bay were also imposed. In case that noise abatement should be required, the capital cost of the tower itself cost might increase from 20 to 40%.

Alternate Sources of Make-Up Water

The use of seawater make-up can introduce intractable problems regarding drift and related maintenance considerations. (See later discussion of drift and PM10.) An alternative can be to purchase reclaimed water from nearby municipal water treatment facilities. The use of reclaimed municipal water has been discussed in conjunction with Gateway and appears to be possible although not preferred.

If the use of reclaimed water for wet cooling tower makeup were to be considered, the distance of sources from the plant, the cost of installing delivery and return pipelines to the remote sources and the time required to obtain permits must be factored into any estimate of the cost.

Shutdown Period

There is often concern over the period of post plant availability during the retrofit construction period. In this instance, it appears that the major part of the construction could be done while the plant is on-line, with shutdown required only for the final tie-in of the circulating water lines to the existing water circuit. There is no information available to estimate how long this might be. However, the operating profiles shown earlier indicate periods of little or no operation. Therefore, it appears that the tie-in could be accomplished with no serious downtime.

Other Environmental Issues

Retrofit to a closed-cycle cooling system introduces some environmental issues which a once-through cooling system does not. These are increased air emissions from the stack and drift from the cooling tower.

Stack Emissions

In an earlier section it was noted that a closed-cycle retrofit increase the unit net output because of heat rate penalties and the use of increased operating power. In this instance these together were estimated at from 1 to 2%. Therefore, the delivery of the same amount of electric power to the grid will require the burning of additional fuel at some location to make up that lost at Contra Costa. Based on the unit heat rate information provided, this does not appear to be major effect in this case. Furthermore, in the discussion of this issue in Chapter 7, it was pointed out that the effect of making up this shortfall was highly variable depending on how and where the replacement per was generated. Therefore, no attempt is made to asses the effect in quantitative terms beyond pointing out that reliable estimates of the shortfall to be expected from full load operation can be made.

Drift

It is assumed that any cooling tower would be equipped with state-of-the-art drift eliminators rated at about 0.0005% of circulating water flow. The following table estimates the amount of drift to be expected from such designs. In addition, as discussed earlier, Federal EPA and State regulations characterize all solids carried off in cooling tower drift as PM10. The cost of offsetting these amount, should it be necessary will vary considerably from site to site as will the severity of the regulatory constraints.

Table B-22
Contra Costa Drift Estimates

Unit	Flow	Drift[1]	Drift	PM10	PM10	Cap. Factor	PM10
	gpm	gpm	lb/hr	lb/hr	tons/year[2]	%	tons/year[3]
6	**153,000**	0.77	382	19.12	83.7	**24.7**	**20.7**
7	**153,000**	0.77	382	19.12	83.7	**24.7**	**20.7**

1. At drift eliminator efficiency of 0.0005%
2. Assumes full load all year
3. At 2006 capacity factor

General Conclusion

On balance, it is concluded that the nature of the likely problems and additional costs to be encountered at Contra Costa would put the retrofit at this site in the "average" to "difficult" category. Based on the results from the Maulbetsch Consulting survey presented above, this would put the project cost in the range of $84 to 130 million. Since the capacity factor for Unit 6 has been below 4% for four years and that for Unit 7 was below 4% in 2006 and only 10% in 2005, a retrofit investments of this magnitude is likely to be inappropriate.

B.3 El Segundo Generating Station El Segundo Power, LLC (NRG Energy, Inc.)

Location

301 Vista Del Mar
El Segundo, CA 90245-3650
33° 54’ 39.26” N; 118° 25’ 29.96” W
Contact: Tim Hemig, 760-710-2144

Figure B-18
El Segundo Site Boundaries

Figure B-19
El Segundo Site View

Plant/Site Information

Unit 3: 335 MW
Unit 4: 335 MW

Table-B23
El Segundo Cooling System Operating Conditions

Unit	MW	Cooling Water flow		Steam flow	Heat duty	Tin	Tex	Range	Tcond	TTD	Backpressure
		gpm	cfs	lb/hr	Btu/hr	F	F	F	F	F	in Hga
3	335	132,400	295	1.500E+06	1.440E+09	63.0	84.8	21.8	91.8	7.0	~1.5
4	335	132,400	295	1.500E+06	1.440E+09	63.0	84.8	21.8	91.8	7.0	~1.5

Table B-24
El Segundo Capacity Factors

Unit	2001	2002	2003	2004	2005	2006	Average
3	24.4%	35.3%	23.7%	8.8%	12.5%	11.6%	**19.4%**
4	56.0%	45.6%	19.7%	7.8%	10.2%	9.5%	**24.8%**

Table B-25
Basis for El Segundo Meteorological Data

El Segundo Temperature Estimates---F					
El Segundo--Records		**Long Beach--Dry Bulb**		**Long Beach--Wet Bulb**	
High	**Low**	**Median of Extreme Highs**	**0.40%**	**Median of Extreme Highs**	**1.00%**
110	**27**	**103**	**94**	**80**	**72**

In the absence of complete data for El Segundo, the annual averages and duration curves will be based on Long Beach data.

Temperature	Max.	Average	Min.
El Segundo inlet, ºF	73	65	55
Atmos. wet bulb, ºF	70	57	27
Atmos. dry bulb, ºF	110	63	30

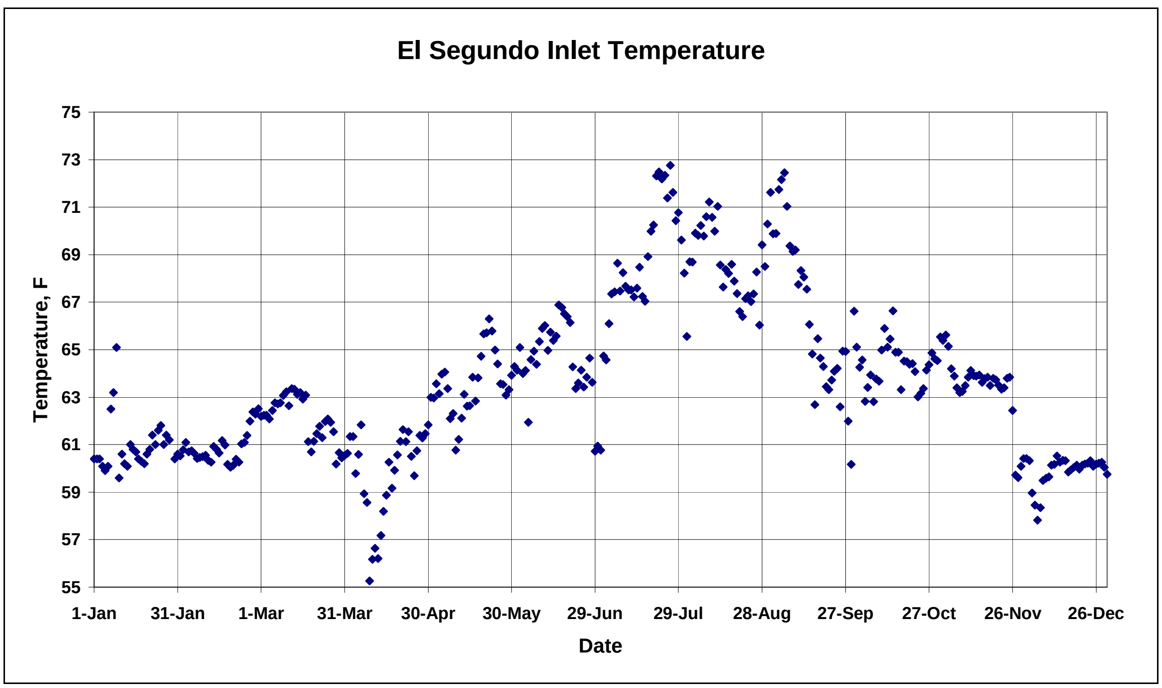


Figure B-20
Inlet Temperature Plot for Year

Plant Operating Data

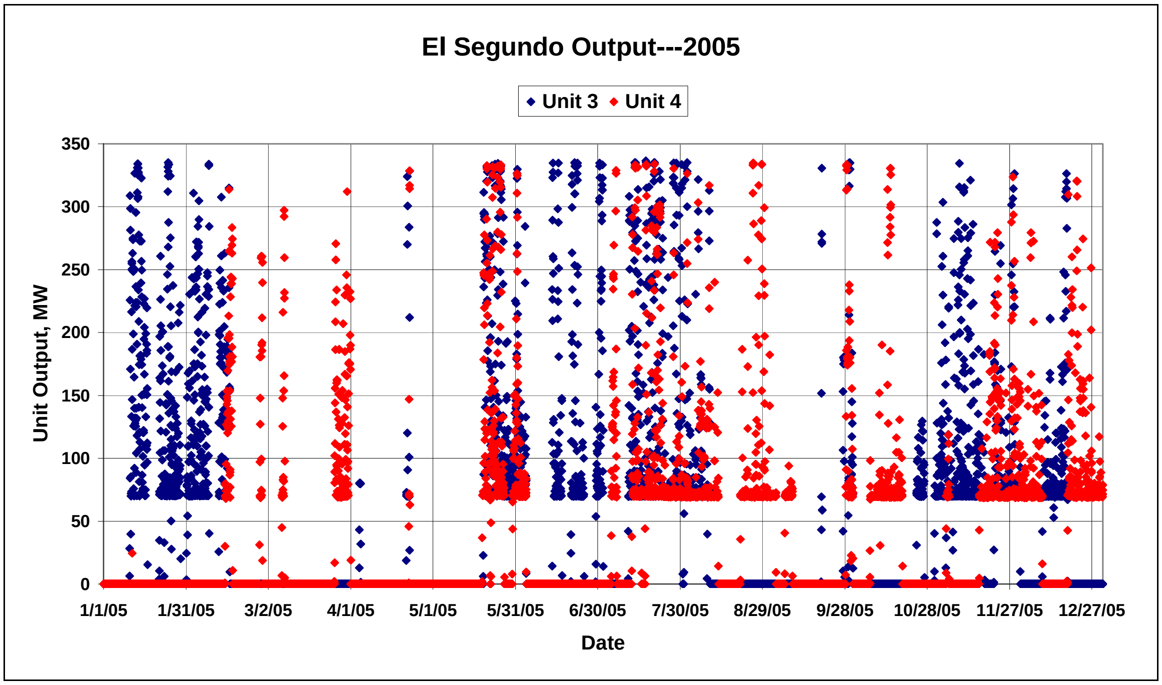


Figure B-21
El Segundo Operating Profile

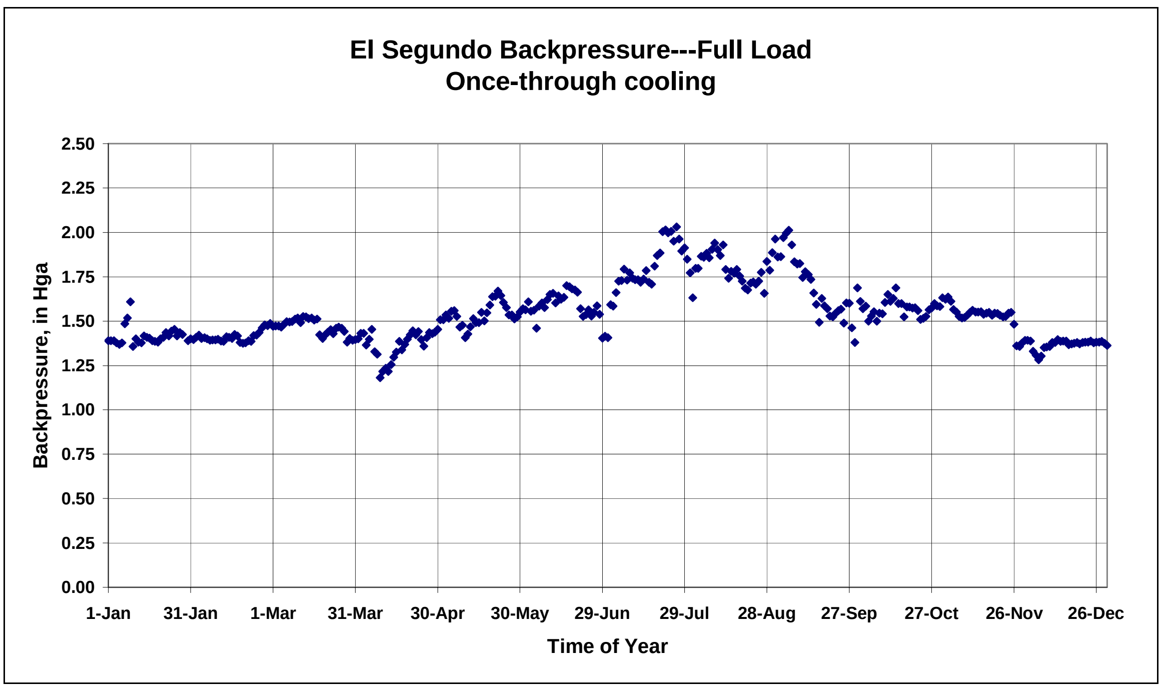


Figure B-22
El Segundo Backpressure Variation––Once-Through Cooling, Full Load

Cooling Tower Assumptions/Design

Wet cooling spec (example)

- Tower type: mechanical draft, counterflow, FRP construction
- Make-up water source: Sea water; 35,000 ppm salinity
- Operating cycles of concentration: n = 1.5
- Evaporation rate: Units 3 and 4--- ~ 3,350 gpm each
- Make-up rate (@ n = 1.5): Units 3 and 4--- ~ 10.050 gpm each
- Blowdown (@ n = 1.5): Units 3 and 4--- ~ 6,700 gpm each

Table B-26

Unit	Ambient Wet Bulb	Range	Approach	TTD	Tcond	Backpressure
	F	F	F	F	F	in Hga
3	72	21.8	10	7	110.8	~ 2.65
4	72	21.8	10	7	110.8	~ 2.65

Tower Design Specs (Full Load)

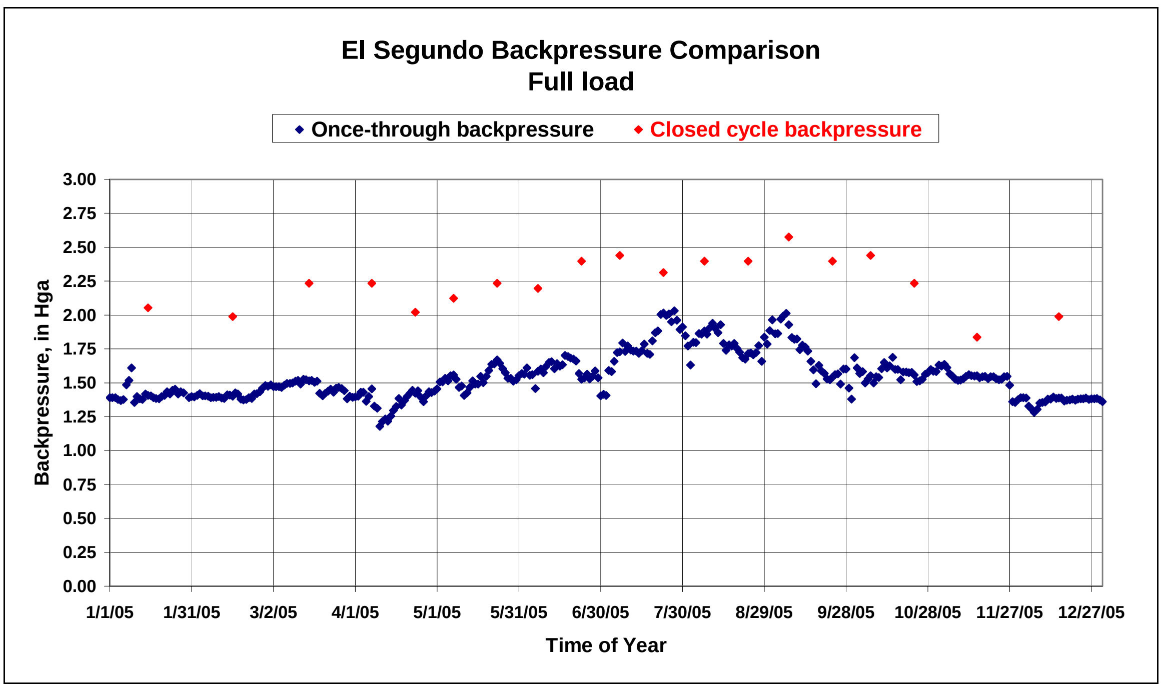


Figure B-23
Backpressure Comparisons––Full Load for Year

Wet Retrofit Costs

Table B-27
S&W Cost Estimates

S&W Costs---escalated to 2007; x 1.07 for seawater					
Unit	**Labor**	**Material**	**Equipment**	**Indirect**	**Total**
3	**$9,700,000**	**$5,656,000**	**$9,608,000**	**$14,479,000**	**$39,443,000**
4	**$9,700,000**	**$5,656,000**	**$9,608,000**	**$14,479,000**	**$39,443,000**
Plant Total	**$19,400,000**	**$11,312,000**	**$19,216,000**	**$28,958,000**	**$78,886,000**

Table 2-8
Maulbetsch Consulting Survey Estimates

Maulbetsch Consulting Survey; escalated to 2007 $; x 1.07 for salinity			
Unit	**Easy**	**Average**	**Difficult**
3	**$21,846,000**	**$36,410,000**	**$56,270,000**
4	**$21,846,000**	**$36,410,000**	**$56,270,000**
Plant Total	**$43,692,000**	**$72,820,000**	**$112,540,000**

Dry Cooling

Similar cost estimates can be made for a dry cooling retrofit. The basic assumption is that for plants with low capacity factors, they must be available to produce close to full load on the hottest days of the year when the system load is at its peak.

- Direct dry cooling: forced, mechanical-draft air-cooled condenser
- Steam flow: 1,500,000 lb/hr (Units 3 and 4)
- Design dry bulb: 98.5ºF (mid-way between 0.4% dry bulb and median of extreme highs)
- Design turbine exhaust pressure: 4.5 in Hga (based on assumption that turbines of this age and design trip at 5 in Hga and that the plant would not wish to reduce output on the hottest days)
- Corresponding condensing temperature: 130°F

Therefore, ACC design ITD ($T_{condensing}$ - $T_{design\ ambient}$) = 130°F – 98.5°F = **31.5°F**

Dry Cooling Retrofit Costs

AC costs can be roughly estimated from EPRI Report No. 1005358; "Comparison of Alternate Cooling Technologies for U.S. Power Plants", August, 2004.

Vendor information for a design of:

Steam flow:	1,500,000 lb/hr (Units 3 and 4)
ITD:	31.5°F
Price:	2007 $

Table B-29
Dry Cooling Retrofit Cost Estimates––Units 3 and 4

Source/Basis	Equipment	Erection	Electrical	Duct Work	Aux. cool	Total Direct	Indirects	Total	Cells
Vendor A (adjusted)	$28,924,000	$12,346,000	$1,852,000	$265,000	$3,175,000	$46,561,000	$27,005,000	$73,566,000	62
Vendor B	$31,746,000	$13,580,000	$1,587,000	$265,000	$3,527,000	$50,705,000	$29,409,000	$80,115,000	53
Vendor C	$26,279,000	$12,875,000	$1,587,000	$265,000	$2,998,000	$44,004,000	$25,522,000	$69,526,000	53
Average	$28,983,000	$12,933,667	$1,675,333	$265,000	$3,233,333	$47,090,000	$27,312,000	$74,402,333	
2007$	$33,599,240	$14,993,664	$1,942,170	$307,208	$3,748,320	$54,590,216	$31,662,094	$86,252,696	

The major difficulty for dry cooling, in addition to very high cost, is the lack of adequate space for the ACC and the distance of candidate locations from the turbine halls. ACC's are normally sited quite close to the turbine exhaust to minimize the length (and therefore the cost and the steam side pressure drop) of the steam duct. Assuming a 55 cell ACC, which would normally be arranged in an 11 x 5 configuration, the dimensions would be on the order of 550 feet by 250 feet.   There is no place n the site, within reasonable distance of the turbine hall is available for such a structure. Therefore, dry cooling retrofit was not considered further at El Segundo.

Effect on Plant Performance

A retrofitted cooling system of either the wet or dry type would have a deleterious effect on the plant net heat rate. This arises from two effects:

1. Considering only the wet system, the power requirements will be higher than the current pumping power requirements for the once-through system. This power is used for the additional circulating pumps and for the cooling tower fans and represents power that must be generated but cannot be sold.
2. The plant will operate at a higher backpressure and therefore a higher heat rate with closed cycle cooling. This effect will be much more pronounced for a dry system than for a wet system.

The additional power requirements are estimated as follows:

Pumping power: As noted in Section 4.1.3, the existing circulating water system will discharge into a sump from which a second set of pumps will draw the water and discharge it to the top of the cooling tower. The circulating water flow rate must be pumped through an additional head rise. This will be estimated at 40 feet to account for the lift out of the sump, the rise to the hot water distribution deck on the top of the tower and the head loss through the circulating water lines. A combined pump/motor efficiency of 75% is assumed. Each of these factors would be refined in a detailed analysis, but these are considered adequate to give a reasonable estimate of the effect of additional operating power on the plant. For the two units at El Segundo:

Table B-30

Segundo Units: Retrofit Additional Pumping Power

Unit	Flow	Head	Eff	Power	Motor
	gpm	ft		kW	MW
3	132,400	40	0.75	997.3	1.33
4	132,400	40	0.75	997.3	1.33

Fan power: Similarly cooling tower fan power can be roughly estimated. It is assumed for retrofits on older, lower capacity factor units, the tower would be sized to "low first cost" design since the number of operating hours is low and power penalties are less severe. This is consistent with the assumptions made in the retrofit capital cost estimates. The number of cells will be estimated as one cell per 10,000 gpm of circulating water flow, the fan horsepower at 200 HP and a motor efficiency of 90%. For the El Segundo units this results in:

Table B-31
El Segundo Units: Retrofit Fan Power

Unit	Flow	Cells	Eff	Power	Motor
	gpm	n		hp	kW
1	132,400	13	0.9	2,648	2,195
2	132,400	13	0.9	2,648	2,195

This represents a combined, full-load operating power requirement of approximately 7 MW or slightly more than 1.0 % of the plant power rating of 670 MW. The actual annual cost will obviously depend on the capacity factor, the number of hours on-line, and whether some fans are turned off when operating at part load. Also, the cooling system was sized for full load at acceptable backpressures at so-called "1%" ambient conditions; it would be well oversized for nearly the entire year. Therefore, the effect of requiring additional operating power for the pumps and fans coupled with operation at higher heat rate would be an increase in the fuel burned rather than a reduction in plant output under most operating conditions. However, at full load a capcity reduction would be incurred..

In this context, it should be noted that some plants guarantee an available capacity and are paid for having this capacity available at some amount per MW. If the effect of the retrofit is to reduce the available capacity because of the increased operating power for pumps and fans and because of an increased heat rate, the capacity that could be guaranteed would be reduced with a corresponding reduction in the capacity payments.

Heat rate penalty: As seen in the earlier plot of comparative backpressures, the condensing pressure with closed-cycle wet cooling will run typically 0.5 to 1.0 in Hga higher than it would with once-through ocean cooling and increases to about 2.5 in Hga on the hottest days. The effect is less at part load. No information is available to estimate the effect on heat rate resulting from the increased backpressure. However, information from comparable units suggest an increase of at least 0.25% for each 0.1 in Hga increase in backpressure above design might be reasonable. The comparative plot shown earlier suggests that closed cycle cooling will result in increased backpressure throughout the year ranging from 0.5 to 1. in Hga with a corresponding heat rate penalty of 0.5 to 1.%. In the absence of other information, it is assumed to be applicable to the El Segundo units as well resulting in a heat rate penalty at full load of 0.5 to 1.% for the units at the plant. It should be noted that some estimates on other individual units of similar size and age have been much higher, up to a heat rate increase of as much as 1,000 Btu/kWh for a backpressure increase of 1.5 to 2.5 in Hga.

A 1% heat rate penalty, combined with a 1.% penalty associated with additional operating power requirements, sums to a 2.% output reduction or a 13.5 MW shortfall at full load.

Maintenance Cost

Commonly used factors for maintenance (labor, materials, chemicals, etc.) for wet cooling systems range from 2. to 3. % of the system capital costs. For wet systems, the important costs are for water treatment, biofouling control and keeping the basin clean. Using salt water and having salt drift around the plant would require rust control, extra painting, etc. Using the high end of typical factors, assume 3. to 3.5% of the capital cost of the tower. It is unclear how El Segundo would allocate these costs between operation and maintenance, but an estimate of 3% of the "average" capital costs for all units of $30 million could amount to approximately $1,000,000 per year.

Additional Cost Considerations

Although the S&W costs are pretty close to the Maulbetsch Consulting survey's "Average" difficulty estimate, neither of those estimates can account for any site-specific difficulties, which might be encountered at the El Segundo site. Those items that could cause a retrofit at this site to be in a different, either "Difficult" or "Easy" category include:

- Difficulty in locating the tower
- Unusual site preparation costs
- Significant interferences to the cost of installation of the circulating water lines
- The need for cooling tower plume abatement
- Stringent noise control
- The use of an alternate make-up water

Location of Tower/Unusual Site Preparation Costs/Interferences

The primary difficulty at this site is finding a place to locate the cooling tower. Two possibilities appear to exist.

1. an area south of the Units 3 and 4 buildings to the west of the switch yard which currently appears to be a parking area.
2. a bermed area at the south end of the site with two large oil tanks which are longer in use.

Both locations have serious drawbacks. The first conflicts with an existing, operating retention basin and the natural gas metering and pipeline infrastructure, both of which would have to be relocated. The cost of installing the new basin and the associated flow lines and re-routing the natural gas system would add to the cost of the project. Additionally, the soil at the site of the existing basin has known contamination from the time when SCE owned and operated the facility and would require remediation or off-site disposal to re-use this area for cooling towers. Additional costs from this equipment relocation and remediation are likely not accounted for in the "Difficult" cost category.

The second location would encounter significant community opposition due to its proximity to a high-value residential neighborhood adjacent to the south boundary of the site. This was made very apparent during the repowering case before the CEC during 2000-2004. Due to the size, noise, and visual resource issues at this location, it is unlikely that even extensive screening by berming or landscaping would be sufficient to allow for cooling towers to be sited in this area.

Therefore, the only potential space for cooling towers would be at the parking lot and retention basin location to the south of Unit 4, assuming the affected existing equipment could be relocated and the soil remediated.

No information is available on site geology or soil characteristics. If, as is sometimes the case in near coastal areas, the ground is saturated and unstable, the installation of the tower basin and the circulating water lines may be difficult.

There is no information on underground infrastructure from which to estimate the likelihood of interferences to the installation of circulating water lines, however, it is known that the parking lot and retention basin area considered for tower location has underground wastewater and natural gas pipeline infrastructure.

Neighborhood Issues––Plume Abatement

The aerial photo below (Figure B-24) provides some information on the neighboring area. The plant is bounded on the West by the beach, on the East by a heavily traveled highway (Vista del Mar) and on the South by a residential neighborhood of high value properties (Manhattan Beach). Additionally, the Los Angeles International Airport (LAX) is located approximately 2 miles north of ESGS. Sensitive equipment, including SCE electrical transmission switchgear, is also located in close proximity to the proposed tower location.

Aesthetic sensitivities in beach areas, safety concerns on high traffic roadways and neighborhood resistance to visual impairments all combine to make it highly likely that a visible cooling tower plume would be unacceptable. Therefore, this study assumes that a plume abatement tower would be required at this site, however as discussed below, plume abated towers are not logistically feasible at the ESGS facility. This could result in a significant feasibility issue for retrofitting cooling towers at this site.

Figure B-24
El Segundo Neighboring Areas

Plume abatement towers have an air-cooled section on top of the wet tower. The hot water is pumped to the top of the tower, passes down through the dry section and is then discharged onto the hot water distribution deck of the wet section. The air passing across the finned tubes of the dry section mixes with the wet plume coming off the wet section and keeps it from becoming saturated and condensing into a visible plume in the cold atmosphere. If one should be required, it would increase both the capital cost of the tower itself by a factor of perhaps 2. to 2.5 and the additional pumping power by an additional 30 to 50% due to the greater height to which the hot water must be pumped.

However, the need for a plume abatement tower design raises the following issues.

1. The need for a plume abatement tower would increase both the capital cost of the tower itself by a factor of perhaps 2. to 2.5 and, therefore, increase the total project cost by perhaps 30%.
2. The additional pump and fan power would increase due to the increased tower height and the higher airflow required for the dry section. Quantitative information is not available to estimate the power requirements precisely but it is reasonable to expect a 50% increase in pumping power (60 ft. vs. 40 ft.) and perhaps a 35% increase in fan power.

3. The tower height would increase by 20 to 30 feet and would then exceed the local height limits of 45 feet as specified by plant staff. It is not known whether this would completely rule out the use of a plume-abated tower at the site or would still be allowable but require extensive screening by berming or landscaping or both.
4. Plume abated towers require greater lineal footprint than conventional cooling towers because they must be placed in an in-line configuration and cannot be configured in a back to back configuration. This arrangement necessitates more space than is available at the ESGS facility and therefore plume abated towers are not feasible at this location.

Neighborhood Issues––Aesthetics

In addition to any issues with a visual plume, the simple appearance of a cooling tower is sometimes considered an aesthetic affront. In this instance, even though the towers would be readily visible from the beach, considering the number, size and bulk of the plant buildings already present, it is possible that conformity with coastal zone and city requirements could be attained, but not likely without required visual mitigation.

As discussed earlier in the section on tower location, it apparently has been agreed with the neighborhood to the South that the area in which the two existing, unused fuel tanks are located would not be used in any way that would make equipment visible from the nearby residences. Therefore, the location of a tower at that location is not feasible even with berming or landscaping for visual shielding.

Neighborhood Issues––Noise Control

Noise from wet cooling towers comes both from the fans and from the water cascading through the fill. Fan noise can be diminished by fan design or the reduction in air velocity, which sometime requires the use of bigger, or more, cells. The water noise is more difficult to reduce and usually requires the construction of sound barriers around the cooling tower. As noted earlier in the discussion of the visible plume, the plant site abuts both a residential neighborhood and the beach. Both areas, but particularly the closest residences, will be sensitive to any increased noise from the plant. Plant staff indicated that a maximum of a 2 dBa increase in sound level would be permitted at the site boundary. Without site monitoring information, it is difficult to conclude what degree of noise modification, if any, might be required. However, if significant low noise design modification to the fans or the installation of sound barriers were required, the cost increase would be significant (of the order of 10 to 25% of the installed cost of the tower). Because the cooling tower location would in any instance be right up against the property line, it is assumed that noise abatement equipment is required at a minimum, and the costs are factored in accordingly.

Alternate Sources of Make-Up Water

The use of seawater make-up can introduce problems regarding drift and related maintenance considerations. (See later discussion of drift and PM10.) An alternative can be to purchase reclaimed water from nearby municipal water treatment facilities. In this instance, the proximity of Hyperion (approximately ¾ miles north of the plant as shown in the photo above) with large quantities of reclaimable municipal wastewater makes this alternative feasible. A supply and return line with a capacity of approximately 10,000 gpm for the make-up line and perhaps 2,000 gpm for the return line would need to be installed between Hyperion and the plant. There is no information available to estimate the cost of this but costs of over $1,000,000 per mile would not be uncommon. Other issues include whether or not sufficient reclaimed water capacity is available nearby and the presence of ammonia in the water and hence compatibility with existing condenser materials. This alternative would result in greater cost relative to the saltwater towers in this study due to the necessary purchase of the reclaimed water for plant operations.

The possibility of using this water at another plant was also studied in 1995 by two firms. Both identified the presence of ammonia in the water as a problem due to incompatibility with the use of Admiralty brass in the existing condensers. Ammonia stripping was feasible at a cost. The elimination of maintenance and drift problems that would be incurred if seawater make-up were used would appear to make this an attractive alternative if the water is in fact available.

Shutdown Period

There is often concern over the period of lost plant availability during the retrofit construction period. In this instance, it appears that the major part of the construction could be done while the plant is on-line, with shutdown required only for the final tie-in of the circulating water lines to the existing water circuit. There is no information available to estimate reliably how long this might be. A plausible estimate might be one to two months.

This may or may not be a significant issue. It would appear from the operating profile for 2005 (Figure B-21) that, if the tie-in were done one unit at a time, there would be little, if any, interference with the actual plant operation. However, although the annual capacity factor is low, the plant is required to be “available all year” pursuant to commercial arrangements to have plant capacity available to the grid operator. Therefore, some accommodation to the current obligations would have to be included as part of the retrofit process to avoid financial impacts from the one to two month plant downtime for retrofit. Under current plant commercial arrangements, this extended plant outage would result in loss of revenue to the plant.

Other Environmental Issues

Retrofit to a closed-cycle cooling system introduces some environmental issues, which a once-through cooling system does not. These are increased air emissions from the stack and drift from the cooling tower.

Stack Emissions

In an earlier section it was noted that a closed-cycle retrofit increase the unit net output because of heat rate penalties and the use of increased operating power by approximately 2%, although, as noted in the earlier discussion, even higher heat rate effects have been reported for some turbines of similar age and design. . Therefore, the delivery of the same amount of electric power to the grid may require the burning of additional fuel at some location to make up that lost at El Segundo. If the relatively low frequency of operation at El Segundo implies that when it does operate, it does so at full load then the lost power, estimated to be approximately 13.5 MWs, will have to be made up elsewhere. On the other hand, if operation is normally at partial load, the output might simply be increased at the site except on the very hottest days when the units might be backpressure limited. Therefore, no attempt is made to assess the effect in quantitative terms beyond pointing out that reliable estimates of the shortfall to be expected from full load operation can be made.

Drift

It is assumed that any cooling tower would be equipped with state-of-the-art drift eliminators rated at about 0.0005% of circulating water flow. In this case, that would amount to less than 0.7 gpm from each unit. However, even with these state-of-the-art controls, two issues must be considered.

1. Local air quality regulations governing fine particulate (PM-10) emissions.
2. The effect of drift on nearby on-site equipment and neighboring off-site areas.

In both cases, the quality of the make-up water is an important factor. If the makeup were seawater, the tower would typically be operated at 1.5 cycles of concentration resulting in a circulating water and drift salinity of over 50,000 ppm TDS. If the makeup is reclaimed municipal water, the tower would operate at much higher cycles of concentration (typically 5 to 10) but the circulating water and drift salinity would be much less.

PM-10: The following table estimates the amount of drift to be expected from such designs. As discussed earlier, Federal EPA and State regulations characterize all solids carried off in cooling tower drift as PM-10. The table estimates the rate of PM-10 emissions at full load and the average rate at the 2006 capacity factor for each unit.

Table B-32
El Segundo Drift Estimates

Unit	Flow	Drift[1]	Drift	PM10	PM10	Cap. Factor	PM10
	gpm	gpm	lb/hr	lb/hr	tons/year[2]	%	tons/year[3]
3	132,400	0.66	331	16.54	72.5	11.6	8.4
4	132,400	0.66	331	16.54	72.5	9.5	6.9

1. At drift eliminator efficiency of 0.0005%
2. Assumes full load all year
3. At 2006 capacity factor

The cost of offsetting this amount, should it be necessary will vary considerably from site to site as will the severity of the regulatory constraints. This level of new PM-10 emissions in the Los Angeles air basin would be considered significant. A new source of PM-10 of this magnitude may require mitigation to bring levels down to insignificance pursuant to CEQA or other environmental requirements. Mitigation is often in the form of emission offsets. However, PM-10 offsets are in very short supply in this air basin and, even if available, would be quite costly. The present market price for PM-10 offsets is approximately $125,000 per lb per day. The required offsets are calculated as the full load emission rate for peak monthly operation (assumed to be 50% capacity factor). For this plant and the peak monthly 50% operating level, the total cost on that basis is approximately $50 million. Such a peak monthly 50% capacity factor would be a new and undesirable operating limitation, and therefore it may be necessary to preserve full dispatch capability for a peak month resulting in mitigation costs of $100 million or more, depending on market prices and availability.

Other drift effects In addition to the PM10 considerations, there is the issue of the effect of drift deposition, particularly in the case of saline make-up, both for on-site equipment and off-site areas.

Possible off-site effects would include effects on residential property and automobiles in the neighborhood to the South and on equipment or even process chemistry in the Chevron refinery to the East. Given that the entire area in a near-coastal area with naturally high levels of salt drift from the ocean surf, there may not be significant incremental effects, but some amount of off-site monitoring, before and after the retrofit would likely be required. Regardless, this would be a new and more visible salt drift effect that would likely require community mitigation and equipment protection to be permittable.

On-site effects are of greater concern. The switchyard may be subject to salt drift deposition and insulator flashover requiring increased maintenance to wash down the insulators more frequently. This effect may be significant enough to require major equipment protection upgrades or even relocation, of which no costs were included in this retrofit estimate.

The concern over drift effects would be greatly reduced if reclaimed water were used. Typical TDS levels would vary from a few 100 to no more than 1000 ppm. At 5 to 10 cycles of concentration, the drift salinity would never exceed 10,000 ppm and would have a proportionately lower environmental effect. However, as noted in an earlier section, the cost of providing reclaimed water to the site for cooling tower make-up, even if available, adds significantly to the cost of the project.

General Conclusion

On balance, it is concluded that the nature of the likely problems and additional costs to be encountered at El Segundo would put the retrofit at this site in a “difficult” category. Based on the results from the Maulbetsch Consulting survey presented above, this would put the project cost in the range of $110 to 115. million. Further a likely requirement for plume abatement with insufficient space to accommodate the necessary hardware could result in a significant permitting issue at this facility.

It is noteworthy that the California Energy Commission, in their review of the Application for Certification (00-AFC-14) of the El Segundo Power Redevelopment Project in February, 2005 approved once-through cooling with seawater for the project and “rejected other alternative cooling systems because Staff considered them infeasible.” This conclusion was reached on the basis that “the site is not large enough” and that the alternative technologies “would cause adverse noise and visual impacts.”

B.4 Encina Power Station Cabrillo Power I LLC (NRG Energy, Inc.)

Location

4600 Carlsbad Boulevard
Carlsbad, CA 92008-4301
33° 08' 13.92" N; 117° 20' 05.12" W
Contact: Tim Hemig, 760-710-2144

Figure B-25
Encina Boundaries and Neighborhood

Figure B-26
Encina Site View

Plant/Site Information

Unit 1: 107 MW
Unit 2: 104 MW
Unit 3: 110 MW
Unit 4: 287 MW
Unit 5: 315 MW

Table B-33
Encina Cooling System Operating Conditions

Unit	MW	Cooling Water flow		Steam flow	Heat duty	Tin	Tex	Range	Tcond	TTD	Backpressure
		gpm	cfs	lb/hr	Btu/hr	F	F	F	F	F	in Hga
1	107	48,000	107	5.632E+05	5.350E+08	66.8	89.1	22.3	96.1	7.0	1.71
2	104	48,000	107	5.474E+05	5.200E+08	66.8	88.5	21.7	95.5	7.0	1.69
3	110	48,000	107	5.789E+05	5.500E+08	66.8	89.7	22.9	96.7	7.0	1.74
4	287	200,000	445	1.511E+06	1.435E+09	66.8	81.2	14.4	88.2	7.0	1.35
5	315	208,000	463	1.658E+06	1.575E+09	66.8	82.0	15.2	89.0	7.0	1.38

Table B-34
Encina Capacity Factors

Unit	MW (net)	Capacity Factor (%)						
		2001	2002	2003	2004	2005	2006	Average
1	95	41.1%	16.8%	13.8%	20.4%	15.6%	4.6%	14%
2	104	40.2%	19.4%	15.5%	23.7%	17.3%	9.6%	17%
3	110	46.5%	18.8%	21.1%	34.2%	18.7%	11.6%	21%
4	300	56.5%	33.1%	33.7%	43.9%	30.7%	17.9%	32%
5	325	42.6%	34.6%	38.5%	43.5%	19.9%	18.7%	31%

Table B-35
Encina Meteorological Data

Temperature	Max.	Average	Min.
Encina inlet temp., ºF	78	66.8	55
Atmos. wet bulb, ºF	70	57	38
Atmos. dry bulb, ºF	96	69	42

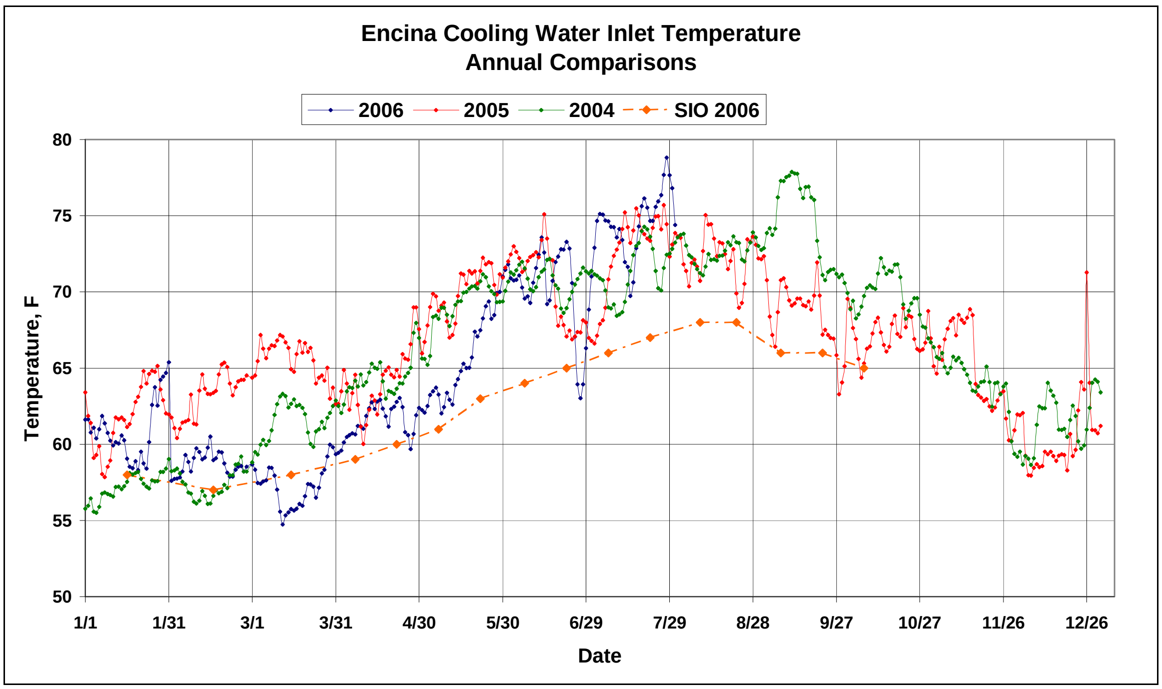


Figure B-27
Encina Inlet Temperatures

Plant Operating Data

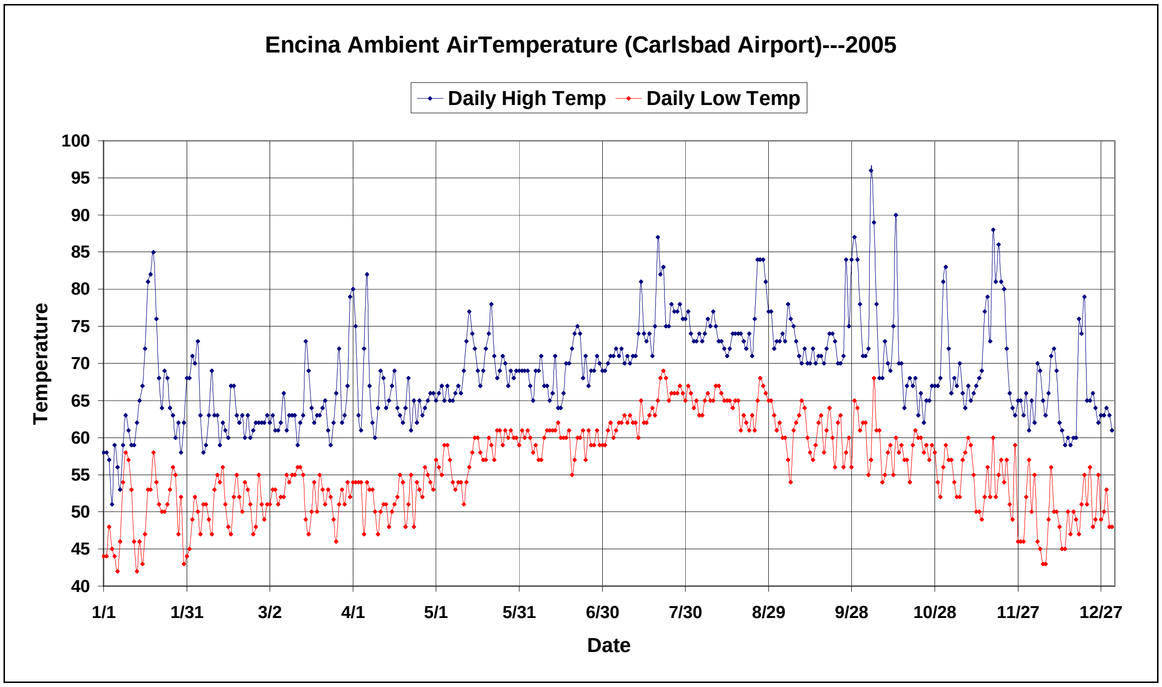


Figure B-28
Encina Ambient Temperature Data (from Carlsbad Airport)–2005

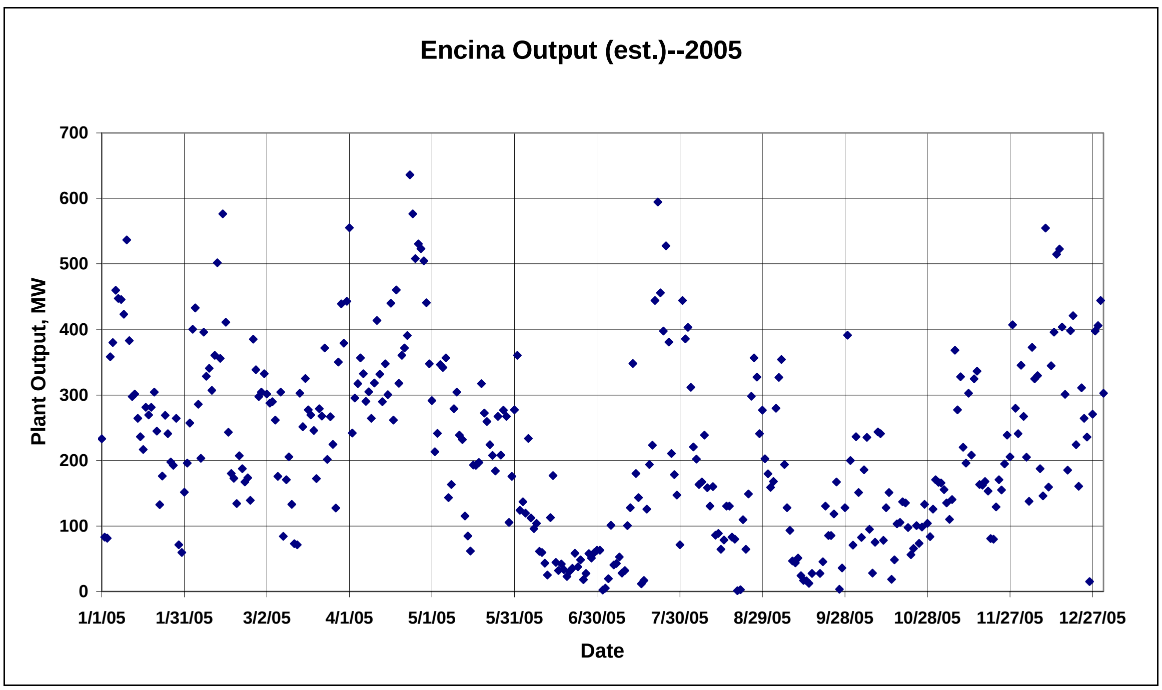


Figure B-29
Encina Plant Output–2005

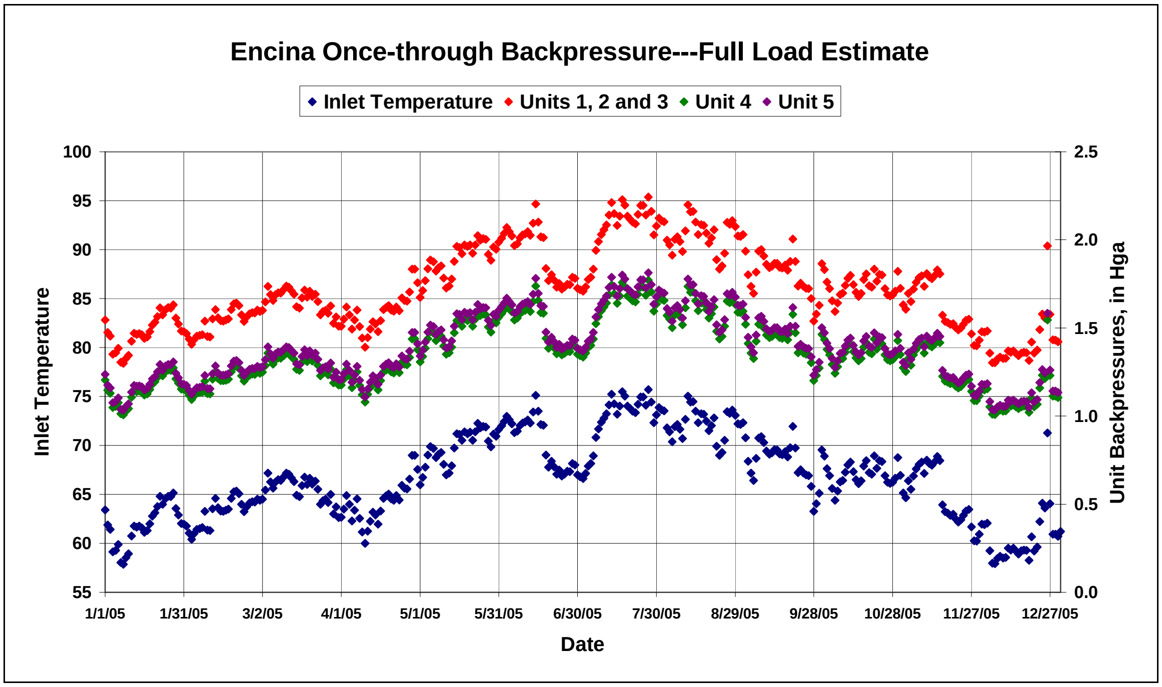


Figure B-30
Encina Backpressure for Once-Through Cooling (Full Load)

Cooling Tower Assumptions/Design

Wet cooling spec (example)

- Tower type: mechanical draft, counterflow, FRP construction
- Make-up water source: Sea water; 35,000 ppm salinity
- Operating cycles of concentration: n = 1.5
- Evaporation rate: Units 1, 2 and 3--- ~ 10,500 gpm each
  Unit 4--- ~ 29,000 gpm
  Unit 5--- ~ 32,000 gpm
- Make-up rate (@ n = 1.5): Units 1, 2 and 3--- ~ 31,500 gpm each
  Unit 4--- ~ 87,000 gpm
  Unit 5--- ~ 96,000 gpm
- Blowdown (@ n = 1.5): Units 1, 2 and 3--- ~ 21,000 gpm each
  Unit 4--- ~ 58,000 gpm
  Unit 5--- ~ 64,000 gpm

Tower design conditions are for all circulating water flows and condenser specifications unchanged, an assumed tower approach of 10°F and a peak wet bulb temperature of 70°F.

Table B-36
Cooling Tower Design Conditions for Full Load on Hot Day

Unit	Ambient Wet Bulb	Range	Approach	TTD	Tcond	Backpressure
	F	F	F	F	F	in Hga
1	70	22.3	10	7	109.3	~ 2.5
2	70	21.7	10	7	108.7	~ 2.5
3	70	22.9	10	7	109.9	~ 2.5
4	70	14.4	10	7	101.4	~ 2.0
5	70	15.2	10	7	102.2	~ 2.0

Therefore, on the hottest day at full load, all units would operate at a backpressure of approximately 2.5 in Hga. Over the course of the year when the ambient wet bulb temperature would be lower, the backpressure would vary as indicated in the following figure. A comparison is given to the backpressure estimated with once-through cooling and indicates that the backpressure would normally be elevated by 0.5 to 1. in Hga.

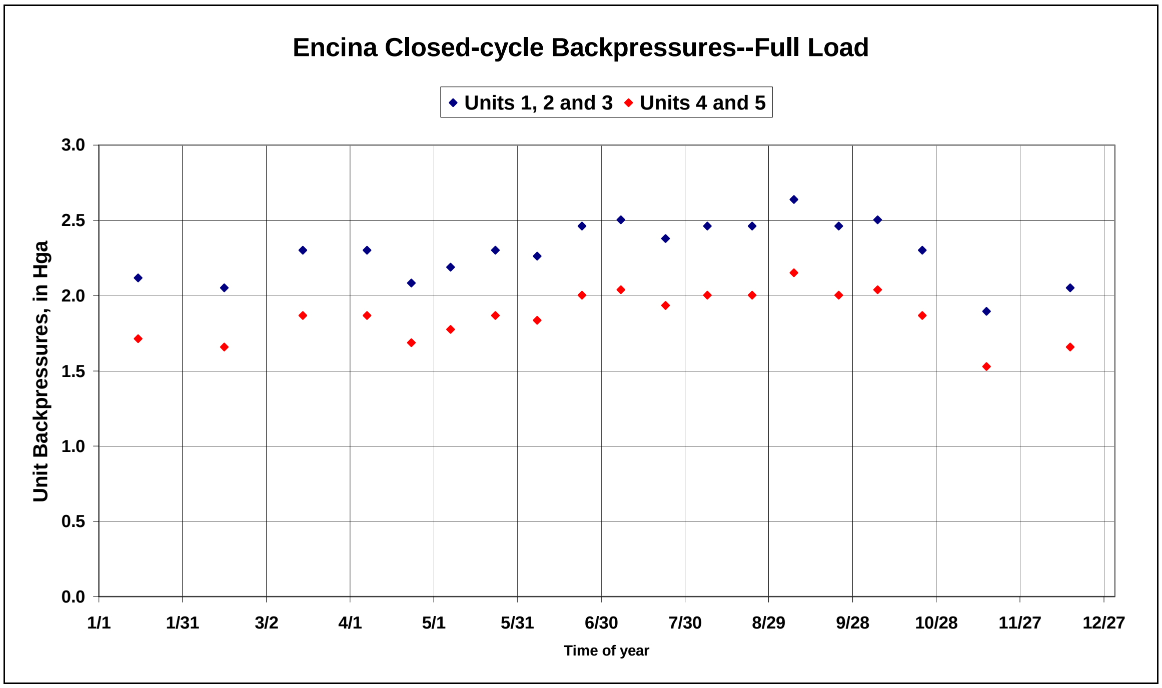


Figure B-31
Closed-Cycle Backpressure Comparison

Wet Retrofit Costs

Table B-37
S&W Estimated Costs

S&W Costs---escalated to 2007; x 1.07 for seawater					
Unit	Labor	Material	Equipment	Indirect	Total
1	$3,337,000	$1,947,000	$3,308,000	$4,983,000	$13,575,000
2	$3,337,000	$1,947,000	$3,308,000	$4,983,000	$13,575,000
3	$3,337,000	$1,947,000	$3,308,000	$4,983,000	$13,575,000
4	$13,062,000	$7,618,000	$12,944,000	$19,502,000	$53,126,000
5	$13,322,000	$7,761,000	$13,202,000	$19,885,000	$54,171,000
Plant Total	$36,395,000	$21,220,000	$36,070,000	$54,336,000	$148,022,000

Table B-38
Maulbetsch Consulting Survey Estimates

Maulbetsch Consulting Survey; escalated to 2007 $; x 1.07 for salinity			
Unit	Easy	Average	Difficult
1	$7,850,000	$13,083,000	$20,219,000
2	$7,850,000	$13,083,000	$20,219,000
3	$7,850,000	$13,083,000	$20,219,000
4	$30,732,000	$51,221,000	$79,159,000
5	$31,325,000	$52,208,000	$80,685,000
Plant Total	$85,607,000	$142,678,000	$220,501,000

Dry Cooling

Similar cost estimates can be made for a dry cooling retrofit. The basic assumption is that for plants with low capacity factors, they must be available to produce close to full load on the hottest days of the year when the system load is at its peak.

- Direct dry cooling: forced, mechanical-draft air-cooled condenser
- Steam flow: ~ 560,000 lb/hr (Units 1, 2 and 3, full load)

  ~ 1,500,000 lb/hr (Unit 4, full load)

  ~ 1,700,000 lb/hr (Unit 5, full load)
- Design dry bulb: 96°F (mid-way between 0.4% dry bulb and median of extreme highs)
- Design turbine exhaust pressure: 4.5 in Hga (based on assumption that turbines of this age and design trip at 5 in Hga and that the plant would not wish to reduce output on the hottest days)
- Corresponding condensing temperature: 130°F

Therefore, ACC design ITD ($T_{condensing}$ - $T_{design\ ambient}$) = 130°F – 96°F = 34°**F**

Dry Cooling Retrofit Costs

AC costs can be roughly estimated from EPRI Report No. 1005358; "Comparison of Alternate Cooling Technologies for U.S. Power Plants", August, 2004.

Vendor information for conditions specified above scaled from a case of 1,128,000 lb/hr and an ITD of 40°F gives.

Table B-39
Encina Units 1, 2 and 3 Dry Cooling Retrofit Cost Estimates

Source/Basis	Equipment	Erection	Electrical	Duct Work	Indirect	Total	Cells
Vendor 1	$9,474,000	$4,054,000	$621,000	$62,000	$8,206,000	$22,417,000	21
Vendor 2	$9,929,000	$4,261,000	$496,000	$62,000	$8,518,000	$23,267,000	17
Vendor 3	$8,109,000	$3,972,000	$496,000	$62,000	$7,295,000	$19,933,000	17
Average	$9,171,000	$4,096,000	$538,000	$62,000	$8,007,000	$21,873,000	19
Scaled to 2007 $	$12,272,000	$4,878,000	$720,000	$83,000	$10,365,000	$28,318,000	
Including Indirects	$19,390,000	$7,707,000	$1,137,000	$131,000	$16,376,000	$44,742,000	

Table B-40
Encina Units 4 and 5 Dry Cooling Retrofit Cost Estimates

Source/Basis	Equipment	Erection	Electrical	Duct Work	Indirect	Total	Cells
Vendor 1	$27,069,000	$11,584,000	$1,773,000	$177,000	$23,447,000	$64,050,000	59
Vendor 2	$28,369,000	$12,175,000	$1,418,000	$177,000	$24,338,000	$66,478,000	47
Vendor 3	$23,168,000	$11,348,000	$1,418,000	$177,000	$20,842,000	$56,953,000	47
Average	$26,202,000	$11,702,000	$1,537,000	$177,000	$22,876,000	$62,493,000	53
Scaled to 2007 $	$35,064,000	$13,937,000	$2,057,000	$238,000	$29,613,000	$80,908,000	
Including Indirects	$55,401,000	$22,021,000	$3,250,000	$375,000	$46,789,000	$127,834,000	

Therefore, the total cost of a dry cooling retrofit for all five units at Encina would be almost $400 million or more than $425/kW. A capital expenditure of this magnitude is considered unreasonable for a facility where the average capacity factor has been less than 20% for the last two years. Furthermore, the siting of over 160 cells of air-cooled condenser at any reasonable distance from the turbine steam exhaust is not possible at this site. Therefore, dry cooling retrofit is not considered any further in this analysis.

Effect on Plant Performance

A retrofitted cooling system of either the wet or dry type would have a deleterious effect on the plant net heat rate. This arises from two effects:

1. Considering only the wet system, the power requirements will be higher than the current pumping power requirements for the once-through system. This power is used for the additional circulating pumps and for the cooling tower fans and represents power that must be generated but cannot be sold.
2. The plant will operate at a higher backpressure and therefore a higher heat rate with closed cycle cooling. This effect will be much more pronounced for a dry system than for a wet system.

The additional power requirements are estimated as follows:

Pumping power: The circulating water flow rate must be pumped through an additional head rise. This will be estimated at 40 feet to account for the lift out of the sump, the rise to the hot water distribution deck on the top of the tower and the head loss through the circulating water lines. A combined pump/motor efficiency of 75% is assumed. Each of these factors would be refined in a detailed analysis, but these are considered adequate to give a reasonable estimate of the effect of additional operating power on the plant. For the several units at Encina:

Table B-41
Encina Units: Retrofit Additional Pumping Power

Unit	Flow	Head	Eff	Power
	gpm	ft		kW
1	48,000	40	0.75	361.6
2	48,000	40	0.75	361.6
3	48,000	40	0.75	361.6
4	200,000	40	0.75	1506.5
5	208,000	40	0.75	1566.7

Fan power: Similarly cooling tower fan power can be roughly estimated. It is assumed for retrofits on older, lower capacity factor units, the tower would be sized to "low first cost" design since the number of operating hours is low and power penalties are less severe. This is consistent with the assumptions made in the retrofit capital cost estimates. The number of cells will be estimated as one cell per 10,000 gpm of circulating water flow, the fan horsepower at 200 HP and a motor efficiency of 90%. For the Encina units this results in:

Table B-42
Encina Units: Retrofit Fan Power

Unit	Flow	Cells	Eff	Power	Motor
	gpm	n		hp	kW
1	48,000	5	0.9	960	796
2	48,000	5	0.9	960	796
3	48,000	5	0.9	960	796
4	200,000	20	0.9	4,000	3,316
5	208,000	21	0.9	4,160	3,448

This represents a combined, full-load operating power requirement of approximately 13.4 MW or approximately 1.5% of the plant power rating of 923 MW. The actual annual cost will obviously depend on the capacity factor, the number of hours on-line, and whether some fans are turned off when operating at part load. Also, the cooling system was sized for full load at acceptable backpressures at so-called "1%" ambient conditions, it would be well oversized for nearly the entire year. Therefore, the effect of requiring additional operating power for the pumps and fans coupled with operation at higher heat rate would be an increase in the fuel burned rather than a reduction in plant output under most operating conditions. However, at full load a capacity reduction would be incurred .

In this context, it should be noted that some plants guarantee an available capacity and are paid for having this capacity available at some amount per MW. If the effect of the retrofit is to reduce the available capacity because of the increased operating power for pumps and fans and because of an increased heat rate, the capacity that could be guaranteed would be reduced with a corresponding reduction in the capacity payments. Heat rate penalty: As seen in the earlier plot of comparative backpressures, the condensing pressure with closed-cycle wet cooling will run typically 0.5 to 1.0 in Hga higher than it would with once-through ocean cooling and increases to about 2.5 in Hga on the hottest days. The effect is less at part load. However, information from comparable units suggest an increase of at least 0.25% for each 0.1 in Hga increase in backpressure above design at full load with higher percentage effects to be expected at intermediate load. The comparative plot shown earlier suggest that closed cycle cooling will result in increased backpressure throughout the year ranging from 0.5 to 1. in Hga with a corresponding heat rate penalty of 0.5 to 1.%. In the absence of other information, it is assumed to be applicable to the Encina units as well resulting in a heat rate penalty at full load of 0.5 to 1.% for the units at the plant.

A one percent operating penalty, combined with a 1.5% penalty associated with additional operating power requirements, sums to a 2.5% output reduction or a 25 MW shortfall at full load.

Maintenance Costs

Commonly used factors for maintenance (labor, materials, chemicals, etc.) for wet cooling systems range from 2. to 3. % of the system capital costs.

For wet systems, the important costs are for water treatment, biofouling control and keeping the basin clean. Using salt water and having salt drift around the plant would require rust control, extra painting, etc. Using the high end of typical factors, assume 3. to 3.5% of the capital cost of the tower. It is unclear how Encina would allocate these costs between operation and maintenance, but an estimate of 3% of the "average" capital costs for all units of $57 million could amount to approximately $1,700,000 per year.

Additional Cost Considerations

Although the S&W costs are pretty close to the Maulbetsch Consulting survey's "Average" difficulty estimate, neither of those estimates can account for any site-specific difficulties, which might be encountered at the Harbor site. Those items that could cause a retrofit at this site to be in a different, either "High" or "Easy" category include:

- Difficulty in locating the tower
- Unusual site preparation costs
- Significant interferences to the cost of installation of the circulating water lines
- The need for cooling tower plume abatement
- Stringent noise control
- The use of an alternate make-up water

Location of Tower/Unusual Site Preparation Costs/Interferences

A possible location, shown in the next two figures, for a cooling tower is in an area in the northeast corner of the site currently occupied by one in-service (Tank #2 in the middle) and two unused fuel storages tanks.

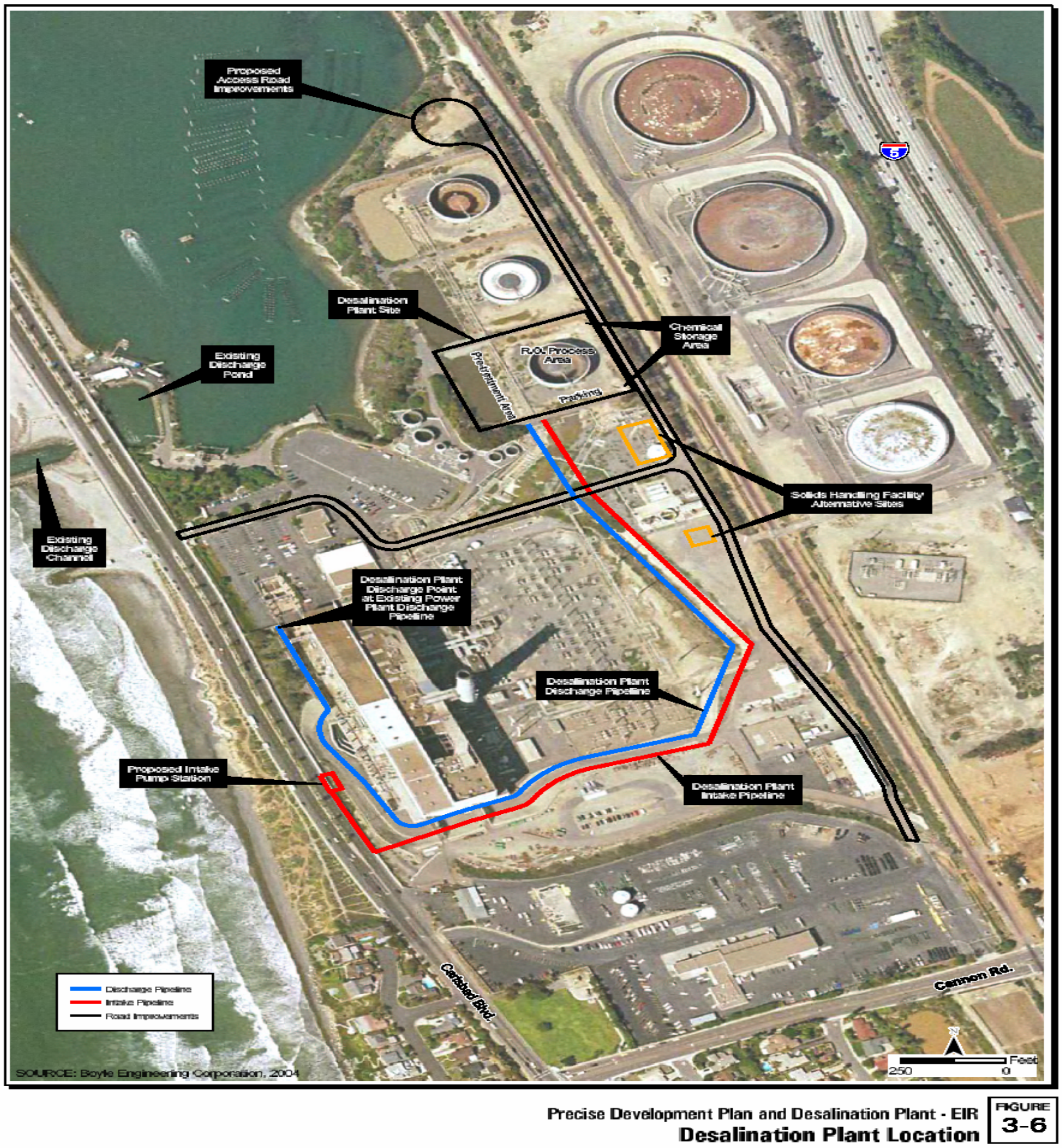


Figure B-32
Proposed Siting of Desalination Plant at Encina

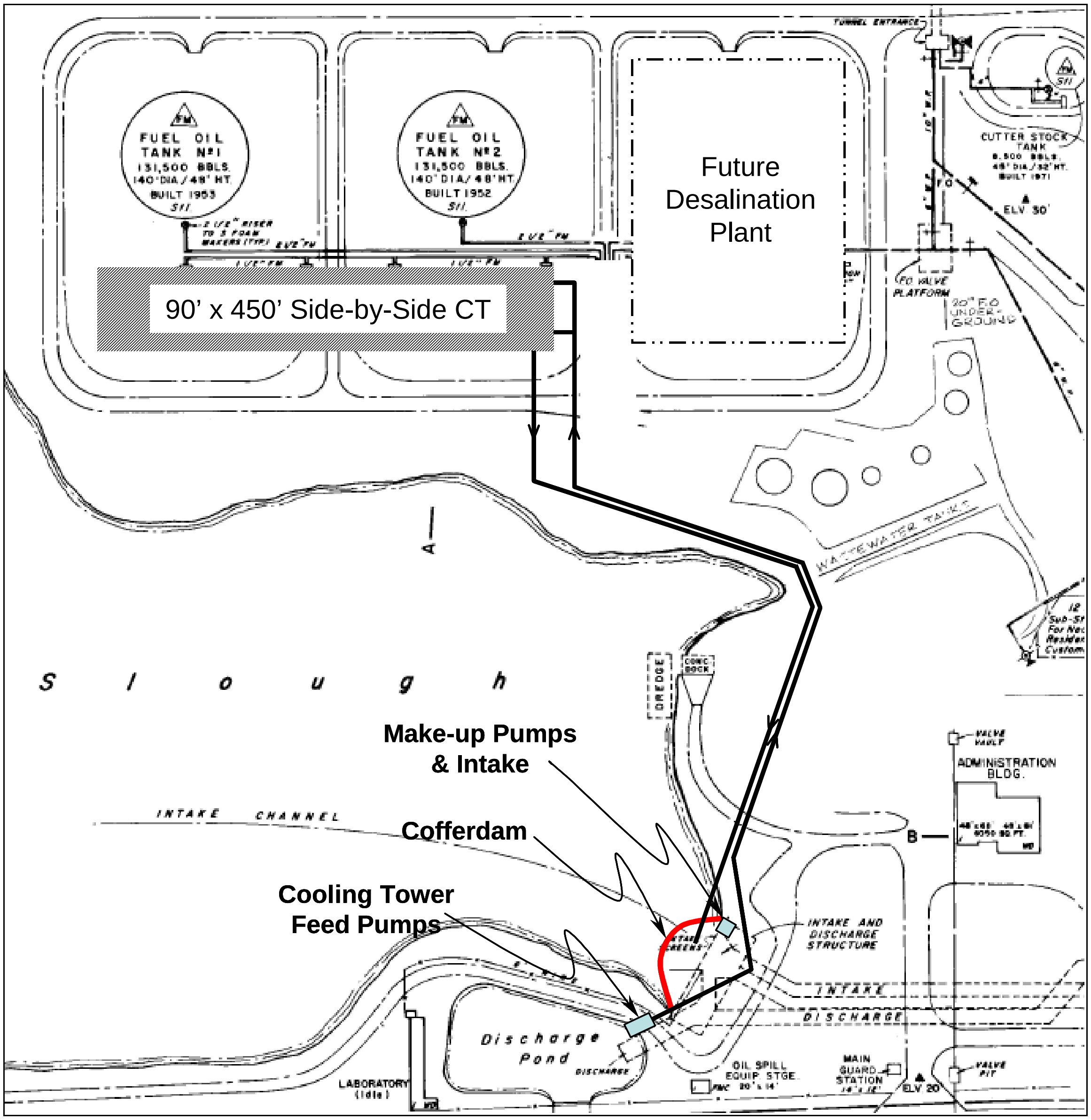


Figure B-33
Possible Location of Cooling Tower and Circulating Water Lines at Encina

The first figure shows the location of a proposed desalination plant at the site currently occupied by the southernmost tank (Tank 3). The tower, sized to handle the cooling for all five units at full load, would appear to fit in the area occupied by the two tanks to the north of the proposed desalination plant, assuming Tank 2 could be relocated or required fuel oil storage reconfigured to another onsite storage tank and still retain sufficient backup fuel oil to meet California Independent System Operator requirements. The circulating water lines would take water from the current cooling system discharge area and return it by gravity to the current intake area. It does not appear feasible to locate the cooling towers in the below grade containment areas around the fuel storage tanks and still maintain adequate secondary containment and keep the storage tank available for operation. Therefore, if this space would be utilized, significant grading would likely be required to build up the containment area for placement of cooling towers.

The concept of using a single tower for five units would reduce the difficulty of installing five separate sets of circulating water lines. It should be noted that this is not the basis on which the cost figures in either the S&W report or the Maulbetsch Consulting survey were developed. It is likely that some cost savings could be achieved with this approach but the primary reason for considering it was to determine whether combining the systems could ease the siting problem.

The location had possible drawbacks including

i. Unstable soil conditions requiring significant foundation work such as deep pilings to stabilize the towers.
ii. The need to demolish and remove existing tanks.
iii. Grading requirements after tank removal due to the below grade containment areas.
iv. Underground infrastructure, which would make the installation of underground circulating water lines difficult and costly.
v. Possible difficulty of tying into the existing circulating water system.
vi. Probable neighborhood objections to visible plumes, corrosive drift and noise.
vii. The need for PM10 offsets for expected drift from seawater towers.

No information is available on geology and soil conditions but sites this close to the coast are sometimes saturated zones requiring extensive pumping of groundwater during excavation and trenching and may be unstable requiring extraordinary piling or foundation preparation to support heavy structures.

The demolition and removal of the fuel tanks has apparently been considered feasible in the consideration of the siting of the desalination plant but it would add to the time and cost of the project. In addition, due to corrosion resistance measures, oil contaminated soil is present below each storage tank and would need to be remediated upon demolition and which would add additional cost to the retrofit.

Underground piping and other interferences, both in the vicinity of the fuel tanks and near the tie-in points near the plant can significantly increase the cost of the installation of the circulating water lines. No information is available to determine the extent of any possible interferences or to estimate their effect on cost.

Plume Abatement

Based on the view in the aerial photo of the neighboring area, it appears that a visible plume could be a serious issue at this site. The figure below shows a broader view of the surrounding areas and displays some distance to critical areas. The plume could, under some conditions partially obscure vision on I-5 about 0.2 miles to the east. In addition, it would be visible from the beach (~ 0.2 miles) and two nearby residential areas (~ 0.3 and 0.5 miles). While the occasional view of the plume from residential areas and the beach might not be a critical issue, the safety issues related to the highway will probably be. It is, therefore, reasonable to assume that a plume abatement tower would be required.

Figure B-34

Neighboring Critical Areas

Plume abatement towers have an air-cooled section on top of the wet tower. The hot water is pumped to the top of the tower, passes down through the dry section and then discharged onto the hot water distribution deck of the wet section. The air passing across the finned tubes of the dry section mixes with the wet plume coming off the wet section and keeps it from becoming saturated and condensing in the cold atmosphere. However, the need for a plume abatement tower design raises the following issues.

1. The need for a plume abatement tower would increase both the capital cost of the tower itself by a factor of perhaps 2. to 2.5 and, therefore, increase the total project cost by perhaps 30%.

2. The additional pump and fan power would increase due to the increased tower height and the higher airflow required for the dry section. Quantitative information is not available to estimate the power requirements precisely but it is reasonable to expect a 50% increase in pumping power (60 ft. vs. 40 ft.) and perhaps a 35% increase in fan power.

3. The tower height would increase by 20 to 30 feet and would then exceed the local height limits of 45 feet as specified by plant staff. It is not known whether this would

completely rule out the use of a plume-abated tower at the site or would still be allowable but require extensive screening by berming or landscaping or both.

4. If a plume abatement tower were required, a back-to-back arrangement would not be possible and the configuration shown in Figure B-33 (?) would need to be changed. It appears that it would be possible to arrange two in-line, but separate, towers in the area currently occupied by Tank 1. However, this would add to the complexity of installing the recirculating water lines and further increase the degree of difficulty of the retrofit.

Aesthetics

In addition to any issues with a visual plume, the simple appearance of a cooling tower is sometimes considered an aesthetic affront. In this instance, even though the towers would be readily visible to neighbors, considering the number and size bulk of the plant buildings already present, it is possible that conformity with coastal zone and city requirements could be attained, but not likely without required visual mitigation.

Noise Control

Two features of the site suggest that noise would be serious concern similar to that for visible plumes. First, the proximity of a residential area to the South; second, the presence of the lagoon to the North. The edge of the lagoon is a public access area with a substantial wildlife population. The lagoon is used for fishing and is currently outfitted with noise receptors. Therefore, the need for some degree of noise abatement should be assumed.

Noise from wet cooling towers comes both from the fans and from the water cascading through the fill. Fan design or the reduction in air velocity, which sometime requires the use of bigger, or more, cells, can diminish fan noise. The water noise is more difficult to reduce and usually requires the construction of sound barriers around the cooling tower. The aerial photo of the plant and the neighboring area makes it appear that cooling tower noise should not be a serious constraint, give the pre-existing noise that presumably comes from I-5. In case that it is, the capital cost of the tower itself cost might increase from 20 to 40%.

Alternate Sources of Make-Up Water

The use of seawater make-up can introduce intractable problems regarding drift and related maintenance considerations. (See later discussion of drift and PM10.) An alternative can be to purchase reclaimed water from nearby municipal water treatment facilities. The figure below shows the location of the Encina Wastewater Authority, which is the nearest source of treated municipal water. It is located approximately 1-¾ miles south of the plant.

The facility treats 36 million gallons per day, but most of it treated only to secondary standards (tertiary treatment is required for cooling tower use). Further, all of the tertiary treated capacity is already prescribed by the City of Carlsbad to other users in the city. The aerial view below indicates the neighborhood through which supply and return lines would have to be run. While there is no specific information available by which to estimate the cost, similar projects in far less congested areas have incurred costs of over

$1 million per mile and costs of several ties that would not seem unreasonable. Further, purchase of the reclaimed water would add substantial annual operating cost.

Figure B-35

Encina Wastewater Authority Location

Shutdown Period

There is often concern over the period of lost plant availability during the retrofit construction period. In this instance, it appears that the major part of the construction could be done while the plant is on-line, with shutdown required only for the final tie-in of the circulating water lines to the existing water circuit. There is no information available to estimate how long this might be. More detailed analyses of similar plants indicate that downtimes of one to two months might be expected. It may be possible to tie in the several units sequentially or at least in groups so that there would always be at least one unit operating.

The operating profiles shown earlier for 2005 indicate some periods of little operation and the unit capacity factors in 2006 were low. Therefore, it appears, although it cannot be guaranteed, that the tie-ins could be accomplished with no serious downtime.

However, current commercial arrangements at the facility are not tied to actual operations, but are directly linked to having the plant capacity always available, except during allowed outages. The expected outages for this retrofit would be unusually long and would reduce capacity revenue at the plant accordingly.

Other Environmental Issues

Retrofit to a closed-cycle cooling system introduces some environmental issues that a once-through cooling system does not. These are increased air emissions from the stack and drift from the cooling tower.

Stack Emissions

In an earlier section it was noted that a closed-cycle retrofit increase the unit net output because of heat rate penalties and the use of increased operating power. In this instance these together were estimated at 2.5%. Therefore, the delivery of the same amount of electric power to the grid will require the burning of additional fuel at some location to make up that lost at Encina. Furthermore, in the discussion of this issue in Chapter 7, it was pointed out that the effect of making up this shortfall was highly variable depending on how and where the replacement per was generated. Therefore, no attempt is made to assess the effect in quantitative terms beyond pointing out that reliable estimates of the shortfall to be expected from full load operation can be made. However, generally speaking, making up the lost 25 MWs of peak capacity would equate to building a small peaking power plant at an approximate cost of $1000/kW or about $25 million and the resultant air emissions from such a plant.

Drift

It is assumed that any cooling tower would be equipped with state-of-the-art drift eliminators rated at about 0.0005% of circulating water flow. The following table estimates the amount of drift to be expected from such designs. In addition, as discussed earlier, Federal EPA and State regulations characterize all solids carried off in cooling tower drift as PM10. The cost of offsetting this amount, should it be necessary will vary considerably from site to site as will the severity of the regulatory constraints. These costs were not included in this estimate, but would likely be substantial.

Table-B-43
Encina Drift Estimates

Unit	Flow gpm	Drift[1] gpm	Drift lb/hr	PM10 lb/hr	PM10 tons/year[2]	Cap. Factor %	PM10 tons/year[3]
1	**48,000**	0.24	120	6.00	26.3	**24.7**	**6.5**
2	**48,000**	0.24	120	6.00	26.3	**24.7**	**6.5**
3	**48,000**	0.24	120	6.00	26.3	**24.7**	**6.5**
4	**200,000**	1.00	500	24.99	109.5	**25.7**	**28.1**
5	**208,000**	1.04	520	25.99	113.8	**26.7**	**30.4**

1. At drift eliminator efficiency of 0.0005%
2. Assumes full load all year
3. At 2006 capacity factor

It should be noted from the aerial view in the first figure that the grey, nearly rectangular area just east of I-5 from the plant site is a prime strawberry field. Serious objections to any possibility of saline drift on the field are to be expected and required mitigation is likely.

General Conclusion

On balance, it is concluded that the nature of the likely problems and additional costs to be encountered at Encina would put the retrofit at this site in a “difficult” category. Based on the results from the Maulbetsch Consulting survey presented above, this would put the project cost in the range of $220 million.

B.5 Haynes Generating Station (Los Angeles Department of Water and Power)

Location

6801 E. 2nd Street
Long Beach, CA 90803-4324
33° 45' 46.81" N; 118° 05' 44.63" W
Contact: Katherine Rubin, 213-367-0436

Figure B-36
Haynes Generating Station: Boundaries and Neighborhood

Figure B-37
Haynes Generating Station: Site View

Plant/Site Information

Unit 1: 222 MW
Unit 2: 222 MW
Unit 5: 322 MW
Unit 6: 322 MW
Unit 8: 235 MW

Table B-44
Haynes Cooling System Operating Conditions

Unit	MW	Cooling Water flow		Steam flow	Heat duty	Tin	Tex	Range	Tcond	TTD	Backpressure
		gpm	cfs	lb/hr	Btu/hr	F	F	F	F	F	in Hga
1	222	88,900	198	9.050E+05	8.600E+08	62.0	81.4	19.4	91.7	10.3	1.50
2	222	88,900	198	9.050E+05	8.600E+08	62.0	81.4	19.4	91.7	10.3	1.50
5	322	136,000	303	1.200E+06	1.180E+09	62.0	79.4	17.4	91.7	12.3	1.50
6	322	136,000	303	1.200E+06	1.180E+09	62.0	79.4	17.4	91.7	12.3	1.50
8	235	146,000	325	1.128E+06	1.104E+09	63.0	78.5	15.5	93.0	14.5	1.56

Table B-45
Haynes Plant Capacity Factor (for Total Plant Only)

Unit	2001	2002	2003	2004	2005	2006	Average
all	23.6%	16.5%	17.7%	14.5%	25.9%	24.7%	20.5%

Table B-46
Haynes Site Meteorological Data

Temperature	Max.	Average	Min.
Intake water[1]	68	63	57
Atmos. wet bulb[2]	~73	~58	32
Atmos. dry bulb[2]	102	~65	37

[1]Data for nearby ocean temperatures ranges from 57°F to 68°F. It seems likely that given the location of the Haynes inlet that the water will be significantly warmer in summer months. Estimates were made adding 3°F. See discussion of backpressures in next section.

[2] Estimated from tables of "Normals, Means and Extremes—Long Beach, CA", NOAA, 1992.

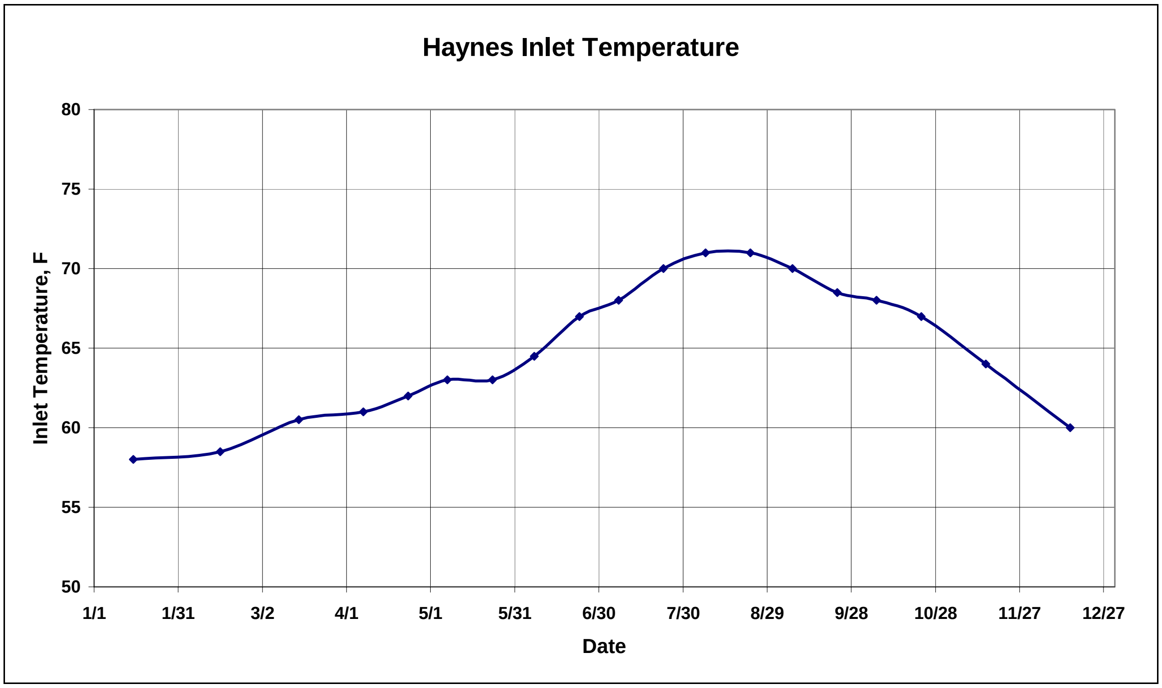


Figure B-38
Haynes Inlet Temperature

Plant Operating Data

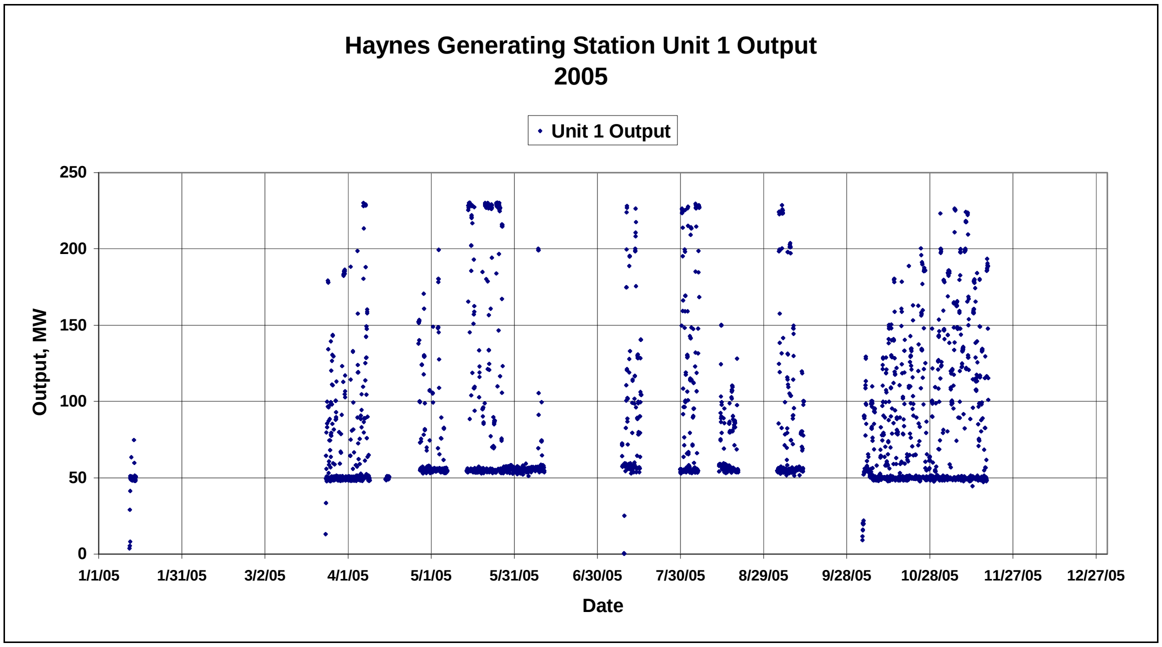


Figure B-39
Haynes Unit 1 Output in 2005

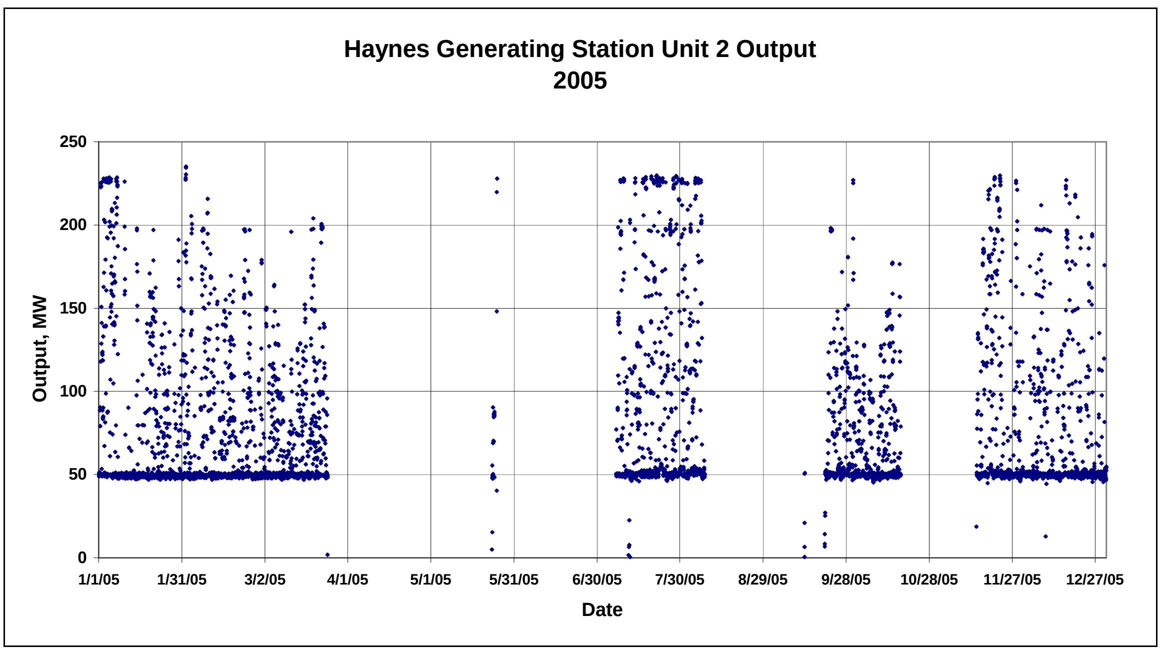


Figure B-40
Haynes Unit 2 Output in 2005

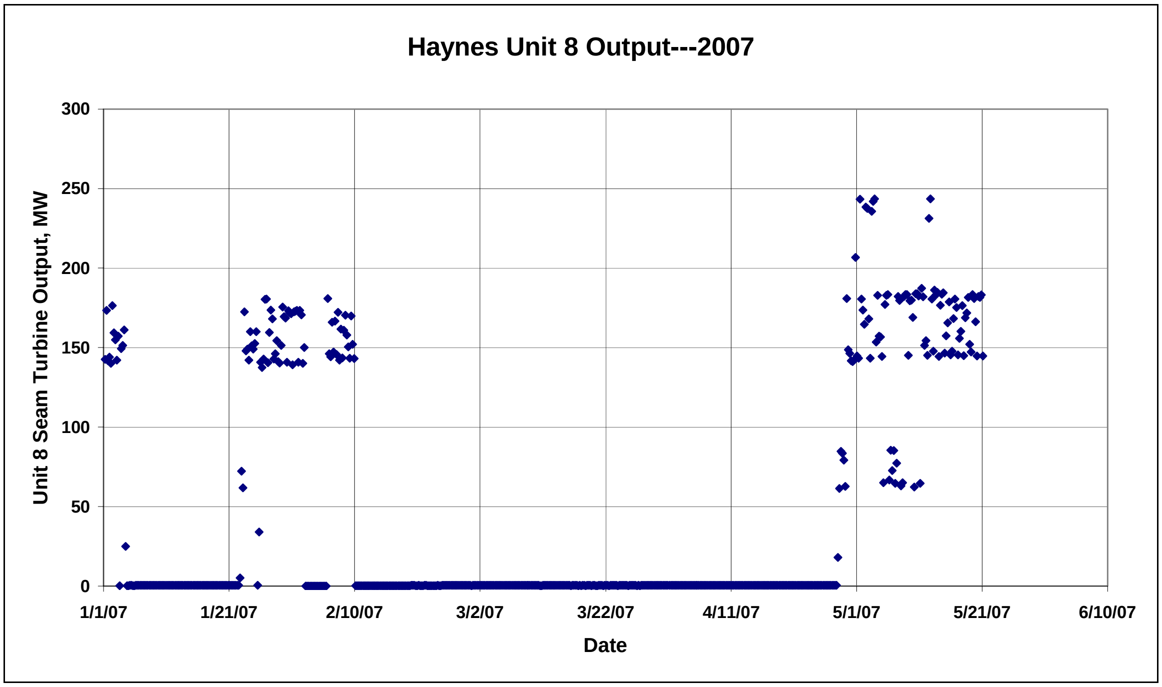


Figure B-41
Haynes Unit 8 Output in 2007

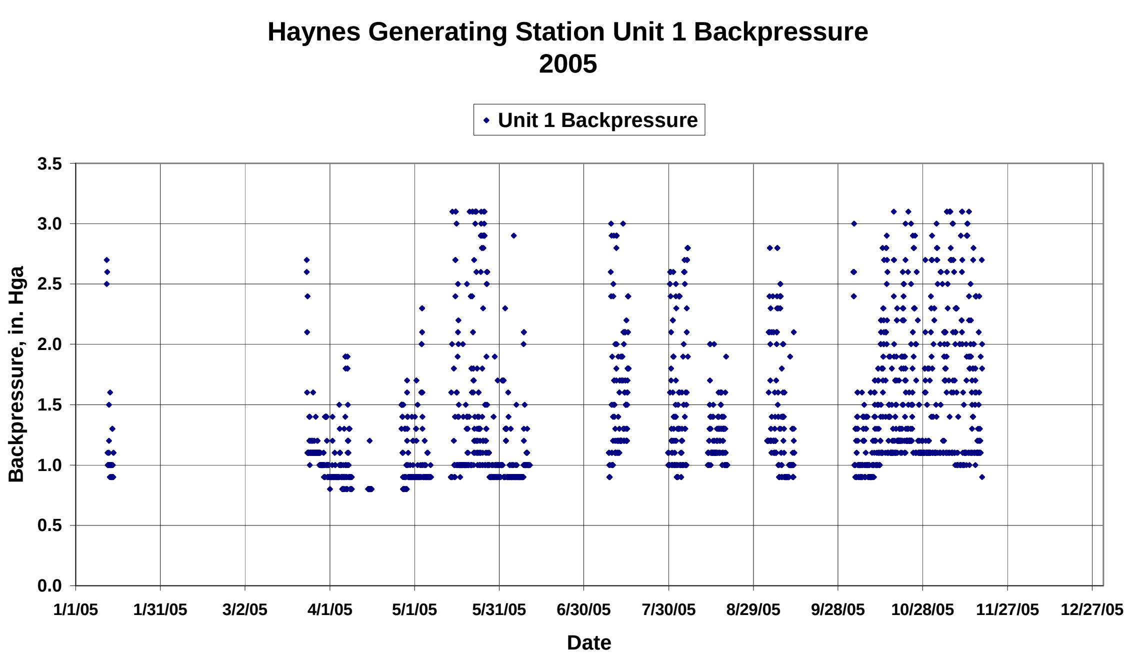


Figure B-42
Haynes Unit 1 Backpressure in 2005

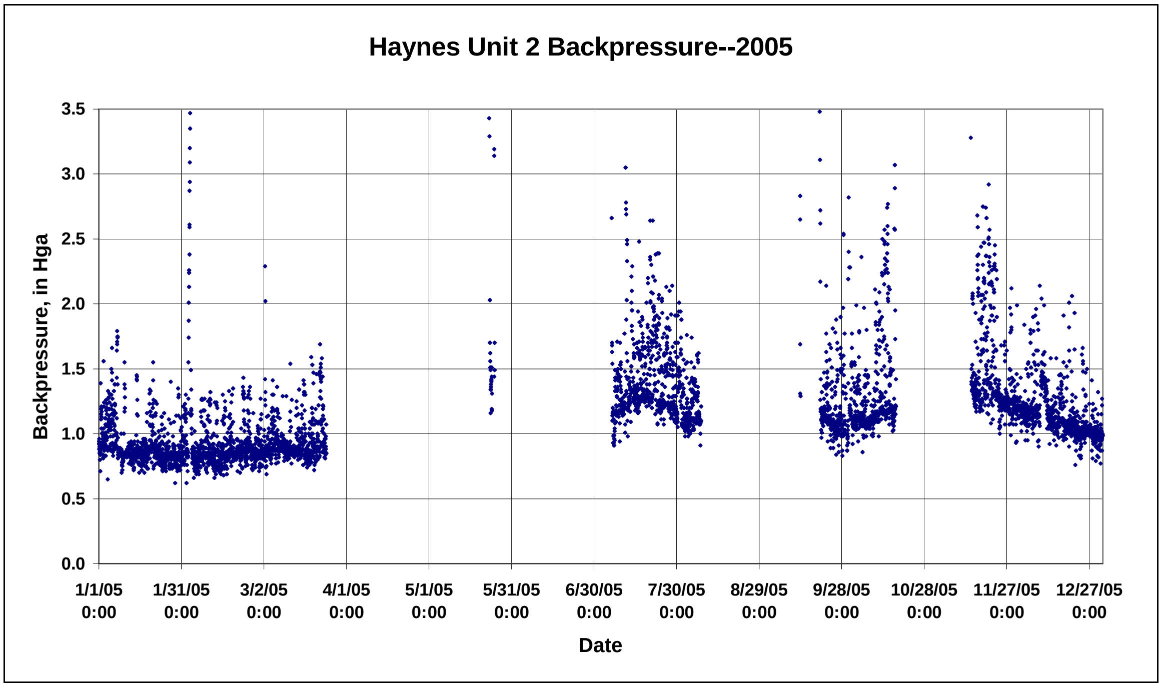


Figure B-43
Haynes Unit 2 Backpressure in 2005

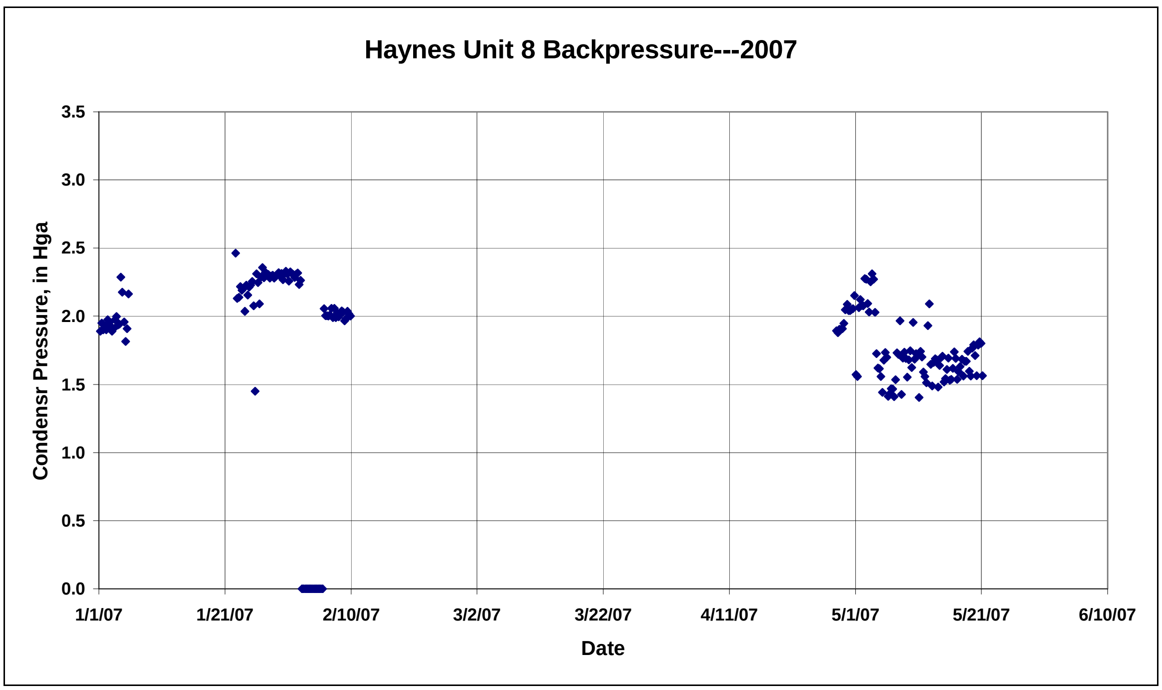


Figure B-44
Haynes Unit 8 Backpressure in 2007

"Similar operating profiles and backpressure plots could be produced for Units 5 and 6 which would show similar behavior but data were not available to construct them. The results for Unit 2 will be used as a representative example of the several units at the plant."

The following chart, using Unit 2 as an example, compares the estimated with the reported backpressure for operation during 2005.

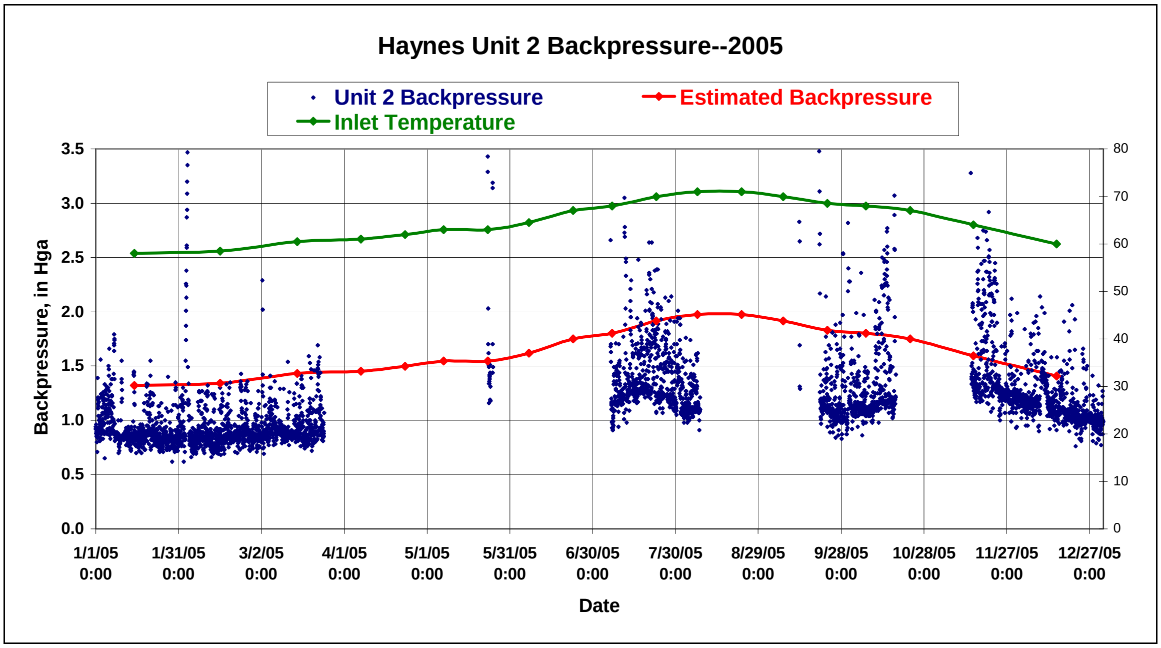


Figure B-45
Comparison With Estimated Backpressure (for Full Load)

Cooling Tower Assumptions/Design

Wet cooling system design specs for all units

- Tower type: mechanical draft, counterflow, FRP construction
- Make-up water source: Sea water; 35,000 ppm salinity
- Operating cycles of concentration: n = 1.5

Table B-47
Cooling Tower Water Balance Specifications

Unit	Evaporation gpm	Make-up gpm	Blowdown gpm
1	2,200	6,600	4,400
2	2,200	6,600	4,400
5	3,200	9,600	6,400
6	3,200	9,600	6,400
8	2,400	7,200	4,800

Tower design conditions are for all circulating water flows and condenser specifications unchanged, an assumed tower approach of 10°F and a peak wet bulb temperature of 70°F.

Table B-48
Cooling Tower Design Conditions for Full Load on Hot Day

Unit	Ambient Wet Bulb	Range	Approach	TTD	Tcond	Backpressure
	F	F	F	F	F	in Hga
1	70	19.4	10	10.3	109.7	~ 2.5
2	70	19.4	10	10.3	109.7	~ 2.5
5	70	17.4	10	12.3	109.7	~ 2.5
6	70	17.4	10	12.3	109.7	~ 2.5
8	70	15.5	10	14.5	110	~ 2.5

Therefore, on the hottest day at full load, all units would operate at a backpressure of approximately 2.5 in Hga. Over the course of the year when the ambient wet bulb temperature would be lower. The backpressure would vary as indicated in the following figure. A comparison is given to the backpressure estimated with once-through cooling and indicates that the backpressure would normally be elevated by 0.5 to 1. in Hga.

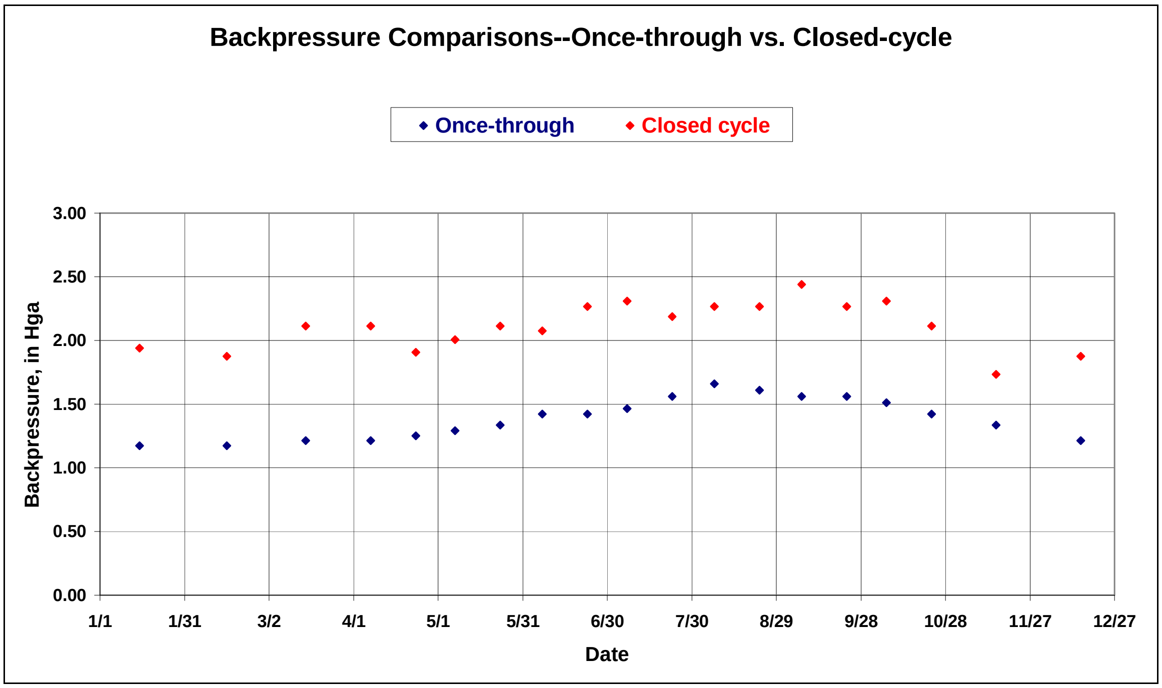


Figure B-46
Backpressure Comparisons

Wet Retrofit Costs

Table B-49
S&W Cost Estimates

S&W Costs---escalated to 2007; x 1.07 for seawater					
Unit	**Labor**	**Material**	**Equipment**	**Indirect**	**Total**
1	**$6,239,000**	**$3,637,000**	**$6,186,000**	**$9,316,000**	**$25,378,000**
2	**$6,239,000**	**$3,637,000**	**$6,186,000**	**$9,316,000**	**$25,378,000**
5	**$9,539,000**	**$5,556,000**	**$9,451,000**	**$14,236,000**	**$38,781,000**
6	**$9,539,000**	**$5,556,000**	**$9,451,000**	**$14,236,000**	**$38,781,000**
8 (scaled)	**$10,245,000**	**$6,385,000**	**$10,860,000**	**$15,944,000**	**$43,434,000**
Plant Total	**$41,801,000**	**$24,770,000**	**$42,133,000**	**$63,049,000**	**$171,753,000**

Table B-50
Maulbetsch Consulting Survey Estimates

JSM Survey; escalated to 2007 $; x 1.07 for salinity			
Unit	**Easy**	**Average**	**Difficult**
1	**$14,628,000**	**$24,381,000**	**$37,679,000**
2	**$14,628,000**	**$24,381,000**	**$37,679,000**
5	**$22,386,000**	**$37,310,000**	**$57,660,000**
6	**$22,386,000**	**$37,310,000**	**$57,660,000**
8	**$24,090,000**	**$40,150,000**	**$62,050,000**
Plant Total	**$98,118,000**	**$163,531,000**	**$252,729,000**

Dry Cooling

Similar cost estimates can be made for a dry cooling retrofit. The basic assumption is that for plants with low capacity factors, they must be available to produce close to full load on the hottest days of the year when the system load is at its peak. Therefore, using Unit 8 as an example

- Direct dry cooling: forced, mechanical-draft air-cooled condenser
- Steam flow: ~ 1,128,000 lb/hr (Unit 8 full load)
- Design dry bulb: 100°F (mid-way between 0.4% dry bulb and median of extreme highs)
- Design turbine exhaust pressure: 4.5 in Hga (based on assumption that turbines of this age and design trip at 5 in Hga and that the plant would not wish to reduce output on the hottest days)
- Corresponding condensing temperature: 130°F

Therefore, ACC design ITD ($T_{condensing}$ - $T_{design\ ambient}$) = 130°F – 100°F = **30°F**

Dry Cooling Retrofit Costs

AC costs can be roughly estimated from EPRI Report No. 1005358; “Comparison of Alternate Cooling Technologies for U.S. Power Plants”, August, 2004.

Vendor information for a design of:

Steam flow: 1,128,000 lb/hr (scaled from example case of 1,080,000 lb/hr)
ITD: 30°F

Price: 2002 $

Table B-51
Dry Cooling Retrofit Cost Estimates

Source/Basis	Equipment	Erection	Electrical	Duct Work	Indirect	Total	Cells
Vendor 1	$22,900,000	$9,800,000	$1,500,000	$150,000	$19,836,000	$54,186,000	50
Vendor 2	$24,000,000	$10,300,000	$1,200,000	$150,000	$20,590,000	$56,240,000	40
Vendor 3	$19,600,000	$9,600,000	$1,200,000	$150,000	$17,632,000	$48,182,000	40
Average	$22,167,000	$9,900,000	$1,300,000	$150,000	$19,353,000	$52,869,000	45
Scaled to 2007 $	$29,664,000	$11,791,000	$1,740,000	$201,000	$25,053,000	$68,448,000	
Including Indirects	$46,869,120	$18,629,780	$2,749,200	$317,580	$39,583,740	$108,147,840	

Comparison with Individual Design

Cost estimates for a range of cooling system retrofit options were performed by Sargent & Lundy for LADWP. For the wet cooling system the capital costs developed in that study superficially show reasonable agreement with the range of costs developed in this study. Sargent & Lundy capital cost for "wet cooling" in 2004 $ was reported to be $111 million. When scaled to 2007$ at 6% per year, the cost is $136 million compared to $159 million for the "average" difficulty case from the survey and $165 million from the S&W estimates. There is insufficient detail in the information available to this study for the Sargent & Lundy methodology and assumptions to analyze the differences.

The agreement for the dry cooling cases is poorer. The S&L capital costs are given a $243 million ($2004) or ~$290 million ($2007). The example value for Unit 8 alone given above is $108 million. If scaled to the total plant steam flow rate the estimated capital cost would exceed $400 million. Again, there is insufficient information to understand the differences. However, the basic conclusion is similar.

The major apparent difficulties for dry cooling were the lack of adequate space for the ACC and the distance of candidate locations from the turbine halls. ACC's are normally sited quite close to the turbine exhaust to minimize the length (and therefore the cost and the steam side pressure drop) of the steam duct. No obvious way to address this problem could be seen. This is apparently consistent with the assessment of Sargent and Lundy. Therefore, except for this quick review of the S&L report for comparison purposes, dry cooling retrofit was not considered further at Haynes.

Effect on Plant Performance

A retrofitted cooling system of either the wet or dry type would have a deleterious effect on the plant net heat rate. This arises from two effects:

1. Considering only the wet system, the power requirements will be higher than the current pumping power requirements for the once-through system. This power is used for the additional circulating pumps and for the cooling tower fans and represents power that must be generated but cannot be sold.
2. The plant will operate at a higher backpressure and therefore a higher heat rate with closed cycle cooling. This effect will be much more pronounced for a dry system than for a wet system.

The additional power requirements are estimated as follows:

Pumping power: The circulating water flow rate must be pumped through an additional head rise. This will be estimated at 40 feet to account for the lift out of the sump, the rise to the hot water distribution deck on the top of the tower and the head loss through the circulating water lines. A combined pump/motor efficiency of 75% is assumed. Each of these factors would be refined in a detailed analysis, but these are considered adequate to give a reasonable estimate of the effect of additional operating power on the plant. For the several units at Haynes:

Table B-52
Haynes Units: Retrofit Additional Pumping Power

Unit	Flow	Head	Eff	Power	Motor
	gpm	ft		kW	MW
1	88,900	40	0.75	669.6	0.89
2	88,900	40	0.75	669.6	0.89
5	136,000	40	0.75	1024.4	1.37
6	136,000	40	0.75	1024.4	1.37
8	146,000	40	0.75	1099.7	1.47

Fan power: Similarly cooling tower fan power can be roughly estimated. It is assumed for retrofits on older, lower capacity factor units, the tower would be sized to "low first cost" design since the number of operating hours is low and power penalties are less severe. This is consistent with the assumptions made in the retrofit capital cost estimates. The number of cells will be estimated as one cell per 10,000 gpm of circulating water flow, the fan horsepower at 200 HP and a motor efficiency of 90%. For the Haynes units this results in:

Table B-53
Haynes Units: Retrofit Fan Power

Unit	Flow	Cells	Eff	Power	Motor
	gpm	n		hp	kW
1	88,900	9	0.9	1778	1474
2	88,900	9	0.9	1778	1474
5	136,000	14	0.9	2720	2255
6	136,000	14	0.9	2720	2255
8	146,000	15	0.9	2920	2420

This represents a combined, full-load operating power requirement of approximately 20. MW or approximately 1.2% of the plant power rating of 1,675 MW. The actual annual cost will obviously depend on the capacity factor, the number of hours on-line, and whether some fans are turned off when operating at part load. Also, the cooling system was sized for full load at acceptable backpressures at so-called "1%" ambient conditions, it would be well oversized for nearly the entire year. Therefore, the effect of requiring additional operating power for the pumps and fans coupled with operation at higher heat rate would be an increase in the fuel burned rather than a reduction in plant output.

Heat rate penalty: As seen in the earlier plot of comparative backpressure, the condensing pressure with closed-cycle wet cooling will run typically 0.5 to 1.0 in Hga higher than it would with once-through ocean cooling and increases to about 2.5 in Hga on the hottest days. The effect is less at part load. Information provided by plant staff indicated a heat rate penalty for Unit 8 of approximately 0.25% for each increase in backpressure of 0.1 in Hga above design. The comparative plot shown earlier suggests that closed cycle cooling will result in increased backpressure throughout the year ranging from 0.5 to 1. in Hga with a corresponding heat rate penalty of 0.5 to 1.%. This information was specifically for Unit 8, the steam portion of a combined cycle unit, but, in the absence of other information, it is assumed to be applicable to the other units as well as resulting in a heat rate penalty at full load of 0.5 to 1.% for the steam units at the plant. It is noted that this penalty is significantly less than what was estimated for Harbor of 1000 Btu/kWh for a increase in backpressure from 1.5 to 2.5 in Hga.

Capacity Limits

The increased back pressure will likely results in an output restriction at the hottest day. The magnitude of the shortfall will depend on the operating philosophy. If the firing rate is held constant, a 1% heat rate penalty would correspond to roughly a 1% reduction in output. For the combined cycle unit, this could presumably be compensated for with duct firing, but the heat rate penalty and hence the fuel cost, would increase even further.

Even for the steam units, it would appear to be a minor effect on output. If, however, it were to be decided that operation at a backpressure of 2.5 in Hga constituted an unacceptable maintenance risk to the turbine, then the firing rate would need to be reduced to hold whatever backpressure was consider acceptable. Information to estimate what the shortfall would be in that case is not available but presumably could be estimated by plant staff based on the information given above.

Maintenance Costs

Commonly used factors for maintenance (labor, materials, chemicals, etc.) for wet cooling systems range from 2. to 3. % of the system capital costs.

For wet systems, the important costs are for water treatment, biofouling control and keeping the basin clean. Using salt water and having salt drift around the plant would require rust control, extra painting, etc. Using the high end of typical factors, assume 3. to 3.5% of the capital cost of the tower. It is unclear how LADWP would allocate these costs between operation and maintenance, but an estimate of 3% of the "average" capital costs for all units of $160 million could amount to approximately $5,000,000 per year.

Additional Cost Considerations

Although the S&W costs are pretty close to the Maulbetsch Consulting survey's "Average" difficulty estimate, neither of those estimates can account for any site-specific difficulties which might be encountered at the Haynes site. Those items that could cause a retrofit at this site to be in a different, either "High" or "Easy" category include:

- Difficulty in locating the tower
- Unusual site preparation costs
- Significant interferences to the cost of installation of the circulating water lines
- The need for cooling tower plume abatement
- Stringent noise control
- The use of an alternate make-up water

Location of Tower/Unusual Site Preparation Costs/Interferences

Several alternate locations for the towers were considered. A base assumption was that the switch gear west of the power blocks would not be moved. Locations included

i. For Units 1 and 2: at the location of the present administration building and neighboring parking lot.
ii. For Units 5, 6 and 8: at the location of fuel tanks G, H and J north of the recently cleared area which is reserved for a proposed re-powering project.
iii. For all: open space east of the channel near the eastern boundary of the plant near the Senior citizens housing area.

All locations had serious drawbacks including

i. The need to demolish, relocate and rebuild existing structures for some locations.
ii. Unstable soil conditions requiring significant foundation work such as deep pilings to stabilize the towers.
iii. Drift deposition from salt water towers.
iv. Underground infrastructure which would make the installation of underground circulating water lines difficult and costly.
v. Remoteness of current intake bays (especially for Units 5, 6 and 8) from towers north
of the plant and difficulty in tying into the existing circulating water system.
vi. Probable neighborhood objections to visible plumes, corrosive drift and noise.
vii. The need for PM10 offsets for expected drift from seawater towers.

Plume Abatement

Based on the view in the aerial photo of the neighboring area, it appears that a visible plume could be a serious issue at this site primarily from an aesthetic viewpoint. It is reasonable to assume that a plume abatement tower would be required. Plume abatement towers have an air-cooled section on top of the wet tower. The hot water is pumped to the top of the tower, passes down through the dry section and then discharged onto the hot water distribution deck of the wet section. The air passing across the finned tubes of the dry section mixes with the wet plume coming off the wet section and keeps it from becoming saturated and condensing in the cold atmosphere. The need for a plume abatement tower would increase both the capital cost of the tower itself by a factor of perhaps 2. to 2.5 and the additional pumping power by an additional 30 to 50% due to the greater height to which the hot water must be pumped.

Aesthetics

In addition to any issues with a visual plume, the simple appearance of a cooling tower is sometimes considered an aesthetic affront. In this instance, even though the towers would be visible to neighbors, considering the number and size bulk of the plant buildings already present, it does not appear that this would present a major problem.

Noise Control

Noise from wet cooling towers comes both from the fans and from the water cascading through the fill. Fan noise can be diminished by fan design or the reduction in air velocity which sometime requires the use of bigger, or more, cells. The water noise is more difficult to reduce and usually requires the construction of sound barriers around the cooling tower. Since Haynes has been required in the past to install noise mitigation for turbines on the site, it is expected that some degree of noise mitigation will be required for a cooling tower. In case that it is, the capital cost of the tower itself cost might increase from 20 to 40%.

Alternate Sources of Make-Up Water

The use of seawater make-up can introduce intractable problems regarding drift and related maintenance considerations. (See later discussion of drift and PM10.) An alternative can be to purchase reclaimed water from nearby municipal water treatment facilities.

In this instance, however, possibility of using reclaimed water for wet cooling tower makeup was considered and rejected due to the distance of sources from the plant, the expected very high cost of installing delivery and return pipelines to the remote sources and the expected extended time required to obtain permits even if the approach were deemed feasible.

Shutdown Period

There is often concern over the period of post plant availability during the retrofit construction period. In this instance, it appears that the major part of the construction could be done while the plant is on-line, with shutdown required only for the final tie-in of the circulating water lines to the existing water circuit. There is no information available to estimate how long this might be. However, the operating profiles shown earlier for 2005 (2007 for Unit 8) indicate periods of little or no operation. Therefore, it appears that the tie-in could be accomplished with no serious downtime.

Other Environmental Issues

Retrofit to a closed-cycle cooling system introduces some environmental issues which a once-through cooling system does not. These are increased air emissions from the stack and drift from the cooling tower.

Stack Emissions

In an earlier section it was noted that a closed-cycle retrofit increase the unit net output because of heat rate penalties and the use of increased operating power. In this instance these together were estimated at from 1 to 2%. Therefore, the delivery of the same amount of electric power to the grid will require the burning of additional fuel at some location to make up that lost at Haynes. Based on the unit heat rate information provided, this does not appear to be major effect in this case. Furthermore, in the discussion of this issue in Chapter 7, it was pointed out that the effect of making up this shortfall was highly variable depending on how and where the replacement power was generated. Therefore, no attempt is made to asses the effect in quantitative terms beyond pointing out that reliable estimates of the shortfall to be expected from full load operation can be made.

Drift

It is assumed that any cooling tower would be equipped with state-of-the-art drift eliminators rated at about 0.0005% of circulating water flow. The following table estimates the amount of drift to be expected from such designs. In addition, as discussed earlier, Federal EPA and State regulations characterize all solids carried off in cooling tower drift as PM10. The cost of offsetting this amount, should it be necessary will vary considerably from site to site as will the severity of the regulatory constraints.

Table B-54
Haynes Drift Estimates

	Flow	Drift[1]	Drift	PM10	PM10	Cap. Factor	PM10
Unit	gpm	gpm	lb/hr	lb/hr	tons/year[2]	%	tons/year[3]
1	**88,900**	0.44	222	11.11	48.7	**24.7**	**12.0**
2	**88,900**	0.44	222	11.11	48.7	**24.7**	**12.0**
5	**136,000**	0.68	340	16.99	74.4	**24.7**	**18.4**
6	**136,000**	0.68	340	16.99	74.4	**24.7**	**18.4**
8	**146,000**	0.73	365	18.24	79.9	**24.7**	**19.7**

1. At drift eliminator efficiency of 0.0005%
2. Assumes full load all year
3. At 2006 capacity factor

General Conclusion

On balance, it is concluded that the nature of the likely problems and additional costs to be encountered at Haynes would put the retrofit at this site in a “difficult” category. Based on the results from the Maulbetsch Consulting survey presented above, this would put the project cost in the range of $250 million.

B.6 Huntington Beach Generating Station (AES Southland Corporation)

Location

Huntington Beach, CA 92648
33° 55’ 06.17” N; 118° 25’ 33.90” W
Contact: Steve Maghy, 562-493-7384

Figure B-47
Huntington Beach Generating Station: Boundaries and Neighborhood

Figure B-48
Huntington Beach Generating Station: Site View

Plant/Site Information

Unit 1: 215 MW
Unit 2: 215 MW
Unit 3: 225 MW
Unit 4: 225 MW

Table B-55
Huntington Beach Cooling System Operating Conditions

Unit	MW	Cooling Water flow		Steam flow	Heat duty	Tin	Tex	Range	Tcond	TTD	Backpressure
		gpm	cfs	lb/hr	Btu/hr	F	F	F	F	F	in Hga
1	215	84,000	187	9.988E+05	9.488E+08	63.0	85.6	22.6	92.6	7.0	1.55
2	215	84,000	187	9.988E+05	9.488E+08	63.0	85.6	22.6	92.6	7.0	1.55
3	225	84,000	187	9.988E+05	9.488E+08	63.0	85.6	22.6	92.6	7.0	1.55
4	225	84,000	187	9.988E+05	9.488E+08	63.0	85.6	22.6	92.6	7.0	1.55

Table B-56
Huntington Beach Capacity Factors

Unit	2001	2002	2003	2004	2005	2006	Average
1	36.2%	31.5%	36.5%	38.6%	26.0%	20.4%	31.5%
2	32.4%	37.4%	36.8%	40.8%	22.1%	16.7%	31.0%
3	0.0%	0.0%	8.2%	18.7%	19.3%	11.6%	14.4%
4	0.0%	0.0%	8.9%	17.5%	13.7%	10.8%	12.7%

Table B-57
Huntington Beach Site Meteorological Data

Temperature	Max.	Average	Min.
Huntington Beach inlet temp, °F	69	62	57
Atmos. wet bulb, °F	71	56	30
Atmos. dry bulb, °F	107	63	32

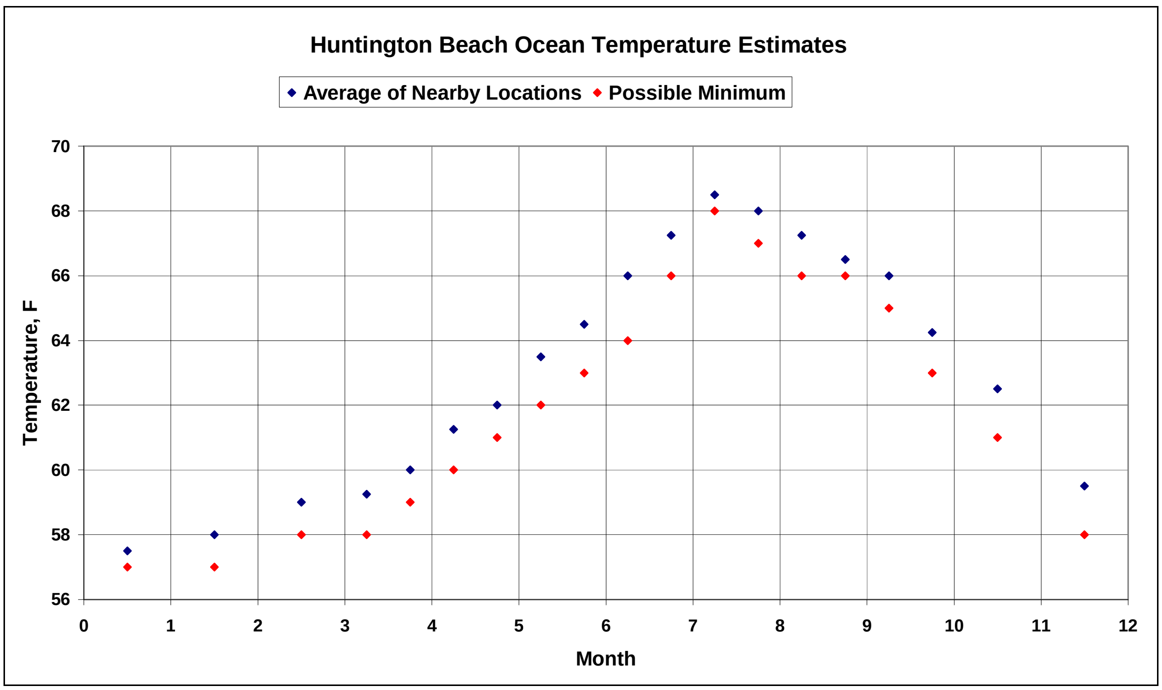


Figure B-49
Huntington Beach Inlet Temperatures

Plant Operating Data

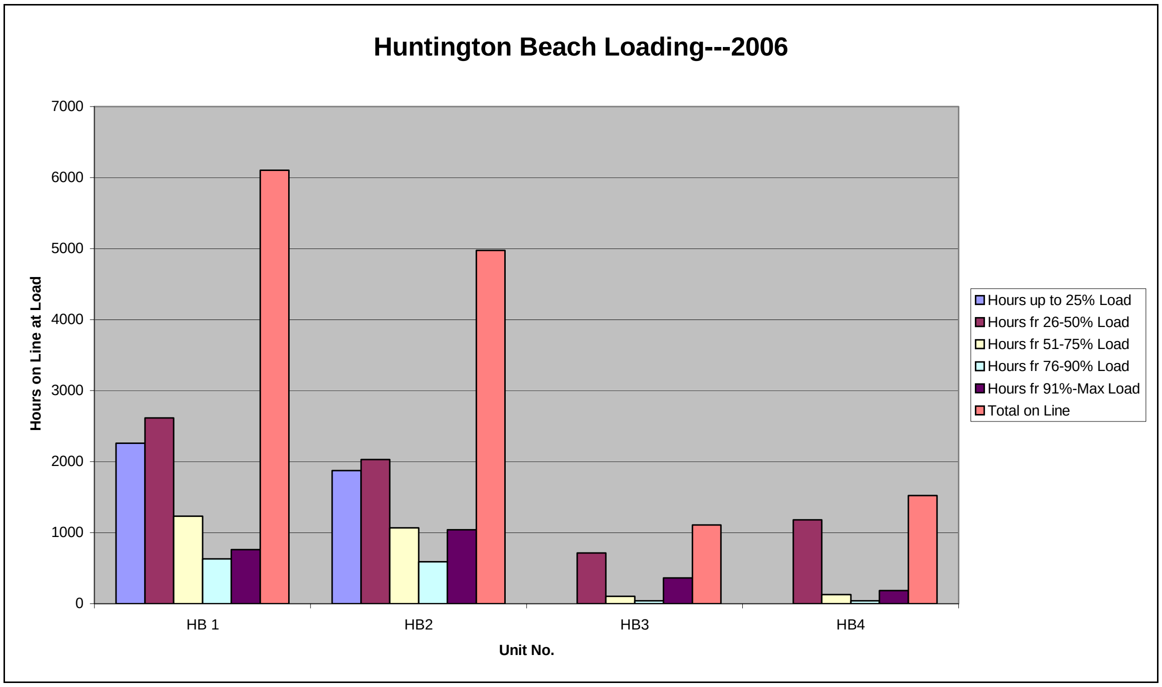


Figure B-50
Huntington Beach Operating Profiles

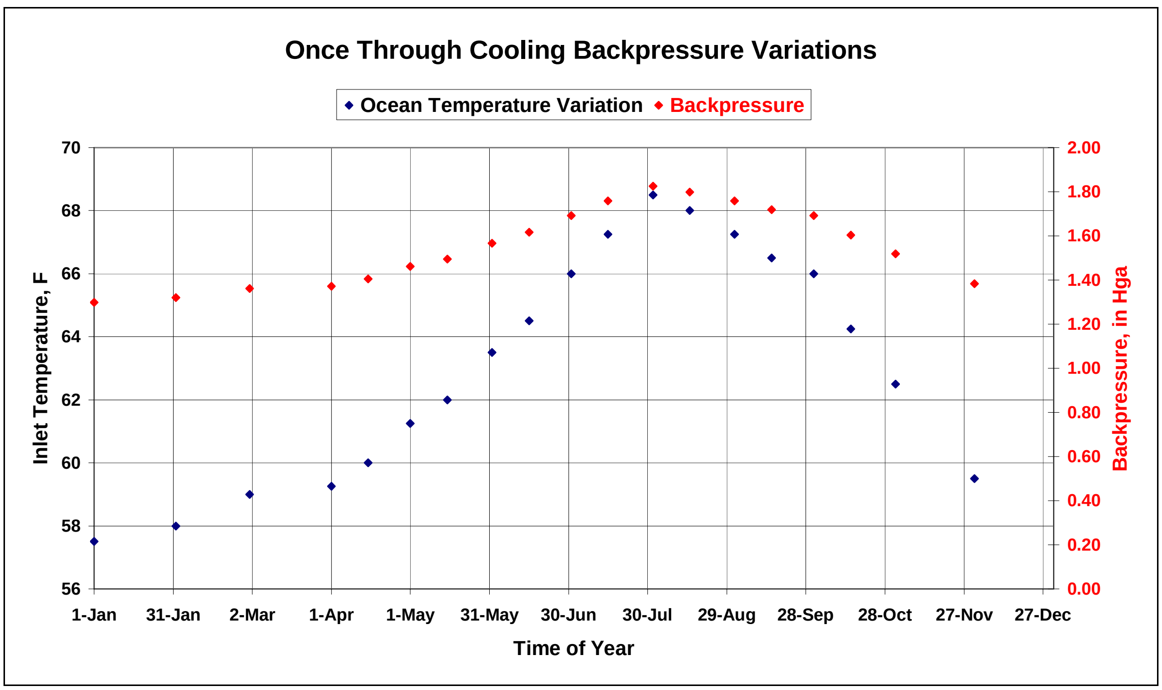


Figure B-51
Once-Through Cooling Backpressure Profile

Cooling Tower Assumptions/Design

- Tower type: mechanical draft, counterflow, FRP construction

- Make-up water source: Sea water; 35,000 ppm salinity
- Operating cycles of concentration: n = 1.5
- Evaporation rate: All units--- ~ 2,200 gpm each
- Make-up rate (@ n = 1.5): All units--- ~ 6,600 gpm each
- Blowdown (@ n = 1.5): All units--- ~ 4,400 gpm each

Tower design conditions are for all circulating water flows and condenser specifications unchanged, an assumed tower approach of 10°F and a peak (1%) wet bulb temperature of 71°F.

This results in a full load condensing temperature on the hottest day of

$$T_{cond} = 71 + 10 + 22.6 + 7 = 110.6°F$$

and a corresponding backpressure of 2.65 in Hga. Over the course of the year when the ambient wet bulb temperature would be lower, the backpressure would vary as indicated in the following figure. A comparison is given to the backpressure estimated with once-through cooling and indicates that the backpressure would normally be elevated by 0.5 to 1. in Hga.

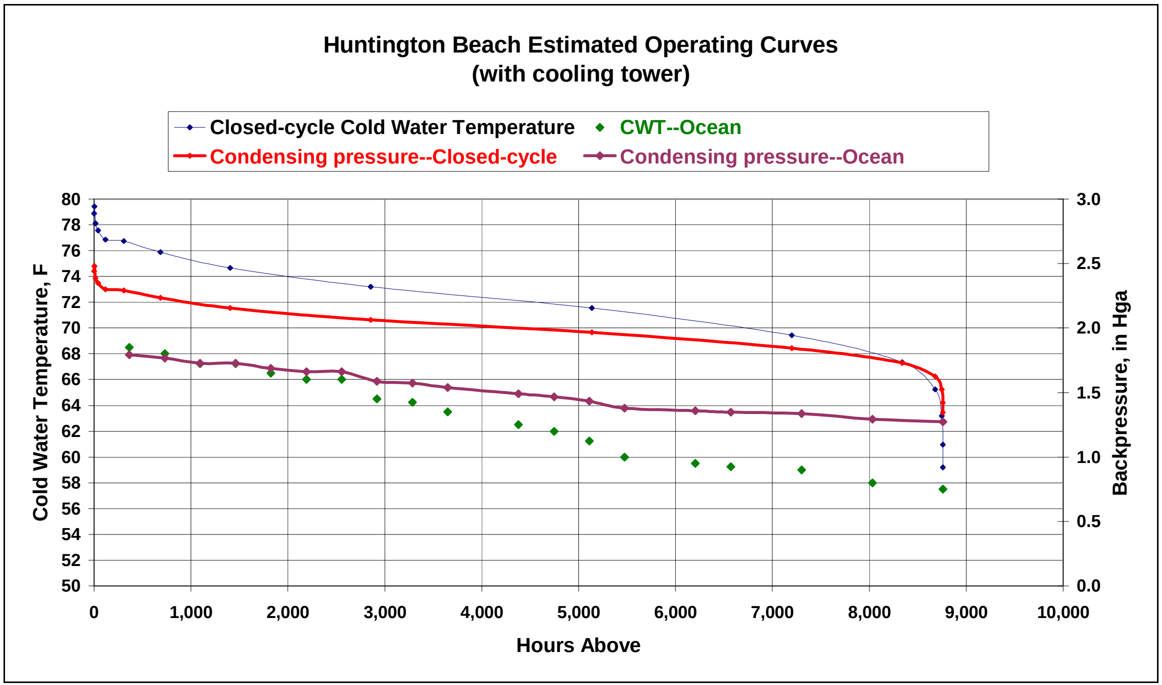


Figure B-52
Comparative Backpressure Performance

Wet Retrofit Costs

Table B-58
S&W Cost Estimates

S&W Costs---escalated to 2007; x 1.07 for seawater					
Unit	**Labor**	**Material**	**Equipment**	**Indirect**	**Total**
1	$5,855,000	$3,408,000	$5,799,000	$8,736,000	$23,798,000
2	$5,855,000	$3,408,000	$5,799,000	$8,736,000	$23,798,000
3	$5,855,000	$3,408,000	$5,799,000	$8,736,000	$23,798,000
4	$5,855,000	$3,408,000	$5,799,000	$8,736,000	$23,798,000
Plant Total	$23,420,000	$13,632,000	$23,196,000	$34,944,000	$95,192,000

Table B-59
Maulbetsch Consulting Survey Estimates

Maulbetsch Consulting Survey; escalated to 2007 $; x 1.07 for salinity			
Unit	**Easy**	**Average**	**Difficult**
1	$14,830,000	$24,717,000	$38,199,000
2	$14,830,000	$24,717,000	$38,199,000
3	$14,830,000	$24,717,000	$38,199,000
4	$14,830,000	$24,717,000	$38,199,000
Plant Total	$59,320,000	$98,868,000	$152,796,000

Dry Cooling

Similar cost estimates can be made for a dry cooling retrofit. The basic assumption is that for plants with low capacity factors, they must be available to produce close to full load on the hottest days of the year when the system load is at its peak.

- Direct dry cooling: forced, mechanical-draft air-cooled condenser
- Steam flow: ~ 1,000,000 lb/hr (Each unit full load)
- Design dry bulb: 100°F (mid-way between 0.4% dry bulb and median of extreme highs)
- Design turbine exhaust pressure: 4.5 in Hga (based on assumption that turbines of this age and design trip at 5 in Hga and that the plant would not wish to reduce output on the hottest days)
- Corresponding condensing temperature: 130 ºF

Therefore, ACC design ITD ($T_{condensing}$ - $T_{design\ ambient}$) = 130°F – 100°F = **30°F**

Dry Cooling Retrofit Costs

AC costs can be roughly estimated from EPRI Report No. 1005358; "Comparison of Alternate Cooling Technologies for U.S. Power Plants", August, 2004.

Vendor information for a design of:

Steam flow: 1,000,000 lb/hr (scaled from example case of 1,128,000 lb/hr)
ITD: 30°F

Price: 2007 $

Table B-60
Dry Cooling Retrofit Cost Estimates

Source/Basis	Equip't	Erection	Electrical	Duct work	Total	Cells
Vendor 1	18,000,000	7,700,000	900,000	150,000	26,750,000	30
Vendor 2	14,900,000	7,300,000	900,000	150,000	23,250,000	30
Average	16,450,000	7,500,000	900,000	150,000	25,000,000	30
Scaled to 2007$	$20,562,500	$9,375,000	$1,125,000	$187,500	$31,250,000	
Including indirects	$32,488,750	$14,812,500	$1,777,500	$296,250	$49,375,000	
Plant total	**$129,955,000**	**$59,250,000**	**$7,110,000**	**$1,185,000**	**$197,500,000**	

Comparison with Individual Design Studies

An estimate of retrofit costs for both wet and dry cooling was performed for Huntington Beach by Sargent & Lundy on August, 2005. (S&L Report No. 11831-013) The agreement with estimates made in this study and discussed above was quite good as shown in the table below.

Cooling system	This study	Sargent & Lundy
Wet	$95,192,000/$98,868,000	$102,408,000
Dry	$197,500,000	$202,795,000

A second estimate was prepared for the Coast Law Group by Powers Engineering (Letter to Coast Law Group, LLC dated July 29, 2006). This estimate for wet closed-cycle cooling was approximately 20% lower at $80,000,000. The lack of agreement appears to be attributable primarily to two items.

First, the use of plume abatement towers was assumed. The costs were about x 1.3 to x 2 times what was estimated in this study for the cooling tower alone and this is consistent with the usual assumptions about the relative cost of plume abatement vs. conventional wet towers. This would have been expected to cause this estimate to be higher. However, the total project costs were factored from the tower costs by assuming that the tower costs were about 40% of the retrofit costs. This simple factoring, as was discussed in an earlier section, always fails to capture any site-dependent features and results in an estimate that is normally too low. This was shown to be the case in comparisons of the survey data with factored estimates from EPA and appears to have resulted in an estimate in this case which is quite low compared to other estimates which are reasonably consistent.

Effect on Plant Performance

A retrofitted cooling system of either the wet or dry type would have a deleterious effect on the plant net heat rate. This arises from two effects:

1. Considering only the wet system, the power requirements will be higher than the current pumping power requirements for the once-through system. This power is used for the additional circulating pumps and for the cooling tower fans and represents power that must be generated but cannot be sold.
2. The plant will operate at a higher backpressure and therefore a higher heat rate with closed cycle cooling. This effect will be much more pronounced for a dry system than for a wet system.

The additional power requirements are estimated as follows:

Pumping power: The circulating water flow rate must be pumped through an additional head rise. This will be estimated at 40 feet to account for the lift out of the sump, the rise to the hot water distribution deck on the top of the tower and the head loss through the circulating water lines. A combined pump/motor efficiency of 75% is assumed. Each of these factors would be refined in a detailed analysis, but these are considered adequate to give a reasonable estimate of the effect of additional operating power on the plant. For the several units at Huntington Beach:

Table B-61
Huntington Beach Units: Retrofit Additional Pumping Power

Unit	Flow	Head	Eff	Power	Motor
	gpm	ft		kW	MW
1	84,000	40	0.75	632.7	0.84
2	84,000	40	0.75	632.7	0.84
3	84,000	40	0.75	632.7	0.84
4	84,000	40	0.75	632.7	0.84

Fan power: Similarly cooling tower fan power can be roughly estimated. It is assumed for retrofits on older, lower capacity factor units, the tower would be sized to "low first cost" design since the number of operating hours is low and power penalties are less severe. This is consistent with the assumptions made in the retrofit capital cost estimates. The number of cells will be estimated as one cell per 10,000 gpm of circulating water flow, the fan horsepower at 200 HP and a motor efficiency of 90%. For the Huntington Beach units this results in:

Table B-62
Huntington Beach Units: Retrofit Fan Power

Unit	Flow	Cells	Eff	Power	Motor
	gpm	n		hp	kW
1	84,000	8	0.9	1,600	1,326
2	84,000	8	0.9	1,600	1,326
3	84,000	8	0.9	1,600	1,326
4	84,000	8	0.9	1,600	1,326

This represents a combined, full-load operating power requirement of approximately 9. MW or approximately 1.% of the plant power rating of 900 MW. The actual annual cost will obviously depend on the capacity factor, the number of hours on-line, and whether some fans are turned off when operating at part load. Also, the cooling system was sized for full load at acceptable backpressures at so-called "1%" ambient conditions, it would be well oversized for nearly the entire year. Therefore, the effect of requiring additional operating power for the pumps and fans coupled with operation at higher heat rate would be an increase in the fuel burned rather than a reduction in plant output.

Heat rate penalty: As seen in the earlier plot of comparative backpressure, the condensing pressure with closed-cycle wet cooling will run typically 0.5 to 1.0 in Hga higher than it would with once-through ocean cooling and increases to about 2.65 in Hga on the hottest days. The effect is less at part load. Information for turbines of similar type and age indicate a heat rate penalty of approximately 0.25% for each increase in backpressure of 0.1 in Hga above design. The comparative plot shown earlier suggests that closed cycle cooling will result in increased backpressure throughout the year ranging from 0.5 to 1. in Hga with a corresponding heat rate penalty of 0.5 to 1.%.

Capacity Limits

The increased back pressure will likely results in an output restriction at the hottest day. The magnitude of the shortfall will depend on the operating philosophy. If the firing rate is held constant, a 1% heat rate penalty would correspond to roughly a 1% reduction in output.

If, however, it were to be decided that operation at a backpressure of 2.65 in Hga constituted an unacceptable maintenance risk to the turbine, then the firing rate would need to be reduced to hold whatever backpressure was consider acceptable. Information to estimate what the shortfall would be in that case is not available but presumably could be estimated by plant staff based on the information given above.

Maintenance Costs

Commonly used factors for maintenance (labor, materials, chemicals, etc.) for wet cooling systems range from 2. to 3. % of the system capital costs. For wet systems, the important costs are for water treatment, biofouling control and keeping the basin clean. Using salt water and having salt drift around the plant would require rust control, extra painting, etc. Using the high end of typical factors, assume 3. to 3.5% of the capital cost of the tower. It is unclear how AES would allocate these costs between operation and maintenance, but an estimate of 3% of the "average" capital costs for all units of $60 million could amount to approximately $1,800,000 per year.

Additional Cost Considerations

Although the S&W costs are pretty close to the Maulbetsch Consulting survey's "Average" difficulty estimate, neither of those estimates can account for many site-specific difficulties which might be encountered at the Huntington Beach site. Those items that could cause a retrofit at this site to be in a different, either "High" or "Easy" category include:

- Difficulty in locating the tower
- Unusual site preparation costs
- Significant interferences to the cost of installation of the circulating water lines
- The need for cooling tower plume abatement
- Stringent noise control
- The use of an alternate make-up water

Location of Tower/Unusual Site Preparation Costs/Interferences

It appears that space would be available for cooling towers in two locations:

i. The areas north and east of the plant at locations currently occupied by fuel and storage tanks which are no longer in use. Towers for Units 1 and 2 might be placed in the area occupied by the “east” fuel oil tank and the distillate storage tank. Lines from that location would be about 800 feet long. Towers for Units 3 and 4 would be farther away to the Northeast. Lines from there would be about 1,200 feet long. These circulating water lines would traverse much of the site and would likely encounter many underground interferences.

ii. It might also be possible to locate towers between the plant and the beach in a strip of land just inside the site boundary. The towers would be closer but the lines, while shorter, would have to go around and close to the plant buildings with an increased likelihood of numerous underground interferences.

All locations had serious drawbacks including

i. The need to demolish, relocate and rebuild existing structures for some locations.

ii. The possibility that the soil near the old tank farms would have been contaminated and that disturbing the ground and having to clean or dispose of the soil as a contaminated waste.

iii. Unstable soil conditions requiring significant foundation work such as deep pilings to stabilize the towers. There is no information on which to evaluate this issue, but given the location close to the shore, it is likely that the ground could be saturated, requiring special and costly excavation procedures and extra foundation work.

iv. Drift deposition from salt water towers.

v. Probable neighborhood objections to visible plumes, corrosive drift and noise.

vi. The need for PM10 offsets for expected drift from seawater towers.

Plume Abatement

Based on the view in the aerial photo of the neighboring area, it appears that a visible plume could be a serious issue at this site primarily from an aesthetic viewpoint. It is reasonable to assume that a plume abatement tower would be required to ameliorate any problems from a plume visible from residential areas and from the beach. Plume abatement towers have an air-cooled section on top of the wet tower. The hot water is pumped to the top of the tower, passes down through the dry section and then discharged onto the hot water distribution deck of the wet section. The air passing across the finned tubes of the dry section mixes with the wet plume coming off the wet section and keeps it from becoming saturated and condensing in the cold atmosphere. The need for a plume abatement tower would increase both the capital cost of the tower itself by a factor of perhaps 2. to 2.5 and the additional pumping power by an additional 30 to 50% due to the greater height to which the hot water must be pumped.

Aesthetics

In addition to any issues with a visual plume, the simple appearance of a cooling tower is sometimes considered an aesthetic affront. In this instance, the towers would be visible to neighbors and from the beach. Considering the number, size and bulk of the plant buildings already present, this may not present a major problem. However, given the prevailing attitudes with regard to scenic issues on the coast and from recreational areas, it may turn out to be a contentious, time-consuming and costly issue.

Noise Control

Noise from wet cooling towers comes both from the fans and from the water cascading through the fill. Fan noise can be diminished by fan design or the reduction in air velocity which sometime requires the use of bigger, or more, cells. The water noise is more difficult to reduce and usually requires the construction of sound barriers around the cooling tower. As in the case of the plume abatement question, the aerial photo of the plant and the neighboring area including the beach makes it appear that cooling tower noise may be a serious constraint. In the case that it is, the capital cost of the tower itself cost might increase from 20 to 40%.

Alternate Sources of Make-Up Water

The use of seawater make-up can introduce intractable problems regarding drift and related maintenance considerations. (See later discussion of drift and PM10.) An alternative can be to purchase reclaimed water from nearby municipal water treatment facilities.

In this instance, however, possibility of using reclaimed water for wet cooling tower makeup was considered and rejected due to the distance of sources from the plant, the expected very high cost of installing delivery and return pipelines to the remote sources and the expected extended time required to obtain permits even if the approach were deemed feasible.

Shutdown Period

There is often concern over the period of post plant availability during the retrofit construction period. In this instance, it appears that the major part of the construction could be done while the plant is on-line, with shutdown required only for the final tie-in of the circulating water lines to the existing water circuit. There is no information available to estimate how long this might be. However, the operating profiles shown earlier, especially for Units 3 and 4, indicate periods of little or no operation. Therefore, it appears that the tie-in could be accomplished with no serious downtime.

Other Environmental Issues

Retrofit to a closed-cycle cooling system introduces some environmental issues which a once-through cooling system does not. These are increased air emissions from the stack and drift from the cooling tower.

Stack Emissions

In an earlier section it was noted that a closed-cycle retrofit increase the unit net output because of heat rate penalties and the use of increased operating power. In this instance these together were estimated at from 1 to 2%. Therefore, the delivery of the same amount of electric power to the grid will require the burning of additional fuel at some location to make up that lost at Huntington Beach. Based on the unit heat rate information provided, this does not appear to be major effect in this case. Furthermore, in the discussion of this issue in Chapter 7, it was pointed out that the effect of making up this shortfall was highly variable depending on how and where the replacement per was generated. Therefore, no attempt is made to asses the effect in quantitative terms beyond pointing out that reliable estimates of the shortfall to be expected from full load operation can be made.

Drift

It is assumed that any cooling tower would be equipped with state-of-the-art drift eliminators rated at about 0.0005% of circulating water flow. The following table estimates the amount of drift to be expected from such designs. In addition, as discussed earlier, Federal EPA and State regulations characterize all solids carried off in cooling tower drift as PM10. The cost of offsetting this amount, should it be necessary will vary considerably from site to site as will the severity of the regulatory constraints.

Table B-63
Huntington Beach Drift Estimates

Unit	Flow	Drift[1]	Drift	PM10	PM10	Cap. Factor	PM10
	gpm	gpm	lb/hr	lb/hr	tons/year[2]	%	tons/year[3]
1	**84,000**	0.42	210	10.50	46.0	**24.7**	**11.4**
2	**84,000**	0.42	210	10.50	46.0	**24.7**	**11.4**
3	**84,000**	0.42	210	10.50	46.0	**24.7**	**11.4**
4	**84,000**	0.42	210	10.50	46.0	**25.7**	**11.8**

1. At drift eliminator efficiency of 0.0005%
2. Assumes full load all year
3. At 2006 capacity factor

General Conclusion

On balance, it is concluded that there are a number of likely problems and additional costs to be encountered at Huntington Beach which would put the retrofit at this site in a “difficult” category. Based on the results from the Maulbetsch Consulting survey presented above, this would put the project cost in the range of $150. million. Given the capacity factors, particularly for Units 3 and 4, a retrofit effort of this cost may be an uneconomical option.

B.7 Harbor Generating Station (Los Angeles Department of Water and Power)

Location

161 N. Island Street
Wilmington, CA 90744
Contact: Katherine Rubin, 213-367-0436
33° 45’ 56.56” N; 118° 15’ 47.53”

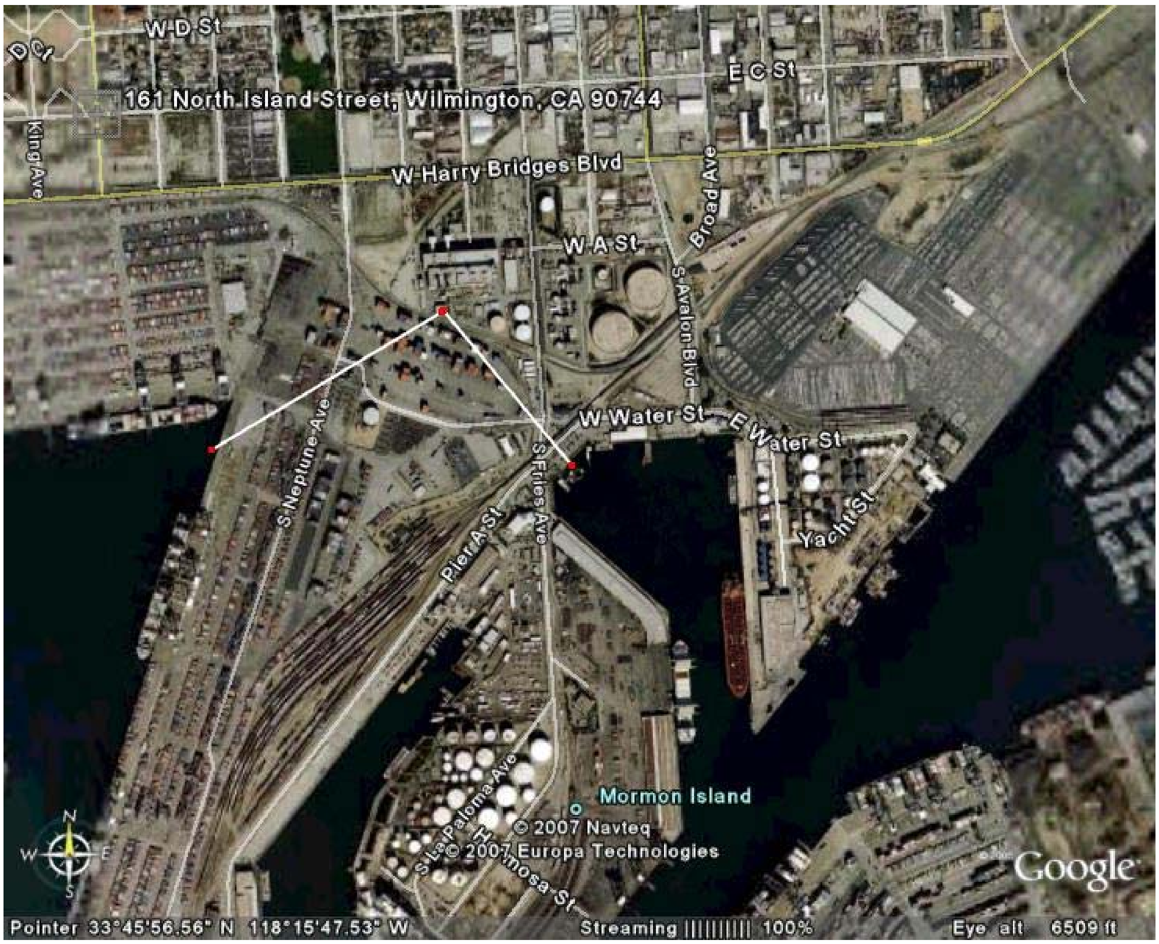


Figure B-53
Harbor Generating Station Boundaries and Neighborhood

Figure B-54
Harbor Generating Station Site View

Plant/Site Information

Units 1 and 2: 80 MW combustion turbines
Unit 5: 75 MW heat recovery steam turbine with Units 1 and 2

Table B-64
Harbor Cooling System Operating Conditions

Unit	MW	Cooling Water flow		Steam flow	Heat duty	Tin	Tex	Range	Tcond	TTD	Backpressure
		gpm	cfs	lb/hr	Btu/hr	F	F	F	F	F	in Hga
5	75	56,400	125	6.0E+05	5.70E+08	63.0	83.0	20.0	90.0	7.0	1.42

Table B-65
Harbor Capacity Factors

Unit	2001	2002	2003	2004	2005	2006	Average
5	28.4%	31.7%	24.9%	15.1%	13.5%	9.1%	20.5%

Table B-66
Harbor Site Meteorological Data

Temperature	Max.	Average	Min.

Harbor water, °F	68	63	57
Atmos. wet bulb, °F	70	57	30
Atmos. dry bulb, °F	90*	65	35

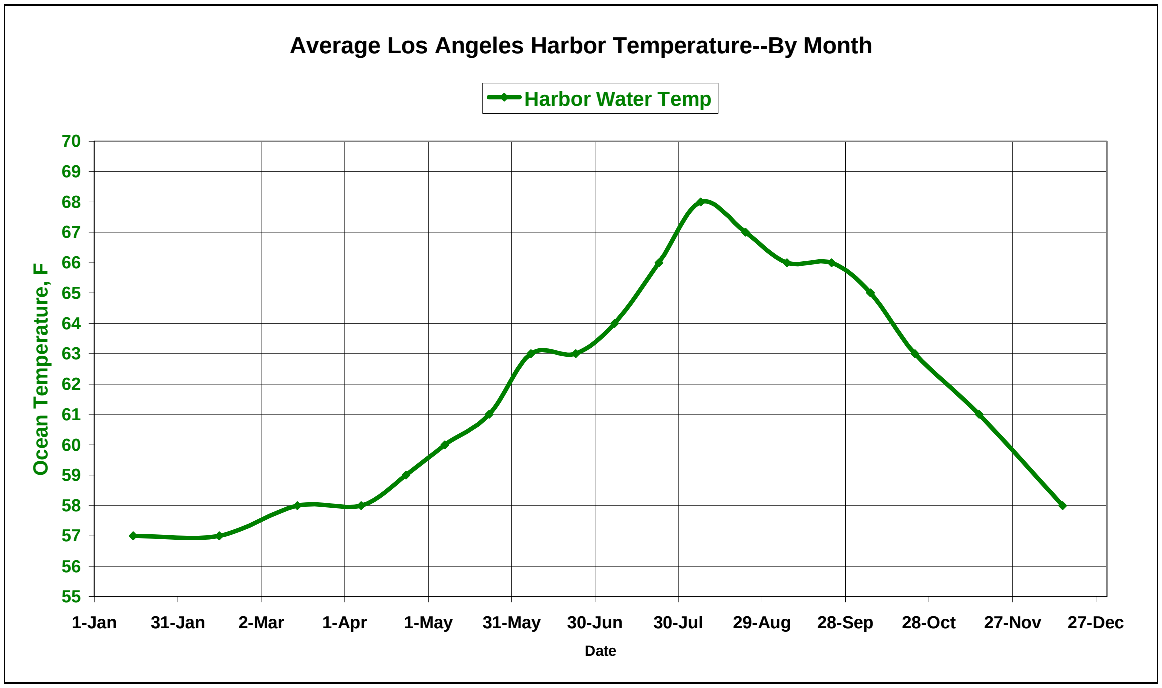


Figure B-55
Harbor Generating Station Inlet Temperature

Plant Operating Data

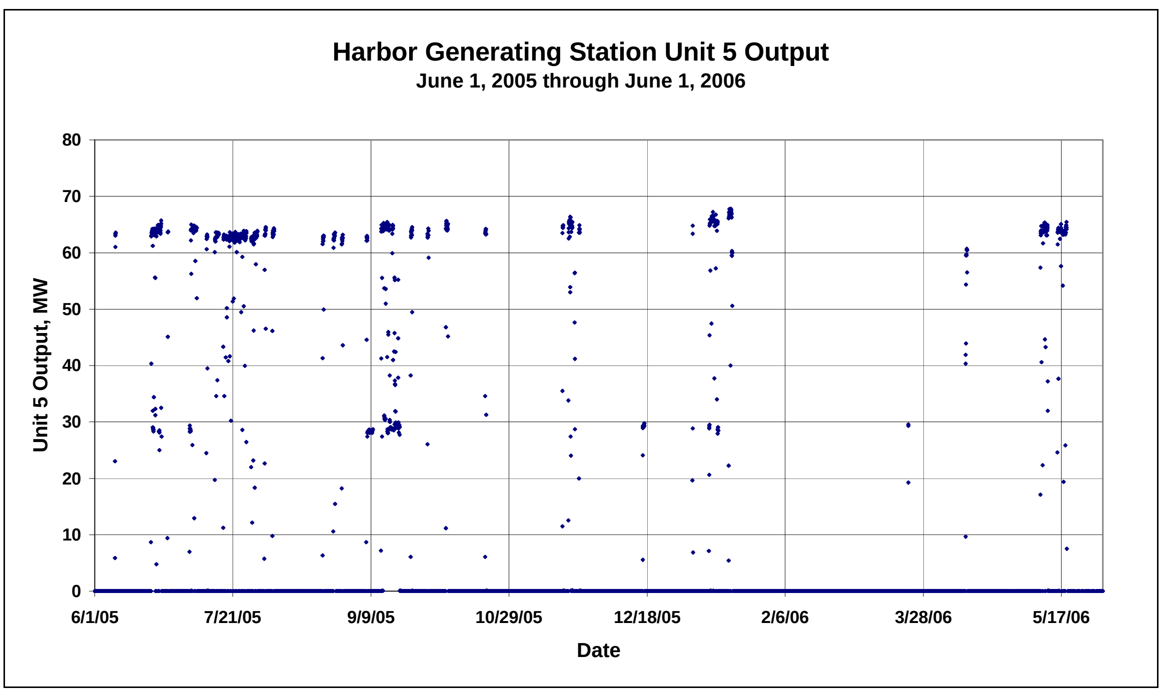


Figure B-56
Harbor Unit 5 Output in 2005/2006

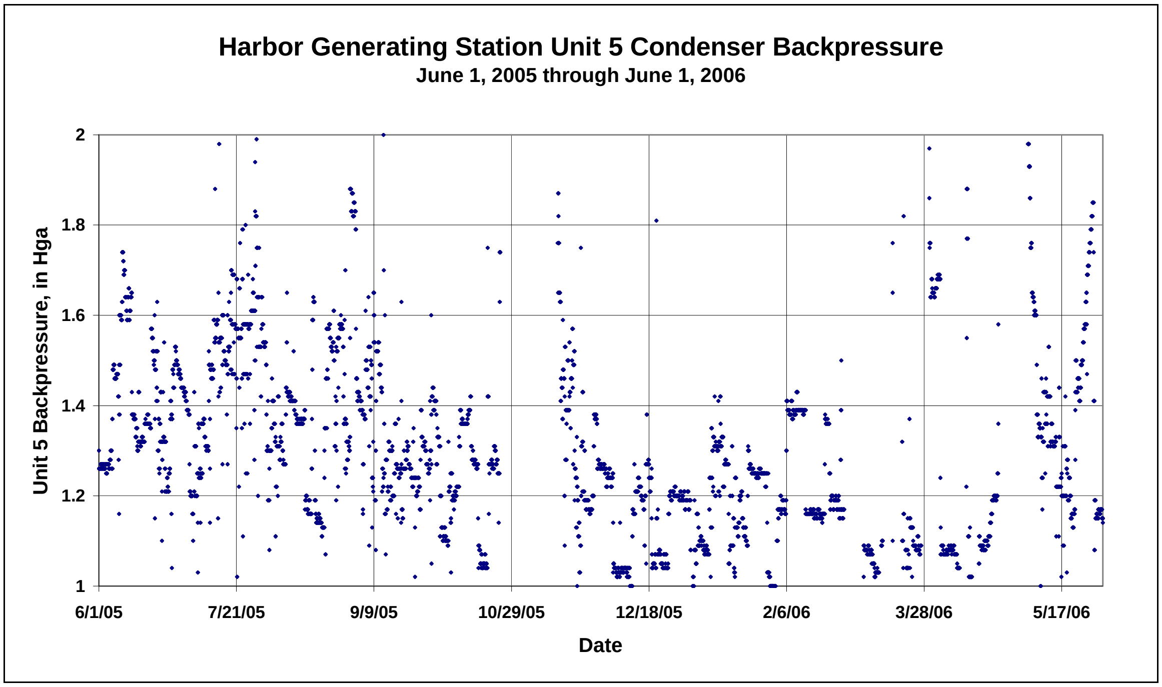


Figure B-57
Harbor Unit 5 Backpressure in 2005/2006

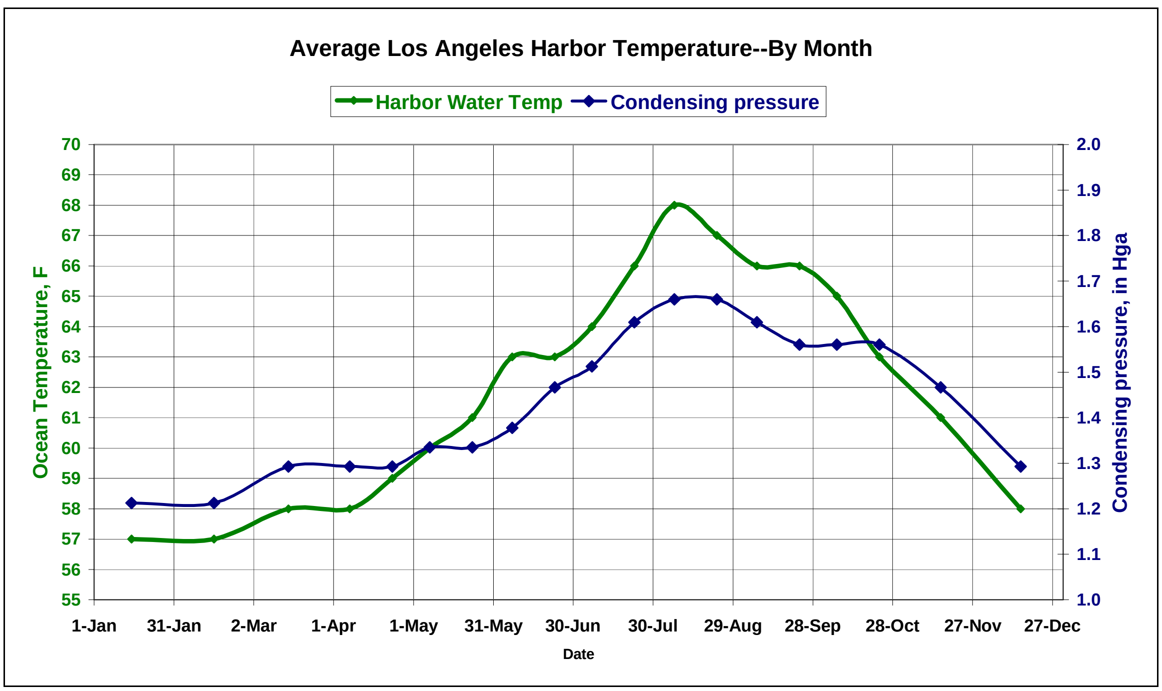


Figure B-58
Backpressure and Ocean Temperature (Estimated from Condenser Specs for Full Load)

Cooling Tower Assumptions/Design

Wet cooling system design specs for Unit 5 (full load)

- Tower type: mechanical draft, counterflow, FRP construction
- Make-up water source: Sea water; 35,000 ppm salinity
- Operating cycles of concentration: n = 1.5
- Evaporation rate: Unit 5--- ~ 700 gpm
- Make-up rate (@ n = 1.5): Unit 5--- ~2,100 gpm
- Blowdown (@ n = 1.5): Unit5--- ~ 1,400 gpm

Tower design specifications (to conform to once-through cooling system operating conditions)

- Circulating water flow: 56,400 gpm (unchanged)
- Range: 20°F (unchanged)
- Condenser TTD: 7°F (unchanged)
- Design wet bulb: 70°F (peak conditions)
- Tower approach: 10°F ($T_{cond} - T_{wb}$) (typical)

Therefore, on the hottest day corresponding to probable peak demand:

- Condensing temperature = 70 + 10 + 20 + 7 = 107°F
- Condensing pressure = ~ 2.5 in Hga

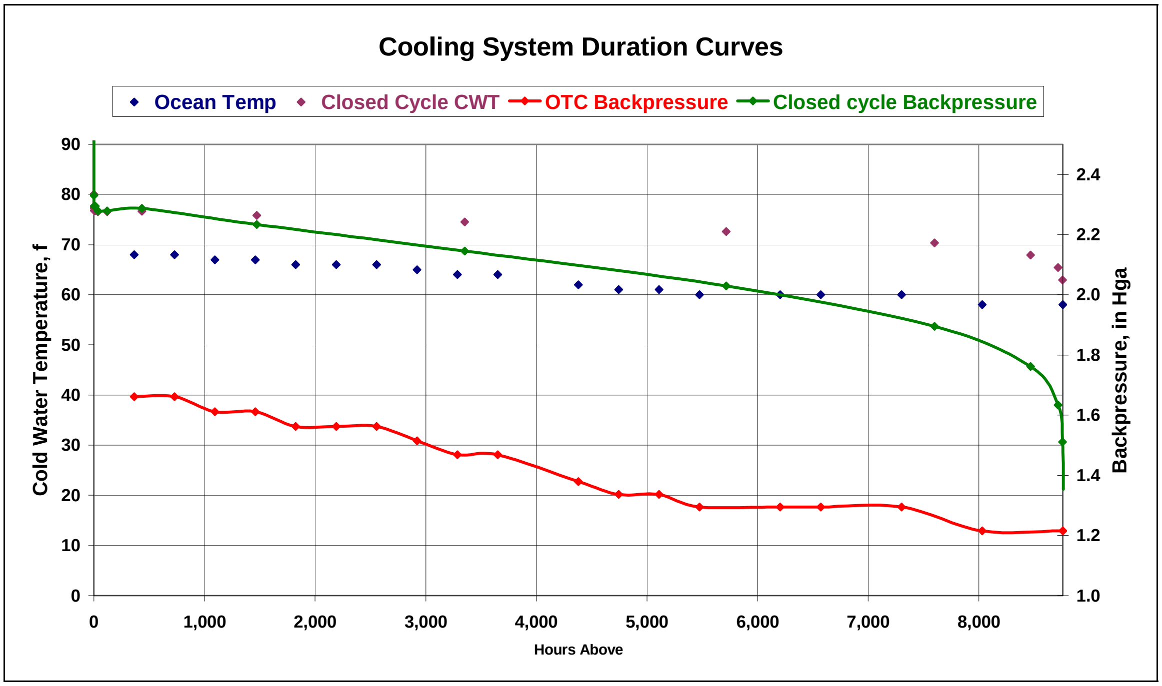


Figure B-59
Backpressure Comparisons—Full Load for Year

Wet Retrofit Costs

Table B-67
S&W Cost Estimates

S&W Costs---escalated to 2007; x 1.07 for seawater					
Unit	Labor	Material	Equipment	Indirect	Total
5	$3,967,285	$2,312,609	$3,933,257	$5,923,628	$16,136,779
Plant Total	$3,967,285	$2,312,609	$3,933,257	$5,923,628	$16,136,779

Table B-68
Maulbetsch Consulting Survey Estimates

Amounts	Easy 165/gpm	Average 275/gpm	Difficult 425/gpm
2007 $	$9,306,000	$15,510,000	$23,970,000
x1.07 for salinity	$9,957,420	$16,595,700	$25,647,900

Dry Cooling

Similar cost estimates can be made for a dry cooling retrofit. The basic assumption is that for plants with low capacity factors, they must be available to produce close to full load on the hottest days of the year when the system load is at its peak. Therefore,

- Direct dry cooling: forced, mechanical-draft air-cooled condenser
- Steam flow: ~ 600,000 lb/hr (Unit 5 full load)
- Design dry bulb: 90°F (mid-way between 0.4% dry bulb and median of extreme highs)
- Design turbine exhaust pressure: 4.5 in Hga (based on assumption that turbines of this age and design trip at 5 in Hga and that the plant would not wish to reduce output on the hottest days)
- Corresponding condensing temperature: 130°F

Therefore, ACC design ITD ($T_{condensing}$ - $T_{design\ ambient}$) = 130°F – 90°F = **40°F**

AC costs can be roughly estimated from EPRI Report No. 1005358; “Comparison of Alternate Cooling Technologies for U.S. Power Plants”, August, 2004.

Vendor information for a design of:

Steam flow: 600,000 lb/hr (scaled from example case of 1,080,000 lb/hr)
ITD: 40°F
Price: 2002 $

Table B-69
Dry Cooling Retrofit Cost Estimate

Source/Basis	Equip't	Erection	Electrical	Duct work	Total	Cells
Vendor 1	$10,000,000	$4,278,000	$500,000	$150,000	$14,861,000	18
Vendor 2	$8,278,000	$4,056,000	$500,000	$150,000	$12,917,000	18
Average	$9,139,000	$4,167,000	$500,000	$150,000	$13,889,000	18
Scaled to 2007$	$11,424,000	$5,208,000	$625,000	$188,000	$17,361,000	
Including indirects	$18,050,000	$8,229,000	$988,000	$297,000	$27,430,000	

This cost substantially exceeds the estimates for the wet cooling retrofit. An 18 cell tower would likely be in a 6 x 3 array of cells approximately 50 x 50 in plan area. The top of the steam duct would be about 100’ elevation. The footprint of an ACC of this size is crudely sketched on the aerial photo below in what appears to be the only available space. Additionally, the running of a large steam duct from the turbine exhaust to the ACC in this location would be costly, although not impossible, and would further increase the costs above. The installation of an ACC on a unit of this size, age and capacity factor appears to be unreasonable and will not be considered further in this discussion.

Figure B60
Rough Sizing and Location for ACC

Effect on Plant Performance

A retrofitted cooling system of either the wet or dry type would have a deleterious effect on the plant net heat rate. This arises from two effects:

1. Considering only the wet system, the power requirements will be higher than the current pumping power requirements for the once-through system. This power is used for the additional circulating pumps and for the cooling tower fans and represents power that must be generated but cannot be sold.
2. The plant will operate at a higher backpressure and therefore a higher heat rate with closed cycle cooling. Two considerations are important. First, the HRSG at Harbor is not equipped with auxiliary burners. Therefore, ambient temperature and humidity effects on the gas turbine exhaust temperature and mass flow adversely affect the output of the steam cycle and cannot be compensated for. As a result, and because this is primarily a peaking facility, heat rate penalties are very important to the economical operation of the station. Second, extended operation at 2.5 in Hga is considered by plant staff to be an unacceptable maintenance risk. This consideration would be much more significant for a dry system than for a wet system.

The additional power requirements are estimated as follows:

Pumping power: The circulating water flow rate must be pumped through an additional head rise. This will be estimated at 40 feet to account for the lift out of the sump, the rise to the hot water distribution deck on the top of the tower and the head loss through the circulating water lines. A combined pump/motor efficiency of 75% is assumed. Each of these factors would be refined in a detailed analysis, but these are considered adequate to give a reasonable estimate of the effect of additional operating power on the plant. For the Harbor Unit 5:

Table B-70
Harbor Unit 5: Retrofit Additional Pumping Power

Flow	Head	Eff	Power	Motor
gpm	ft		kW	MW
56,400	40	0.75	424.8	0.57

Fan power: Similarly cooing tower fan power can be roughly estimated. It is assumed for retrofits on older, lower capacity factor units, the tower would be sized to "low first cost" design since the number of operating hours is low and power penalties are less severe. This is consistent with the assumptions made in the retrofit capital cost estimates. The number of cells will be estimated as one cell per 10,000 gpm of circulating water flow, the fan horsepower at 200 HP and a motor efficiency of 90%. For Harbor Unit 5 this results in:

Table B-71
Harbor Unit 5: Retrofit Fan Power

Flow	Cells	Eff	Power	Motor
gpm	n		hp	kW
56,400	6	0.9	1128	935

This represents a combined, full-load operating power requirement of approximately 1.5 MW or 2% of the Unit 5 power rating of 75 MW. The actual annual cost will obviously depend on the capacity factor, the number of hours on-line, and whether some fans are turned off when operating at part load. Also, the cooling system was sized for full load at acceptable backpressures at so-called "1%" ambient conditions, it would be well oversized for nearly the entire year. Therefore, the effect of requiring additional operating power for the pumps and fans coupled with operation at higher heat rate would be an increase in the fuel burned rather than a reduction in plant output.

Heat rate penalty: As seen in the earlier plot of comparative backpressure, the condensing pressure with closed-cycle wet cooling will run typically 0.5 to 1.0 in Hga higher than it would with once-through ocean cooling and increases to about 2.5 in Hga on the hottest days. The effect is less at part load. Discussions with plant staff indicated a heat rate penalty of approximately 1,000 Btu/kWh when going from 1.5 to 2.5 in Hga backpressure or approximately at 10% penalty at full load, perhaps averaging 5% over the entire year.

Capacity Limits

The increased back pressure will likely result in an output restriction at the hottest day. The magnitude of the shortfall will depend on the operating philosophy. If the firing rate is held constant a 10% heat rate penalty would correspond to roughly a 10% reduction in output. If the decision were made to overfire the unit, if this is possible, the shortfall could be reduced but the heat rate penalty and hence the fuel costs, would increase even further. In addition, if it were to be decided that operation at a backpressure of 2.5 in Hga constituted an unacceptable maintenance risk to the turbine, then the firing rate would need to be reduced to hold whatever backpressure was consider acceptable. Information to estimate what the shortfall would be in that case is not available but presumably could be estimated by plant staff based on the information given above.

Maintenance Costs

Commonly used factors for maintenance (labor, materials, chemicals, etc.) for wet cooling systems range from 2. to 3. % of the system capital costs.

For wet systems, the important costs are for water treatment, biofouling control and keeping the basin clean. Using salt water and having salt drift around the plant would require rust control, extra painting, etc. Using the high end of typical factors, assume 3. to 3.5% of the capital cost of the tower. It is unclear how LADWP would allocate these costs between operation and maintenance, but an estimate of 3% of the "average" capital cost of $16.6 million would amount to approximately $500,000 per year.

Additional Cost Considerations

Although the S&W costs are pretty close to the Maulbetsch Consulting survey's "Average" difficulty estimate, neither of those estimates can account for any site-specific difficulties which might be encountered at the Harbor site. Those items that could cause a retrofit at this site to be in a different, either "High" or "Easy" category include:

- Difficulty in locating the tower
- Unusual site preparation costs
- Significant interferences to the cost of installation of the circulating water lines
- The need for cooling tower plume abatement
- Stringent noise control
- The use of an alternate make-up water

Location of Tower/Unusual Site Preparation Costs/Interferences

Reference to the site photos at the beginning of this write-up suggests that the locations either to the east or west of the plant would be available for wet towers although not for ACC's.

- The east location is closer with shorter circulating water lines but the soil is wet and unstable. Dewatering would be necessary during both the siting of the tower basin and the installation of the circulating water lines. In addition, pilings would likely be required to support the tower.
- The west location is further away but may present fewer interferences to the installation of the circulating water lines. However, the same unfavorable soil conditions exist in this location as well.
- The costs for site prep and installation of the circulating water lines in the S&W spreadsheets, typically together, are greater than the tower itself. If these costs were to double due to either of these conditions, it could easily add 5. to 10. million to the cost of the project.
- If the location suggested above is usable, the new circulating water lines would not be very long. This would lead to an “easy/average” cost depending on the number of interferences that you would run into and the cost of excavation as we discussed above. Costs for “easy installation” have been estimated at $11/in-dia/ft. The circulating water lines that were installed at Moss Landing during the construction of new Units 1 and 2 ran across the old plant property ran to literally hundreds of interferences, and the cost was several times the $11/in-ft.
- Given that there are old fuel tanks in the immediate area, there may be contaminated soil in areas where the towers would be located, which if disturbed, might entail high clean-up costs.

Plume Abatement

Based on the view in the aerial photo of the neighboring area, it does not appear that a visible plume would be a serious issue at this site either from a safety or an aesthetic viewpoint. If it were to be, however, a plume abatement tower would be required. Plume abatement towers have an air-cooled section on top of the wet tower. The hot water is pumped to the top of the tower, passes down through the dry section and then discharged onto the hot water distribution deck of the wet section. The air passing across the finned tubes of the dry section mixes with the wet plume coming off the wet section and keeps it from becoming saturated and condensing in the cold atmosphere. The need for a plume abatement tower would increase both the capital cost of the tower itself by a factor of perhaps 2. to 2.5 and the additional pumping power by an additional 30 to 50% due to the greater height to which the hot water must be pumped.

Aesthetics

In addition to any issues with a visual plume, the simple appearance of a cooling tower is sometimes considered an aesthetic affront. Again, in this instance, given the commercial nature of the surrounding neighborhood and the bulk of the plant buildings already on-site, it does not appear that this would present a problem.

Noise Control

Noise from wet cooling towers comes both from the fans and from the water cascading through the fill. Fan noise can be diminished by fan design or the reduction in air velocity which sometime requires the use of bigger, or more, cells. The water noise is more difficult to reduce and usually requires the construction of sound barriers around the cooling tower. As in the case of the plume abatement question, the aerial photo of the plant and the neighboring area makes it appear that cooling tower noise should not be a serious constraint. In case that it is, the capital cost of the tower itself cost might increase from 20 to 40%.

Alternate Sources of Make-Up Water

It may be that the use of seawater make-up would introduce intractable problems regarding drift and related maintenance considerations. (See later discussion of drift and PM10.) An alternative would be to purchase reclaimed water from a nearby municipal water treatment facility.

Usually, the major cost is providing the pipeline to deliver the water to the site which, in urban environments could be between $1. to $2. million per mile (based on recent studies in Farmington, New Mexico, a much less congested environment). In the case of Harbor, tertiary treated RO water flows through a pipeline passing just to the west of the plant. It is not clear whether this water would be available since it is currently being used for Harbor Generating Station’s demineralization process, for irrigation and in injection wells to hold back salt water intrusion. In addition, the reliability of the supply has been uncertain in the past although it is reported to be improving. If available for use, the cost of the retrofit would be reduced with the elimination of the need to design the tower for salt water. (See earlier discussion of cost estimates.)

Shutdown Period

There is often concern over the period of post plant availability during the retrofit construction period. In this instance, it appears that the major part of the construction could be done while the plant is on-line, with shutdown required only for the final tie-in of the circulating water lines to the existing water circuit. There is no information available to estimate how long this might be. However, the operating profiles shown earlier for the period from June, 2005 to June, 2006 indicate periods of little or no operation of Unit 5. Therefore, it appears that the tie-in could be accomplished with no serious downtime.

Other Environmental Issues

Retrofit to a closed-cycle cooling system introduces some environmental issues which a once-through cooling system does not. These are increased air emissions from the stack and drift from the cooling tower.

Stack Emissions

In an earlier section it was noted that a closed-cycle retrofit decreases the unit net output because of heat rate penalties and the use of increased operating power. In this instance these together were estimated at from 7 to 12%. Therefore, the delivery of the same amount of electric power to the grid will require the burning of additional fuel at some location to make up that lost at Harbor. In the discussion of this issue in Chapter 7, it was pointed out that the effect of making up this shortfall was highly variable depending on how and where the replacement per was generated. Therefore, no attempt is made to asses the effect in quantitative terms beyond pointing out that reliable estimates of the shortfall to be expected from full load operation can be made.

Drift

It is assumed that any cooling tower would be equipped with state-of-the-art drift eliminators rated at about 0.0005% of circulating water flow. The following table estimates the amount of drift to be expected from such designs. In addition, as discussed earlier, Federal EPA and State regulations characterize all solid carried off in cooing tower drift as PM10. The cost of offsetting this amount, should it be necessary will vary considerably from site to site as will the severity of the regulatory constraints.

Table B-72
Harbor Unit 5 Drift Estimates

Flow	Drift[1]	Drift	PM10	PM10	Cap. Factor	PM10
gpm	gpm	lb/hr	lb/hr	tons/year[2]	%	tons/year[3]
56,400	0.28	141	7.05	30.9	**20.5**	**6.3**

1. At drift eliminator efficiency of 0.0005%
2. Assumes full load all year
3. At 2006 capacity factor

General Conclusion

On balance, it is concluded that the nature of the likely problems and additional costs to be encountered at Harbor would put the retrofit at this site in a “average” category. Based on the results from the Maulbetsch Consulting survey presented above, this would put the project cost in the range of $15 to 17 million.

B.8 Mandalay Power Station (Reliant)

Location

393 N. Harbor Boulevard
Oxnard, CA 93035
34° 12’ 24.49” N; 119° 15’ 01.58” W
Contact: Kerry Whelan, 713-488-8080

Figure B-61
Mandalay Power Station Boundaries and Neighborhood

Figure B-62
Mandalay Power Station Site View

Plant/Site Information

Unit 1: 215 MW
Unit 2: 215 MW

Table B-73
Mandalay Cooling System Operating Conditions

Unit	MW	Cooling Water flow		Steam flow	Heat duty	Tin	Tex	Range	Tcond	TTD	Backpressure
		gpm	cfs	lb/hr	Btu/hr	F	F	F	F	F	in Hga
1	215	88,000	196	1.132E+06	1.075E+09	63.0	87.4	24.4	94.4	7.0	~ 1.6
2	215	88,000	196	1.132E+06	1.075E+09	63.0	87.4	24.4	94.4	7.0	~ 1.6

Table B-74
Mandalay Capacity Factors

Unit	MW (net)	Capacity Factor (%)						
		2001	2002	2003	2004	2005	2006	Average
1	215	53.7%	25.2%	14.2%	15.5%	7.3%	7.8%	14%
2	215	54.2%	28.2%	18.1%	20.1%	11.2%	8.6%	17%

Table B-75
Mandalay Meteorological Data

Temperature	Max.	Average	Min.
Mandalay inlet temp., °F	74	63	54
Atmos. wet bulb, °F	72	56	28
Atmos. dry bulb, °F	100	63	30

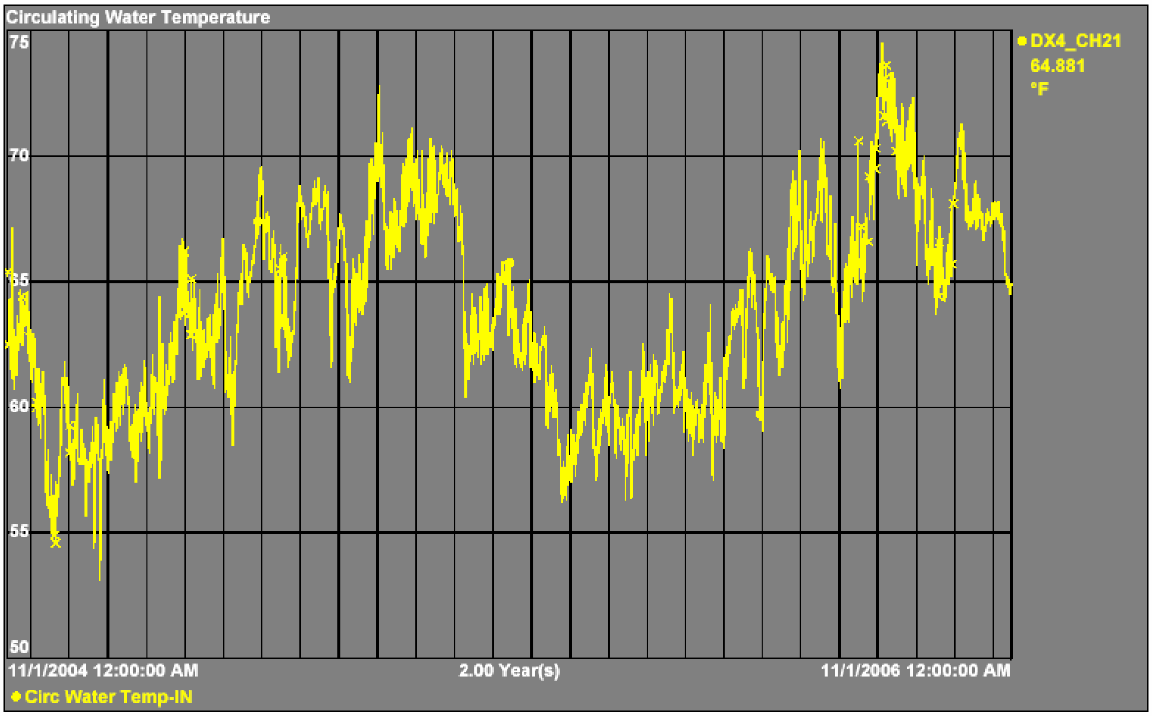


Figure B-63
Inlet Temperature Plot––2005–2006

Plant Operating Data

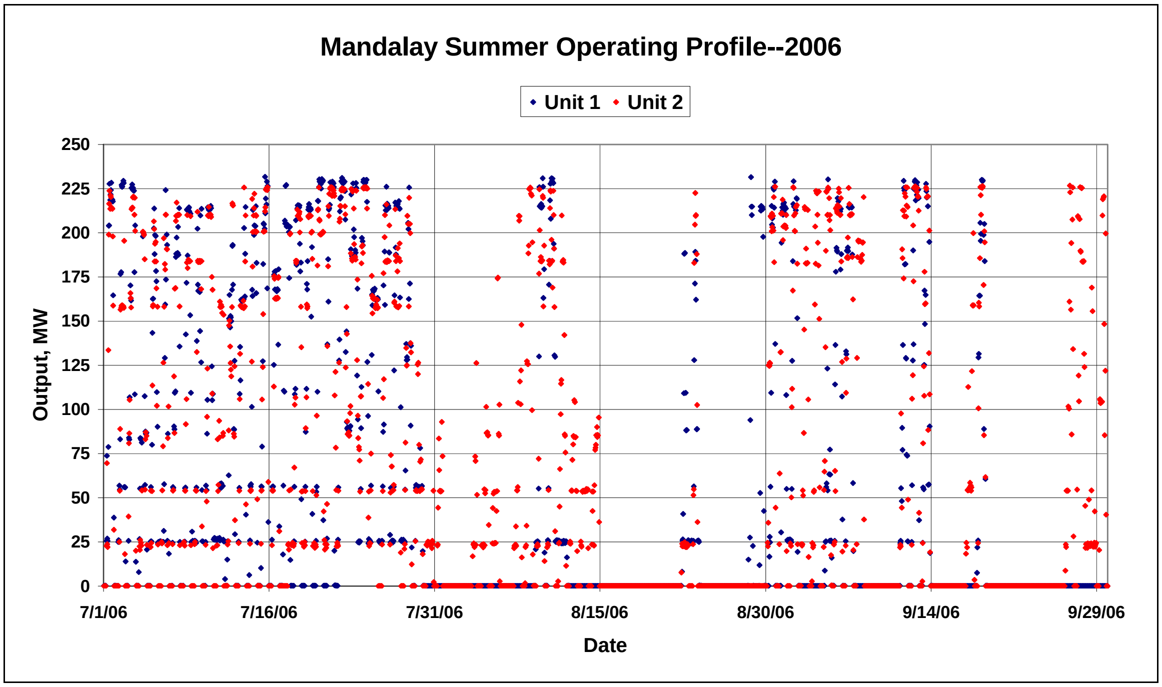


Figure B-64
Mandalay Summer Output––2006

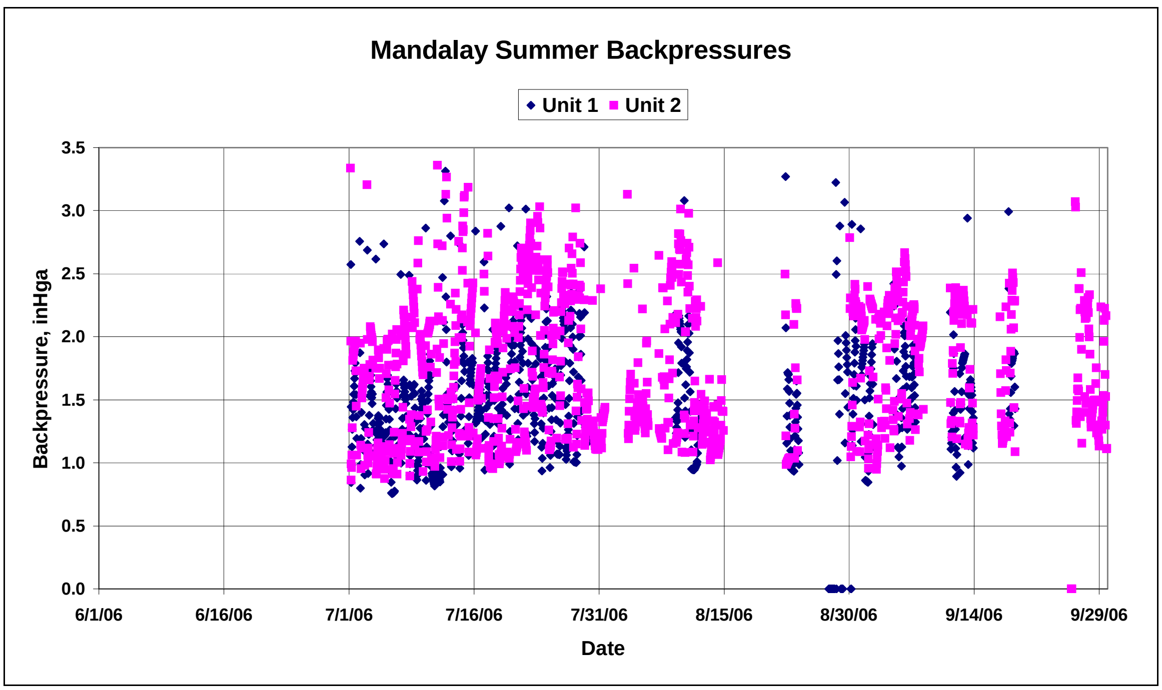


Figure B-65
Mandalay Summer Backpressure

Cooling Tower Assumptions/Design

Wet cooling system design specifications

- Tower type: mechanical draft, counterflow, FRP construction
- Make-up water source: Sea water; 35,000 ppm salinity
- Operating cycles of concentration: n = 1.5
- Evaporation rate: Units 1 and 2--- ~ 2.200 gpm each
- Make-up rate (@ n = 1.5): Units 1 and 2--- ~ 6,600 gpm each
- Blowdown (@ n = 1.5): Units 1 and 2--- ~ 4,400 gpm each

Tower design values are for the circulating water flow rates and the condenser specifications unchanged, an assumed tower approach of 10°F and a "1%" wet bulb temperature of 70°F.

This results in

- Ambient wet bulb: 70°F
- Range: 22.4°F
- Approach: 10°F
- TTD: 7.°F

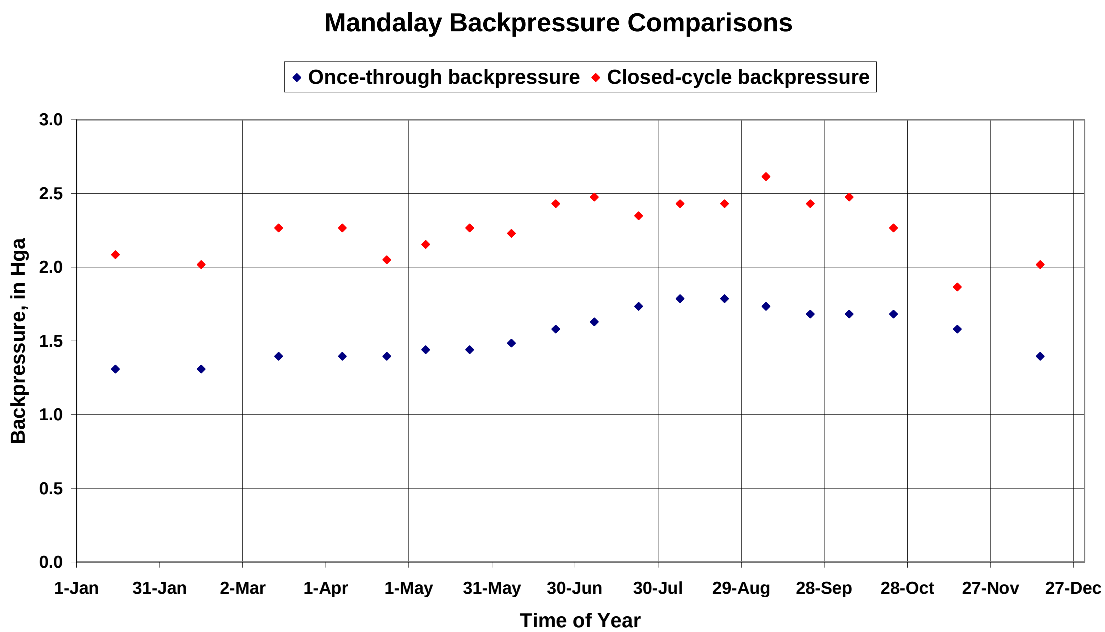
yielding a condensing temperature of

$$T_{cond} = 70 + 10 + 22.4 + 7. = 109.4°F$$

and a backpressure of 2.5 in Hga at full load on the hottest day.

Over the course of the year when the ambient wet bulb temperature would be lower, the backpressure would vary as indicated in the following figure. A comparison is given to the backpressure estimated with once-through cooling and indicates that the backpressure would normally be elevated by 1 to 1.5 in Hga.

Figure B-66
Backpressure Comparisons



Wet Retrofit Costs

Table B-76
S&W Cost Estimates

S&W Costs---escalated to 2007; x 1.07 for seawater					
Unit	Labor	Material	Equipment	Indirect	Total
1	$5,359,000	$3,122,000	$5,312,000	$8,000,000	$21,792,000
2	$5,359,000	$3,122,000	$5,312,000	$8,000,000	$21,792,000
Plant Total	$10,718,000	$6,244,000	$10,624,000	$16,000,000	$43,584,000

Table B-77
Maulbetsch Consulting Survey Estimates

Maulbetsch Consulting Survey; escalated to 2007 $; x 1.07 for salinity			
Unit	Easy	Average	Difficult
3	$12,589,000	$20,982,000	$32,427,000
4	$12,589,000	$20,982,000	$32,427,000
Plant Total	$25,178,000	$41,964,000	$64,854,000

Dry Cooling

Similar cost estimates can be made for a dry cooling retrofit. The basic assumption is that for plants with low capacity factors, they must be available to produce close to full load on the hottest days of the year when the system load is at its peak. Therefore,

- Direct dry cooling: forced, mechanical-draft air-cooled condenser
- Steam flow: ~ 1,132,000 lb/hr (Units 1 and 2 @ full load)
- Design dry bulb: 95°F (mid-way between 0.4% dry bulb and median of extreme highs)
- Design turbine exhaust pressure: 4.5 in Hga (based on assumption that turbines of this age and design trip at 5 in Hga and that the plant would not wish to reduce output on the hottest days)
- Corresponding condensing temperature: 130°F

Therefore, ACC design ITD ($T_{condensing}$ - $T_{design\ ambient}$) = 130°F – 95°F = **35°F**

Dry Cooling Retrofit Costs

AC costs can be roughly estimated from EPRI Report No. 1005358; "Comparison of Alternate Cooling Technologies for U.S. Power Plants", August, 2004.

Vendor information for a design of:

Steam flow:1,132,000 lb/hr (scaled from example case of 1,080,000 lb/hr)
ITD: 35°F
Price: 2002 $

Table B-78
Dry Cooling Retrofit Cost Estimates

Source/Basis	Equipment	Erection	Electrical	Duct Work	Indirect	Total	Cells
Vendor 1	$22,900,000	$9,800,000	$1,500,000	$150,000	$19,836,000	$54,186,000	50
Vendor 2	$24,000,000	$10,300,000	$1,200,000	$150,000	$20,590,000	$56,240,000	40
Vendor 3	$19,600,000	$9,600,000	$1,200,000	$150,000	$17,632,000	$48,182,000	40
Average	$22,167,000	$9,900,000	$1,300,000	$150,000	$19,353,000	$52,869,000	45
Scaled to 2007 $	$29,664,000	$11,791,000	$1,740,000	$201,000	$25,053,000	$68,448,000	
Including indirects	$46,869,000	$18,630,000	$2,749,000	$318,000	$39,584,000	$108,148,000	

Effect on Plant Performance

A retrofitted cooling system of either the wet or dry type would have a deleterious effect on the plant net heat rate. This arises from two effects:

1. Considering only the wet system, the power requirements will be higher than the current pumping power requirements for the once-through system. This power is used for the additional circulating pumps and for the cooling tower fans and represents power that must be generated but cannot be sold.
2. The plant will operate at a higher backpressure and therefore a higher heat rate with closed cycle cooling. This effect will be much more pronounced for a dry system than for a wet system.

The additional power requirements are estimated as follows:

Pumping power: As noted in Section 4.1.3, the existing circulating water system will discharge into a sump from which a second set of pumps will draw the water and discharge it to the top of the cooling tower. The circulating water flow rate must be pumped through an additional head rise. This will be estimated at 40 feet to account for the lift out of the sump, the rise to the hot water distribution deck on the top of the tower and the head loss through the circulating water lines. A combined pump/motor efficiency of 75% is assumed. Each of these factors would be refined in a detailed analysis, but these are considered adequate to give a reasonable estimate of the effect of additional operating power on the plant. For the several units at Mandalay:

Table B-79
Mandalay Units: Retrofit Additional Pumping Power

Unit	Flow	Head	Eff	Power	Motor
	gpm	ft		kW	MW
1	88,000	40	0.75	662.8	0.88
2	88,000	40	0.75	662.8	0.88

Fan power: Similarly cooling tower fan power can be roughly estimated. It is assumed for retrofits on older, lower capacity factor units, the tower would be sized to “low first cost” design since the number of operating hours is low and power penalties are less severe. This is consistent with the assumptions made in the retrofit capital cost estimates. The number of cells will be estimated as one cell per 10,000 gpm of circulating water flow, the fan horsepower at 200 HP and a motor efficiency of 90%. For the Mandalay units this results in:

Table B-80
Mandalay Units: Retrofit Fan Power

Unit	Flow	Cells	Eff	Power	Motor
	gpm	n		hp	kW
1	88,000	9	0.9	1,800	1,492
2	88,000	9	0.9	1,800	1,492

This represents a combined, full-load operating power requirement of approximately 4.7 MW or approximately 1% of the plant power rating of 450 MW. The actual annual cost will obviously depend on the capacity factor, the number of hours on-line, and whether some fans are turned off when operating at part load. Also, the cooling system was sized for full load at acceptable backpressures at so-called “1%” ambient conditions, it would be well oversized for nearly the entire year. Therefore, the effect of requiring additional operating power for the pumps and fans coupled with operation at higher heat rate would be an increase in the fuel burned rather than a reduction in plant output.

Heat rate penalty: As seen in the earlier plot of comparative backpressure, the condensing pressure with closed-cycle wet cooling will run typically .5 to 1.0 in Hga higher than it would with once-through ocean cooling and increases to about 2.5 in Hga on the hottest days. The effect is less at part load. No information is available to estimate the effect on heat rate resulting from the increased backpressure. However, information from comparable units suggest an increase of at least 0.25% for each 0.1 in Hga increase in backpressure above design might be reasonable. The comparative plot shown earlier suggests that closed-cycle cooling will result in increased backpressure throughout the year ranging from .5 to 1. in Hga with a corresponding heat rate penalty of 1.25 to 2.5%. In the absence of other information, it is assumed to be applicable to the Mandalay units as well resulting in a heat rate penalty at full load of 1.25 to 2.5.% for the units at the plant. It should be noted that some estimates on other individual units of similar size and age have been much higher, up to a heat rate increase of as much as 1,000 Btu/kWh for a backpressure increase of 1.5 to 2.5 in Hga.

Capacity Limits

The increased back pressure will likely results in an output restriction at the hottest day. The magnitude of the shortfall will depend on the operating philosophy. If the firing rate is held constant, a 1% heat rate penalty would correspond to roughly a 1% reduction in output. If the design of the units permits, this could presumably be compensated for with overfiring, but the heat rate penalty and hence the fuel cost, would increase even further.

This would appear to be a minor effect on output. If, however, it were to be decided that operation at a backpressure of 3.5 in Hga constituted an unacceptable maintenance risk to the turbine, then the firing rate would need to be reduced to hold whatever backpressure was consider acceptable. Information to estimate what the shortfall would be in that case is not available but presumably could be estimated by plant staff based on the information given above.

Maintenance Costs

Commonly used factors for maintenance (labor, materials, chemicals, etc.) for wet cooling systems range from 2. to 3. % of the system capital costs.

For wet systems, the important costs are for water treatment, biofouling control and keeping the basin clean. Using salt water and having salt drift around the plant would require rust control, extra painting, etc. Using the high end of typical factors, assume 3. to 3.5% of the capital cost of the tower. It is unclear how Reliant would allocate these costs between operation and maintenance, but an estimate of 3% of the “average” capital costs for all units of $42 million could amount to approximately $1,250,000 per year.

Additional Cost Considerations

Although the S&W costs are pretty close to the Maulbetsch Consulting survey’s “Average” difficulty estimate, neither of those estimates can account for any site-specific difficulties which might be encountered at the Mandalay site. Those items that could cause a retrofit at this site to be in a different, either “High” or “Easy” category include:

- Difficulty in locating the tower
- Unusual site preparation costs
- Significant interferences to the cost of installation of the circulating water lines
- The need for cooling tower plume abatement
- Stringent noise control
- The use of an alternate make-up water

Location of Tower/Unusual Site Preparation Costs/Interferences

It appears that space would be available to the north of the plant in what looks like a laydown or drying area. (See site photo at beginning of write-up).

No information is available regarding the suitability of these sites, but a number of items would need to be considered:

i. Other current uses for the area which would not be possible to relocate.
ii. Unstable soil conditions requiring significant foundation work such as deep pilings to stabilize the towers. This is likely given the location of the plant.
iii. Drift deposition from salt water towers.
iv. Underground infrastructure which would make the installation of underground circulating water lines difficult and costly.
v. Remoteness of current intake bays from towers north of the plant and difficulty in tying into the existing circulating water system.
vi. Potential neighborhood objections to visible plumes, corrosive drift and noise.
vii. The need for PM10 offsets for expected drift from seawater towers.

Plume Abatement

Based on the view in the aerial photo of the neighboring area, it appears that a visible plume would not be a serious issue at this site with the possible exception of safety concerns related to the road running east of the site. It is unlikely that a plume abatement tower would be required. If it were, however, a plume abatement tower would increase both the capital cost of the tower itself by a factor of perhaps 2. to 2.5 and the additional pumping power by an additional 30 to 50% due to the greater height to which the hot water must be pumped.

Aesthetics

In addition to any issues with a visual plume, the simple appearance of a cooling tower is sometimes considered an aesthetic affront. In this instance, it does not appear that this would present a problem.

Noise Control

Noise from wet cooling towers comes both from the fans and from the water cascading through the fill. Fan noise can be diminished by fan design or the reduction in air velocity which sometime requires the use of bigger, or more, cells. The water noise is more difficult to reduce and usually requires the construction of sound barriers around the cooling tower. As in the case of the plume abatement question, the aerial photo of the plant and the neighboring area makes it appear that cooling tower noise should not be a serious constraint. In case that it is, the capital cost of the tower itself cost might increase from 20 to 40%.

Alternate Sources of Make-Up Water

The use of seawater make-up can introduce intractable problems regarding drift and related maintenance considerations. (See later discussion of drift and PM10.) An alternative can be to purchase reclaimed water from nearby municipal water treatment facilities. There do not appear to be any nearby sources of alternate cooling water, but no information is available on the subject.

Shutdown Period

There is often concern over the period of post plant availability during the retrofit construction period. In this instance, it appears that the major part of the construction could be done while the plant is on-line, with shutdown required only for the final tie-in of the circulating water lines to the existing water circuit. There is no information available to estimate how long this might be. However, the operating profiles shown earlier indicate few periods of no operation in the summertime. No information is available for the rest of the year, If, however, there are periods during the rest of the year when there are frequent periods of no or limited operation, the tie-in could be accomplished during those periods with no serious downtime.

Other Environmental Issues

Retrofit to a closed-cycle cooling system introduces some environmental issues which a once-through cooling system does not. These are increased air emissions from the stack and drift from the cooling tower.

Stack Emissions

In an earlier section it was noted that a closed-cycle retrofit increase the unit net output because of heat rate penalties and the use of increased operating power. In this instance these together were estimated at from 1 to 2%. Therefore, the delivery of the same amount of electric power to the grid will require the burning of additional fuel at some location to make up that lost at Mandalay. Based on the unit heat rate information provided, this does not appear to be major effect in this case. Furthermore, in the discussion of this issue in Chapter 7, it was pointed out that the effect of making up this shortfall was highly variable depending on how and where the replacement per was generated. Therefore, no attempt is made to asses the effect in quantitative terms beyond pointing out that reliable estimates of the shortfall to be expected from full load operation can be made.

Drift

The neighboring areas appear to be agricultural and concern is sometimes expressed about the effect of saline drift on soil and crops. This has not proved to be an issue at other sites with salt water towers equipped with modern drift eliminators.

It is assumed that any cooling tower would be equipped with state-of-the-art drift eliminators rated at about 0.0005% of circulating water flow. The following table estimates the amount of drift to be expected from such designs. In addition, as discussed earlier, Federal EPA and State regulations characterize all solids carried off in cooling tower drift as PM10. The cost of offsetting these amount, should it be necessary, will vary considerably from site to site as will the severity of the regulatory constraints.

Table B-81
Mandalay Drift Estimates

	Flow	Drift[1]	Drift	PM10	PM10	Cap. Factor	PM10
Unit	**gpm**	**gpm**	**lb/hr**	**lb/hr**	**tons/year[2]**	**%**	**tons/year[3]**
1	**88,000**	0.44	220	11.00	48.2	**24.7**	**11.9**
2	**88,000**	0.44	220	11.00	48.2	**24.7**	**11.9**

1. At drift eliminator efficiency of 0.0005%
2. Assumes full load all year
3. At 2006 capacity factor

General Conclusion

On balance, it is concluded that the nature of the likely problems and additional costs to be encountered at Mandalay would put the retrofit at this site in an “easy” to “average” category. Based on the results from the Maulbetsch Consulting survey presented above, this would put the project cost in the range of $25 to 40 million. It should be noted that the capacity factors on both units for the past two years have been quite low and may not justify the cost of retrofit.

B.9 Morro Bay, LLC Morro Bay Power Plant (Dynegy)

Location

Morro Bay, CA 93442
35° 22' 20.67" N; 120° 51 24.54" W
Contact: Barb Irwin, 217/519-4035

Figure B-67
Morro Bay Steam Plant and Surroundings

Figure B-68
Morro Bay Steam Plant Site View

Plant/Site Information

Units 3 and 4: 300 MW

Table B-82
Morro Bay Cooling System Operating Conditions

Unit	MW	Cooling Water flow		Steam flow	Heat duty	Tin	Tex	Range	Tcond	TTD	Backpressure
		gpm	cfs	lb/hr	Btu/hr	F	F	F	F	F	in Hga
3	300	157,400	350	1.420E+06	1.349E+09	56.0	73.1	17.1	83.1	10.0	1.14
4	300	157,400	350	1.420E+06	1.349E+09	56.0	73.1	17.1	83.1	10.0	1.14

Table B-83
Morro Bay Capacity Factors

Unit	2001	2002	2003	2004	2005	2006	Average
3	67.6%	18.2%	5.3%	8.5%	6.3%	6.8%	18.8%
4	55.9%	36.2%	5.3%	4.1%	5.8%	5.6%	18.8%

Table B-84
Morro Bay Meteorological Data

Temperature	Max.	Average	Min.

Morro Bay inlet temp., °F	64	56	50
Atmos. wet bulb, °F	65	53	28
Atmos. dry bulb, °F	89	57	30

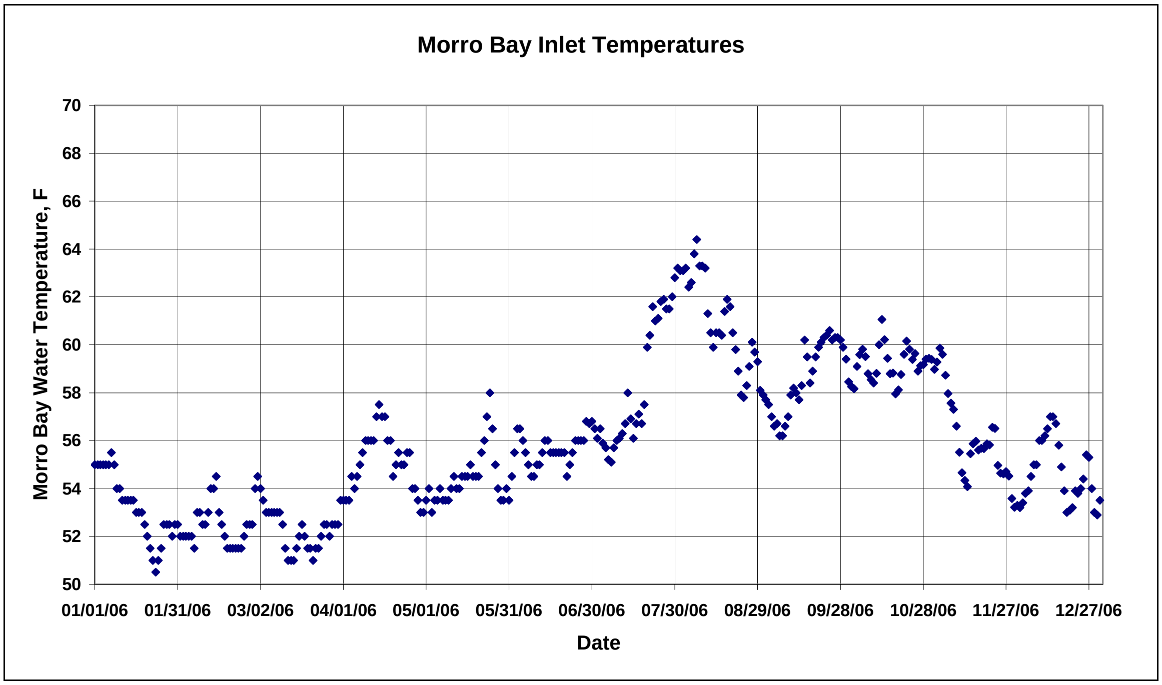


Figure B-69
Morro Bay Inlet Temperatures

Plant Operating Data

No information is available on plant output. The following figure estimates the condenser backpressure variation over the course of a year assuming once-through cooling and full load operation.

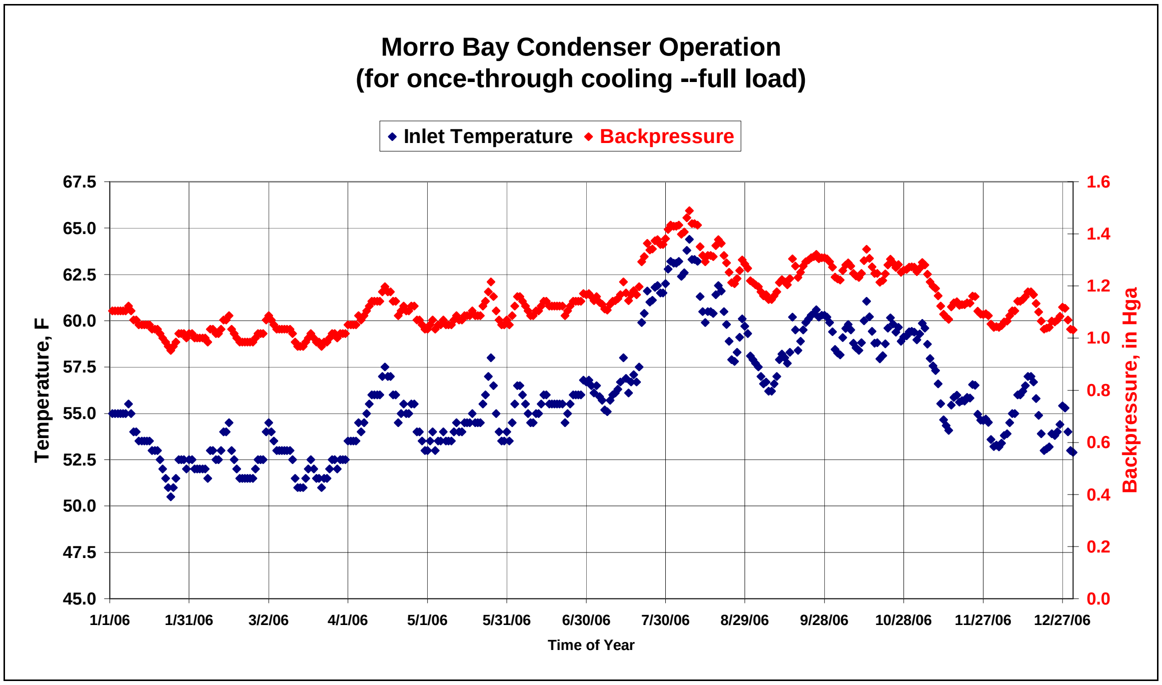


Figure B-70
Morro Bay Condenser Backpressure-Full Load

Cooling Tower Assumptions/Design

Wet cooling spec (example)

- Tower type: mechanical draft, counterflow, FRP construction
- Make-up water source: Sea water; 35,000 ppm salinity
- Operating cycles of concentration: n = 1.5
- Evaporation rate: Units 3 and 4--- ~ 3500 gpm each
- Make-up rate (@ n = 1.5): Units 3 and 4--- ~ 10,500 gpm each
- Blowdown (@ n = 1.5): Units 3 and 4--- ~ 7,000 gpm each

Tower design conditions are for all circulating water flows and condenser specifications unchanged, an assumed tower approach of 10°F and a peak wet bulb temperature of 65°F.

- Ambient wet bulb: 65°F
- Approach: 10°F
- Range: 17.1°F
- TTD: 10°F

Resulting in a condensing temperature of 102.1°F and a corresponding backpressure of 2.05 in Hga. Over the course of the year when the ambient wet bulb temperature would be lower, the backpressure would vary as indicated in the following figure. A comparison is given to the backpressure estimated with once-through cooling and indicates that the backpressure would normally be elevated by 0.5 to 1. in Hga.

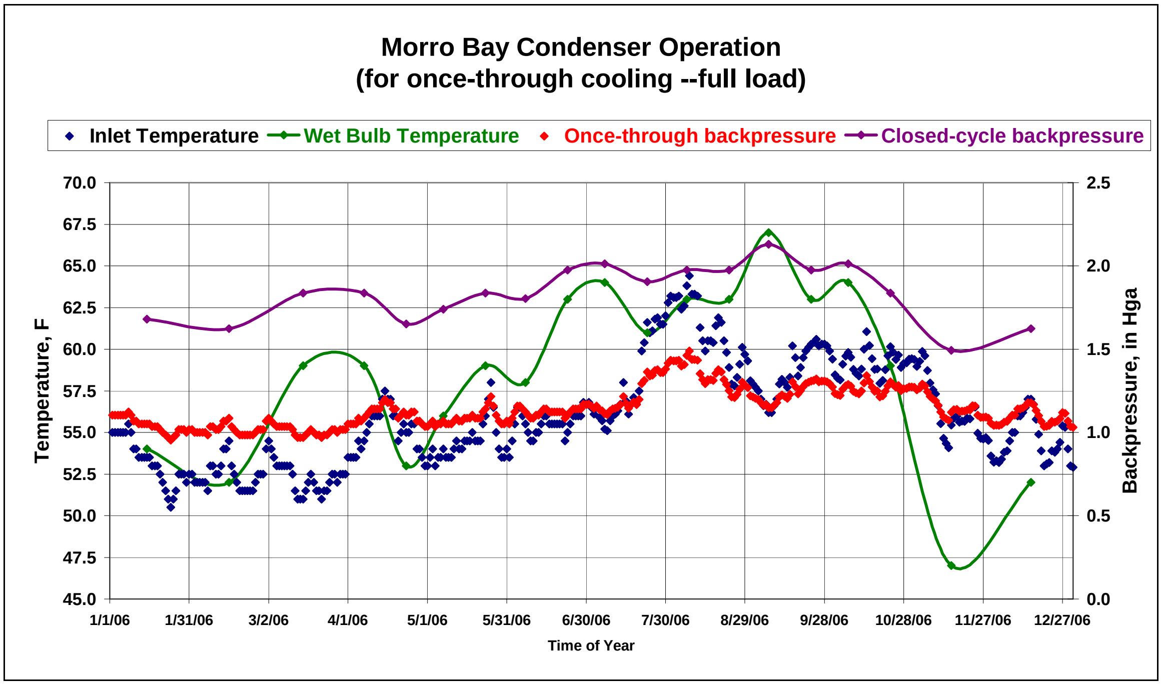


Figure B-71
Backpressure Comparisons

Wet Retrofit Costs

Table B-85
S&W Cost Estimates

S&W Costs---escalated to 2007; x 1.07 for seawater					
Unit	Labor	Material	Equipment	Indirect	Total
3	$10,333,000	$6,028,000	$10,238,000	$15,427,000	$42,027,000
4	$10,333,000	$6,028,000	$10,238,000	$15,427,000	$42,027,000
Plant Total	$20,666,000	$12,056,000	$20,476,000	$30,854,000	$84,054,000

Table B-86
Maulbetsch Consulting Survey Costs

Maulbetsch Consulting Survey; escalated to 2007 $; x 1.07 for salinity			
Unit	Easy	Average	Difficult
3	$24,290,000	$40,483,000	$62,565,000
4	$24,290,000	$40,483,000	$62,565,000
Plant Total	$48,580,000	$80,966,000	$125,130,000

Dry Cooling

Similar cost estimates can be made for a dry cooling retrofit. The basic assumption is that for plants with low capacity factors, they must be available to produce close to full load on the hottest days of the year when the system load is at its peak.

- Direct dry cooling: forced, mechanical-draft air-cooled condenser
- Steam flow: ~ 1,420,000 lb/hr (full load)
- Design dry bulb: 95°F (mid-way between 0.4% dry bulb and median of extreme highs)
- Design turbine exhaust pressure: 4.5 in Hga (based on assumption that turbines of this age and design trip at 5 in Hga and that the plant would not wish to reduce output on the hottest days)
- Corresponding condensing temperature: 130°F

Therefore, ACC design ITD ($T_{condensing}$ - $T_{design\ ambient}$) = 130°F – 95°F = **35°F**

Dry Cooling Retrofit Costs

AC costs can be roughly estimated from EPRI Report No. 1005358; "Comparison of Alternate Cooling Technologies for U.S. Power Plants", August, 2004.

Vendor information for a design of:

Steam flow: 1,420,000 lb/hr (scaled from example case of 1,080,000 lb/hr)
ITD: 35°F
Price: 2002 $

Table B-87
Dry Cooling Retrofit Cost Estimates

Source/Basis	Equipment	Erection	Electrical	Duct Work	Indirect	Total	Cells
Vendor 1	$24,710,000	$10,574,000	$1,619,000	$162,000	$21,404,000	$58,468,000	50
Vendor 2	$25,897,000	$11,114,000	$1,295,000	$162,000	$22,217,000	$60,684,000	40
Vendor 3	$21,149,000	$10,359,000	$1,295,000	$162,000	$19,025,000	$51,990,000	40
Average	$23,919,000	$10,682,000	$1,403,000	$162,000	$20,882,000	$57,047,000	45
Scaled to 2007 $	$32,008,000	$12,723,000	$1,878,000	$217,000	$27,033,000	$73,857,000	
Including indirects	$50,573,000	$20,102,000	$2,966,000	$343,000	$42,712,000	$116,694,000	

Effect on Plant Performance

A retrofitted cooling system of either the wet or dry type would have a deleterious effect on the plant net heat rate. This arises from two effects:

1. Considering only the wet system, the power requirements will be higher than the current pumping power requirements for the once-through system. This power is used for the additional circulating pumps and for the cooling tower fans and represents power that must be generated but cannot be sold.
2. The plant will operate at a higher backpressure and therefore a higher heat rate with closed cycle cooling. This effect will be much more pronounced for a dry system than for a wet system.

The additional power requirements are estimated as follows:

Pumping power: As noted in Section 4.1.3, the existing circulating water system will discharge into a sump from which a second set of pumps will draw the water and discharge it to the top of the cooling tower. The circulating water flow rate must be pumped through an additional head rise. This will be estimated at 40 feet to account for the lift out of the sump, the rise to the hot water distribution deck on the top of the tower and the head loss through the circulating water lines. A combined pump/motor efficiency of 75% is assumed. Each of these factors would be refined in a detailed analysis, but these are considered adequate to give a reasonable estimate of the effect of additional operating power on the plant. For the two units at Morro Bay:

Table B-88
Morro Bay Units: Retrofit Additional Pumping Power

Unit	Flow	Head	Eff	Power	Motor
	gpm	ft		kW	MW
3	157,400	40	0.75	1185.6	1.58
4	157,400	40	0.75	1185.6	1.58

Fan power: Similarly cooling tower fan power can be roughly estimated. It is assumed for retrofits on older, lower capacity factor units, the tower would be sized to “low first cost” design since the number of operating hours is low and power penalties are less severe. This is consistent with the assumptions made in the retrofit capital cost estimates. The number of cells will be estimated as one cell per 10,000 gpm of circulating water flow, the fan horsepower at 200 HP and a motor efficiency of 90%. For the Morro Bay units this results in:

Table B-89
Morro Bay Units: Retrofit Fan Power

Unit	Flow	Cells	Eff	Power	Motor
	gpm	n		hp	kW
3	157,400	16	0.9	3,200	2,652
4	157,400	16	0.9	3,200	2,652

This represents a combined, full-load operating power requirement of approximately 8.4 MW or approximately 1.4% of the plant power rating of 600 MW. The actual annual cost will obviously depend on the capacity factor, the number of hours on-line, and whether some fans are turned off when operating at part load. Also, the cooling system was sized for full load at acceptable backpressures at so-called “1%” ambient conditions, it would be well oversized for nearly the entire year. Therefore, the effect of requiring additional operating power for the pumps and fans coupled with operation at higher heat rate would be an increase in the fuel burned rather than a reduction in plant output.

Heat rate penalty: As seen in the earlier plot of comparative backpressures, the condensing pressure with closed-cycle wet cooling will run typically 0.5 to 1.0 in Hga higher than it would with once-through ocean cooling and increases to about 2.05 in Hga on the hottest days. The effect is less at part load. No information is available to estimate the effect on heat rate resulting from the increased backpressure. However, information from comparable units suggest an increase of at least 0.25% for each 0.1 in Hga increase in backpressure above design might be reasonable. The comparative plot shown earlier suggests that closed cycle cooling will result in increased backpressure throughout the year ranging from 0.5 to 1. in Hga with a corresponding heat rate penalty of 1.25 to 2.5%. In the absence of other information, it is assumed to be applicable to the Morro Bay units as well resulting in a heat rate penalty at full load of 0.5 to 1.% for the units at the plant. It should be noted that some estimates on other individual units of similar size and age have been much higher, up to a heat rate increase of as much as 1,000 Btu/kWh for a backpressure increase of 1.5 to 2.5 in Hga..

Capacity Limits

The increased back pressure will likely results in an output restriction at the hottest day. The magnitude of the shortfall will depend on the operating philosophy. If the firing rate is held constant, a 1% heat rate penalty would correspond to roughly a 1% reduction in output which would appear to be a minor effect on output. If, however, it were to be decided that operation at a backpressure of over 2 in. Hga constituted an unacceptable maintenance risk to the turbine, then the firing rate would need to be reduced to hold whatever backpressure was consider acceptable. Information to estimate what the shortfall would be in that case is not available but presumably could be estimated by plant staff based on the information given above.

Maintenance Costs

Commonly used factors for maintenance (labor, materials, chemicals, etc.) for wet cooling systems range from 2. to 3. % of the system capital costs. For wet systems, the important costs are for water treatment, biofouling control and keeping the basin clean. Using salt water and having salt drift around the plant would require rust control, extra painting, etc. Using the high end of typical factors, assume 3. to 3.5% of the capital cost of the tower. It is unclear how Dynegy Morro Bay would allocate these costs between operation and maintenance, but an estimate of 3% of the “average” capital costs for all units of $80 million could amount to approximately $2,500,000 per year.

Additional Cost Considerations

Although the S&W costs are pretty close to the Maulbetsch Consulting survey’s “Average” difficulty estimate, neither of those estimates can account for any site-specific difficulties which might be encountered at the Morro Bay site. Those items that could cause a retrofit at this site to be in a different, either “High” or “Easy” category include:

- Difficulty in locating the tower
- Unusual site preparation costs
- Significant interferences to the cost of installation of the circulating water lines
- The need for cooling tower plume abatement
- Stringent noise control
- The use of an alternate make-up water

Location of Tower/Unusual Site Preparation Costs/Interferences

It appears that space would be available to the northwest of the plant. This may require that one or more of what appear to be unused fuel tanks and possibly two small structures be removed or relocated. (See site photo at beginning of write-up).

No information is available regarding the suitability of this site, but a number of items would need to be considered including:

i. The need to demolish, relocate and rebuild existing structures for some locations.

ii. Unstable soil conditions requiring significant foundation work such as deep pilings to stabilize the towers.

iii. Drift deposition from salt water towers.

iv. Underground infrastructure which would make the installation of underground circulating water lines difficult and costly.

v. Remoteness of current intake bays and difficulty in tying into the existing circulating water system.

vi. Possible neighborhood objections to visible plumes, corrosive drift and noise.

vii. The need for PM10 offsets for expected drift from seawater towers.

Plume Abatement

Based on the view in the aerial photo of the neighboring area, it appears that a visible plume might be an issue at this site primarily from an aesthetic viewpoint. It is reasonable to assume that a plume abatement tower would be required. Plume abatement towers have an air-cooled section on top of the wet tower. The hot water is pumped to the top of the tower, passes down through the dry section and then discharged onto the hot water distribution deck of the wet section. The air passing across the finned tubes of the dry section mixes with the wet plume coming off the wet section and keeps it from becoming saturated and condensing in the cold atmosphere. The need for a plume abatement tower would increase both the capital cost of the tower itself by a factor of perhaps 2. to 2.5 and the additional pumping power by an additional 30 to 50% due to the greater height to which the hot water must be pumped.

Aesthetics

In addition to any issues with a visual plume, the simple appearance of a cooling tower is sometimes considered an aesthetic affront. In this instance, even though the towers would be visible to neighbors, considering the number, size and bulk of the plant buildings already present, it does not appear that this would present a major problem.

Noise Control

Noise from wet cooling towers comes both from the fans and from the water cascading through the fill. Fan noise can be diminished by fan design or the reduction in air velocity which sometime requires the use of bigger, or more, cells. The water noise is more difficult to reduce and usually requires the construction of sound barriers around the cooling tower. As in the case of the plume abatement question, the aerial photo of the plant and the neighboring area makes it appear that cooling tower noise might be an issue, although there is no information available with which to assess the question. In case that it is, the capital cost of the tower itself cost might increase from 20 to 40%.

Alternate Sources of Make-Up Water

The use of seawater make-up can introduce intractable problems regarding drift and related maintenance considerations. (See later discussion of drift and PM10.) An alternative can be to purchase reclaimed water from nearby municipal water treatment facilities. No information is available to evaluate this alternative.

If the use of reclaimed water for wet cooling tower makeup were to be considered, the distance of sources from the plant, the cost of installing delivery and return pipelines to the remote sources and the time required to obtain permits must be factored into any estimate of the cost.

Shutdown Period

There is often concern over the period of post plant availability during the retrofit construction period. In this instance, it appears that the major part of the construction could be done while the plant is on-line, with shutdown required only for the final tie-in of the circulating water lines to the existing water circuit. There is no information available to estimate how long this might be. However, the very low capacity factors for the past few years would suggest that the tie-in could be accomplished with no serious downtime.

Other Environmental Issues

Retrofit to a closed-cycle cooling system introduces some environmental issues which a once-through cooling system does not. These are increased air emissions from the stack and drift from the cooling tower.

Stack Emissions

In an earlier section it was noted that a closed-cycle retrofit increase the unit net output because of heat rate penalties and the use of increased operating power. In this instance these together were estimated at from 1 to 2%. Therefore, the delivery of the same amount of electric power to the grid will require the burning of additional fuel at some location to make up that lost at Morro Bay. Based on the unit heat rate information provided, this does not appear to be major effect in this case. Furthermore, in the discussion of this issue in Chapter 7, it was pointed out that the effect of making up this shortfall was highly variable depending on how and where the replacement per was generated. Therefore, no attempt is made to asses the effect in quantitative terms beyond pointing out that reliable estimates of the shortfall to be expected from full load operation can be made.

Drift

It is assumed that any cooling tower would be equipped with state-of-the-art drift eliminators rated at about 0.0005% of circulating water flow. The following table estimates the amount of drift to be expected from such designs. In addition, as discussed earlier, Federal EPA and State regulations characterize all solids carried off in cooling tower drift as PM10. The cost of offsetting this amount, should it be necessary will vary considerably from site to site as will the severity of the regulatory constraints.

Table B-90
Morro Bay Drift Estimates

Unit	Flow gpm	Drift[1] gpm	Drift lb/hr	PM10 lb/hr	PM10 tons/year[2]	Cap. Factor %	PM10 tons/year[3]
3	**157,400**	0.79	393	19.67	86.1	**24.7**	**21.3**
4	**157,400**	0.79	393	19.67	86.1	**24.7**	**21.3**

1. At drift eliminator efficiency of 0.0005%
2. Assumes full load all year
3. At 2006 capacity factor

General Conclusion

On balance, it is concluded that the nature of the likely problems and additional costs to be encountered at Morro Bay would put the retrofit at this site in a “average” category. Based on the results from the Maulbetsch Consulting survey presented above, this would put the project cost in the range of $80 million. It should be noted that the capacity factors on both units have been below 10% for the past four years and may not justify the cost of retrofit.

B.10 Moss Landing, LLC Moss Landing Power Plant (Dynegy)

Location

Dolan Road
Moss Landing, CA 95039
36° 48’ 18.26” N; 121° 46’ 46.88” W
Contact: Barb Irwin, 217/519-4035

Figure B-72
Moss Landing Power Plant (MLPP) Boundary and Neighborhood

Figure B-73
MLPP Site View

Plant/Site Information

Unit 1: 510 MW (combined-cycle)
Unit 2: 510 MW (combined-cycle)
Unit 6: 754 MW (steam boiler)
Unit 7: 755 MW (steam boiler)

Table B-91
MLPP Cooling System Operating Conditions

Unit	MW	Cooling Water flow		Steam flow	Heat duty	Tin	Tex	Range	Tcond	TTD	Backpressure
		gpm	cfs	lb/hr	Btu/hr	F	F	F	F	F	in Hga
1	510	107,000	238	1.104E+06	1.049E+09	56.1	75.7	19.6	87.4	11.7	1.31
2	510	107,000	238	1.104E+06	1.049E+09	56.1	75.7	19.6	87.4	11.7	1.31
6	754	298,000	663	2.999E+06	2.849E+09	60	79.1	19.1	89.1	10.0	1.38
7	755	298,000	663	2.999E+06	2.849E+09	60	79.1	19.1	89.1	10.0	1.38

Table B-92
MLPP Capacity Factors

Unit-Level Capacity Factors								
Unit	**MW**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**Average**
CC1	510		29.7%	60.0%	50.2%	50.0%	56.7%	49.3%
CC2	510		26.0%	53.6%	58.9%	53.2%	56.6%	49.7%
6	754	57.2%	36.2%	9.0%	5.6%	3.8%	6.2%	19.7%
7	755	79.9%	27.1%	11.8%	12.0%	3.8%	10.8%	24.2%

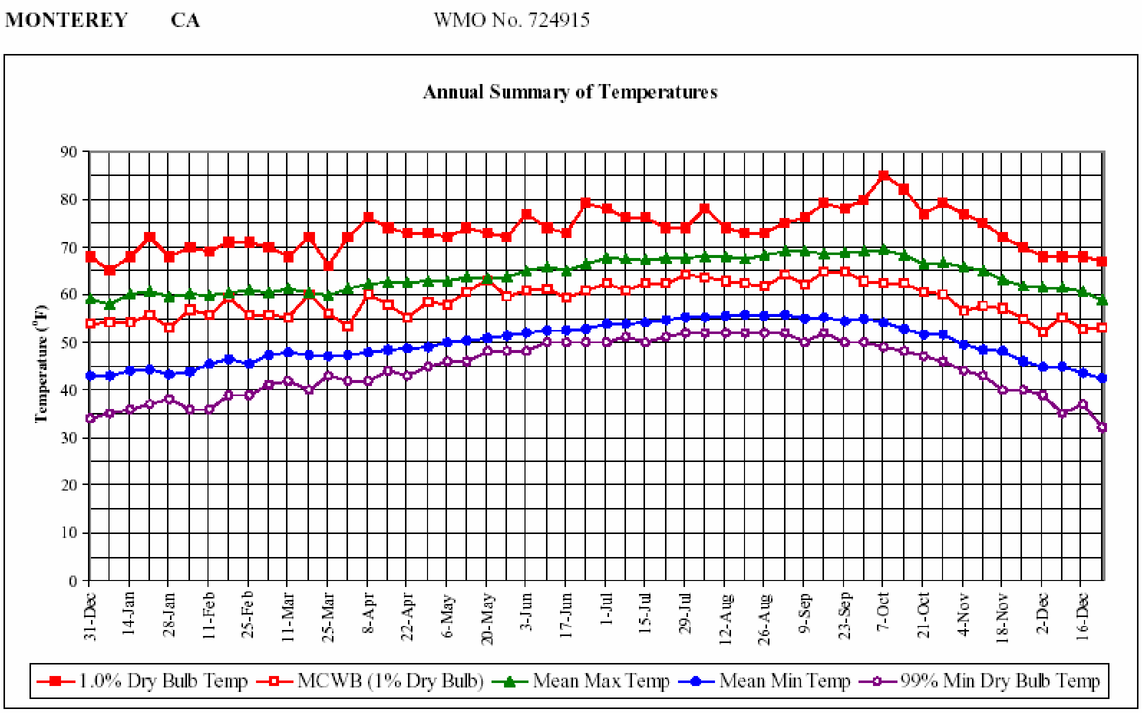


Figure B-74
Moss Landing Meteorological Data

Table Error! No text of specified style in document.**-1**
Moss Landing Meteorological Data

Temperature	Max.	Average	Min.
MLPP inlet temp., °F	63	56	51
Atmos. wet bulb, °F	68	60	35
Atmos. dry bulb, °F	90	61	38

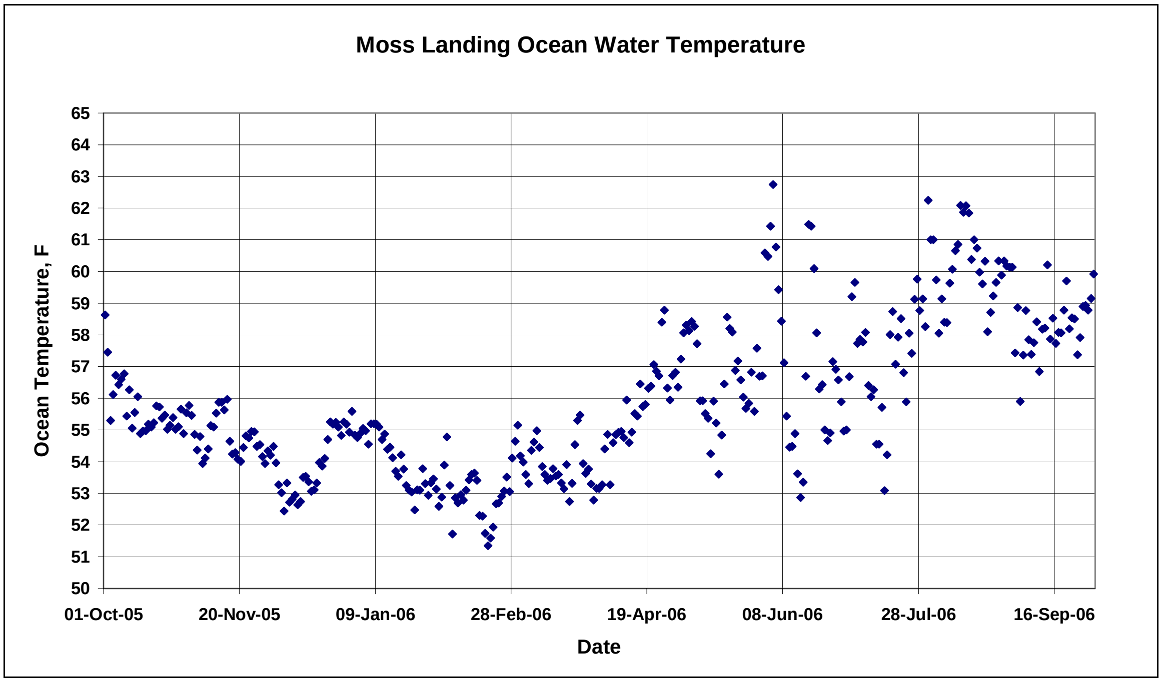


Figure B-75
MLPP Inlet Temperatures

Plant Operating Data

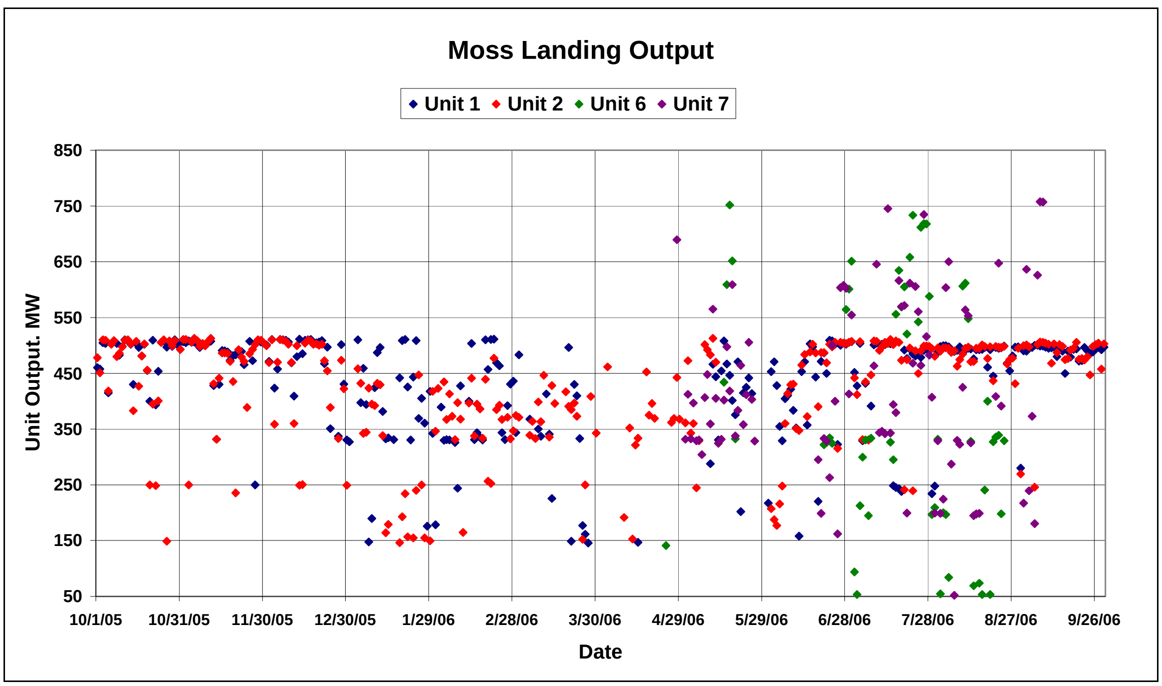


Figure B-76
MLPP Output Profile

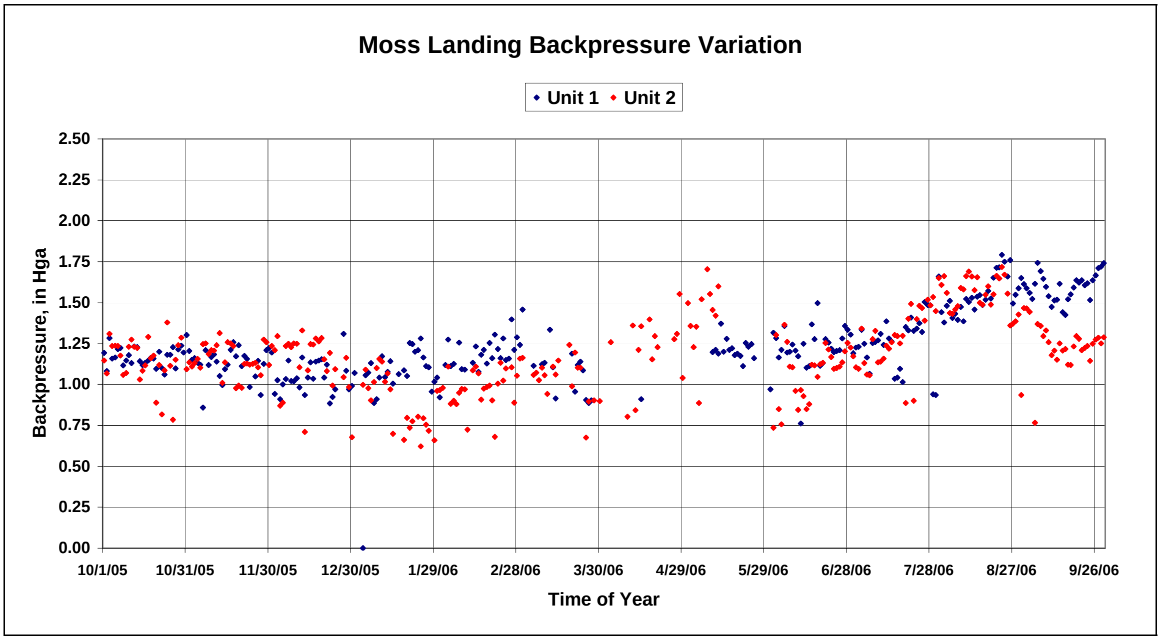


Figure B-77
MLPP Units 1 and 2 Backpressure Variation––Once-Through Cooling

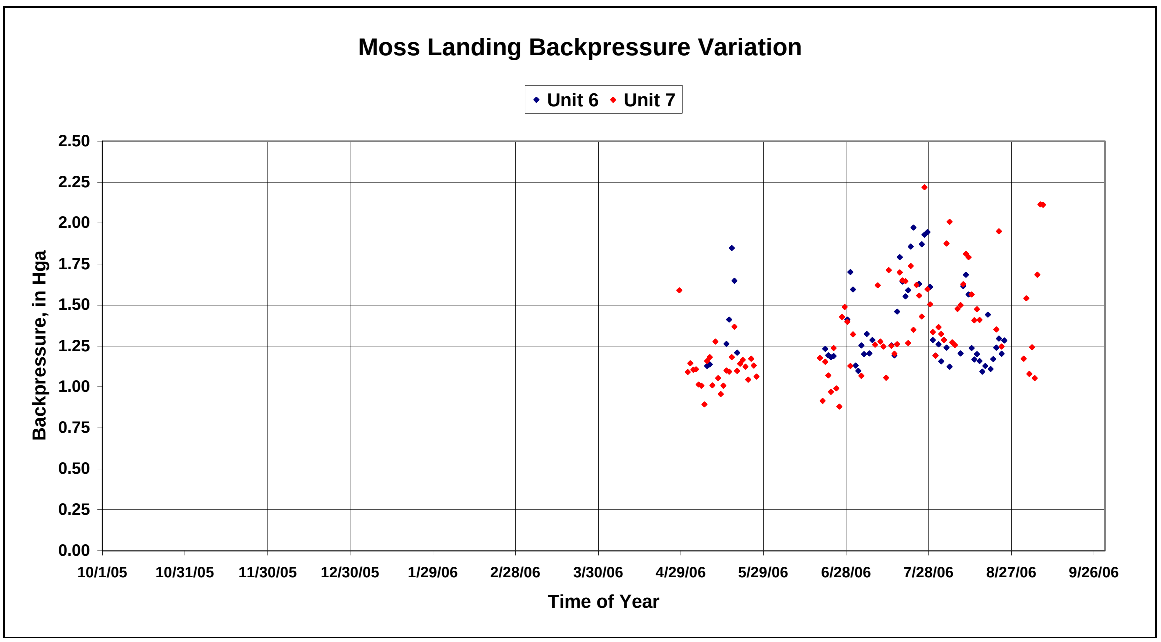


Figure B-78
MLPP Units 6 and 7 Backpressure Variation––Once-Through Cooling

Cooling Tower Assumptions/Design

Wet cooling system design specs for all units

- Tower type: mechanical draft, counterflow, FRP construction
- Make-up water source: Sea water; 35,000 ppm salinity
- Operating cycles of concentration: n = 1.5

Table B-94
Cooling Tower Water Balance Specifications

Unit	Evaporation	Make-up	Blowdown
	gpm	gpm	gpm
1	1,800	5,400	3,600
2	1,800	5,400	3,600
6	7,000	21,000	14,000
7	7,000	21,000	14,000

Tower design conditions are for all circulating water flows and condenser specifications unchanged, an assumed tower approach of 10°F and a peak wet bulb temperature of 68°F.

Table B-95
Cooling Tower Design Conditions for Full Load on Hot Day

Unit	Ambient Wet Bulb	Range	Approach	TTD	Tcond	Backpressure
	F	F	F	F	F	in Hga
1	68	19.9	10	7	104.9	~ 2.25
2	68	19.9	10	7	104.9	~ 2.25
6	68	26	10	7	111	~ 2.7
7	68	26	10	7	111	~ 2.7

Therefore, on the hottest day at full load, Units 1 and 2 would operate at a backpressure of approximately 2.25 in Hga; Units 6 and 7 at a backpressure of approximately 2.7 in Hga. Over the course of the year when the ambient wet bulb temperature would be lower, The backpressure would vary as indicated in the following figure. A comparison is given to the backpressure estimated with once-through cooling and indicates that the backpressure would normally be elevated by 0.5 to 1. in Hga.

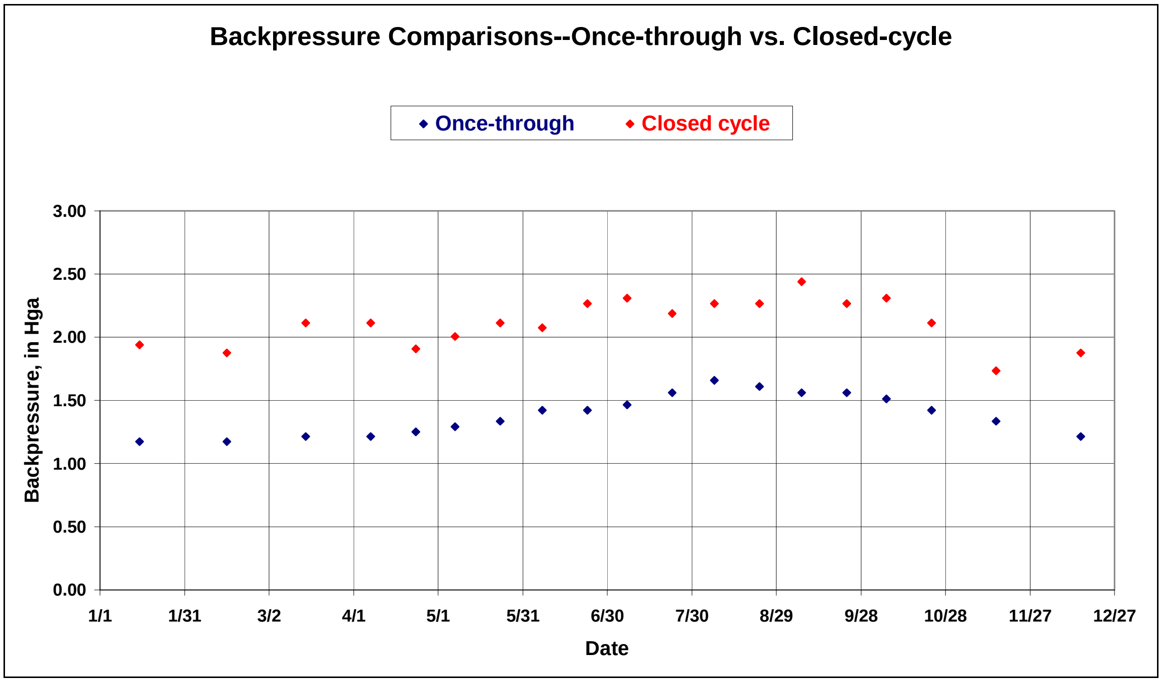


Figure B-79
Backpressure Comparisons

Wet Retrofit Costs

Table Error! No text of specified style in document.**-2**
S&W Cost Estimates

S&W Costs---escalated to 2007; x 1.07 for seawater					
Unit	**Labor**	**Material**	**Equipment**	**Indirect**	**Total**
1	$7,309,000	$4,089,000	$6,136,000	$11,249,000	$29,911,000
2	$7,309,000	$4,089,000	$6,136,000	$11,249,000	$29,911,000
6	$20,357,000	$11,388,000	$17,089,000	$31,328,000	$83,305,000
7	$20,357,000	$11,388,000	$17,089,000	$31,328,000	$83,305,000
Plant Total	$55,332,000	$30,954,000	$46,450,000	$85,154,000	$226,432,000

Table B-97
Maulbetsch Consulting Survey Estimates

JSM Survey; escalated to 2007 $; x 1.07 for salinity			
Unit	**Easy**	**Average**	**Difficult**
1	$17,655,000	$29,425,000	$45,475,000
2	$17,655,000	$29,425,000	$45,475,000
6	$49,170,000	$81,950,000	$126,650,000
7	$49,170,000	$81,950,000	$126,650,000
Plant	$133,650,000	$222,750,000	$344,250,000

Dry Cooling

Similar cost estimates can be made for a dry cooling retrofit. The basic assumption is that for plants with low capacity factors, they must be available to produce close to full load on the hottest days of the year when the system load is at its peak. Therefore,

- Direct dry cooling: forced, mechanical-draft air-cooled condenser

- Steam flow: Units 1 and 2: ~ 1.1 x 10^6 lb/hr
  Units 6 and 7: ~ 3.0 x 10^6 lb/hr
- Design dry bulb: 85°F (mid-way between 0.4% dry bulb and median of extreme highs)
- Design turbine exhaust pressure: 4.5 in Hga (based on assumption that turbines of this age and design trip at 5 in Hga and that the plant would not wish to reduce output on the hottest days)
- Corresponding condensing temperature: 130°F

Therefore, ACC design ITD ($T_{condensing}$ - $T_{design\ ambient}$) = 130°F – 85°F = **45°F**

Dry Cooling Retrofit Costs

AC costs can be roughly estimated from EPRI Report No. 1005358; "Comparison of Alternate Cooling Technologies for U.S. Power Plants", August, 2004.

Units 1 and 2:
Steam flow: 1,104,000 lb/hr
ITD: 45°F
Price: 2007 $

Units 6 and 7:
Steam flow: 2,999,000 lb/hr
ITD: 45°F
Price: 2007 $

Table B-98
Dry Cooling Retrofit Cost Estimates––Units 1 and 2

Source/Basis	Equipment	Erection	Electrical	Duct Work	Aux. cool	Total Direct	Indirects	Total	Cells
Vendor A (adjusted)	$14,578,000	$6,222,000	$933,000	$133,000	$1,600,000	$23,467,000	$13,611,000	$37,077,000	31
Vendor B	$16,000,000	$6,844,000	$800,000	$133,000	$1,778,000	$25,556,000	$14,822,000	$40,378,000	27
Vendor C	$13,244,000	$6,489,000	$800,000	$133,000	$1,511,000	$22,178,000	$12,863,000	$35,041,000	27
Average	$14,607,333	$6,518,333	$844,333	$133,000	$1,629,667	$23,733,667	$13,765,333	$37,498,667	28
2007$	$16,933,903	$7,556,535	$978,814	$154,183	$1,889,230	$27,513,824	$15,957,794	$43,471,232	

Table B-99
Dry Cooling Retrofit Cost Estimates––Units 6 and 7

Source/Basis	Equipment	Erection	Electrical	Duct Work	Aux. cool	Total Direct	Indirects	Total	Cells
Vendor A (adjusted)	$40,494,000	$17,284,000	$2,593,000	$370,000	$4,444,000	$65,185,000	$37,807,000	$102,993,000	86
Vendor B	$44,444,000	$19,012,000	$2,222,000	$370,000	$4,938,000	$70,988,000	$41,173,000	$112,160,000	74
Vendor C	$36,790,000	$18,025,000	$2,222,000	$370,000	$4,198,000	$61,605,000	$35,731,000	$97,336,000	74
Average	$40,576,000	$18,107,000	$2,345,667	$370,000	$4,526,667	$65,926,000	$38,237,000	$104,163,000	78
2007$	$47,038,705	$20,990,976	$2,719,271	$428,931	$5,247,647	$76,426,303	$44,327,163	$120,753,465	

The dry cooling costs estimates for Units 6 and 7 are presented for the sake of completeness only. There is no available space close enough to the turbines on these units to install an air-cooled condenser with a reasonable steam duct length.

Comparison with individual design

Retrofit cost estimates were developed for MLPP Units 1 and 2 by Duke Energy North America (DENA) in 2003 in the course of discussion s with the California Energy Commission. The estimates for mechanical-draft wet cooling, exclusive of their allowance for mitigation, was $46.6 million in 2003$. When escalated to 2007$ at 3% per year, the cost is $52.4 million which compares reasonably well with the S&W costs estimate of $59.8 million and the "average" survey cost of $58.8 million.

Costs were also developed by DENA for dry cooling for Units 1 and 2. The costs in 2003$ were $74.9 million which escalates to $84.4 million in 2007$. This corresponds quite closely to the estimate given above of $87 million.

Effect on Plant Performance

A retrofitted cooling system of either the wet or dry type would have a deleterious effect on the plant net heat rate. This arises from two effects:

1. Considering only the wet system, the power requirements will be higher than the current pumping power requirements for the once-through system. This power is used for the additional circulating pumps and for the cooling tower fans and represents power that must be generated but cannot be sold.
2. The plant will operate at a higher backpressure and therefore a higher heat rate with closed cycle cooling. This effect will be much more pronounced for a dry system than for a wet system.

The additional power requirements are estimated as follows:

Pumping power: The circulating water flow rate must be pumped through an additional head rise. This will be estimated at 40 feet to account for the lift out of the sump, the rise to the hot water distribution deck on the top of the tower and the head loss through the circulating water lines. A combined pump/motor efficiency of 75% is assumed. Each of these factors would be refined in a detailed analysis, but these are considered adequate to give a reasonable estimate of the effect of additional operating power on the plant. For the several units at MLPP:

Table B-100
MLPP Units: Retrofit Additional Pumping Power

Unit	Flow	Head	Eff	Power	Motor
	gpm	ft		kW	MW
1	107,000	40	0.75	806.0	1.07
2	107,000	40	0.75	806.0	1.07
6	298,000	40	0.75	2244.6	2.99
7	298,000	40	0.75	2244.6	2.99

Fan power: Similarly cooling tower fan power can be roughly estimated. It is assumed for retrofits on older, lower capacity factor units, the tower would be sized to "low first cost" design since the number of operating hours is low and power penalties are less severe. This is consistent with the assumptions made in the retrofit capital cost estimates. The number of cells will be estimated as one cell per 10,000 gpm of circulating water flow, the fan horsepower at 200 HP and a motor efficiency of 90%. For the MLPP units this results in:

Table B-101
MLPP Units: Retrofit Fan Power

Unit	Flow	Cells	Eff	Power	Motor
	gpm	n		hp	kW
1	107,000	11	0.9	2,200	1,824
2	107,000	11	0.9	2,200	1,824
6	298,000	30	0.9	6,000	4,973
7	298,000	30	0.9	6,000	4,973

This represents a combined, full-load operating power requirement of approximately 21.6 MW or approximately 0.9% of the plant power rating of 2,480 MW. The actual annual cost will obviously depend on the capacity factor, the number of hours on-line, and whether some fans are turned off when operating at part load. Also, the cooling system was sized for full load at acceptable backpressures at so-called "1%" ambient conditions, it would be well oversized for nearly the entire year. Therefore, the effect of requiring additional operating power for the pumps and fans coupled with operation at higher heat rate would be an increase in the fuel burned rather than a reduction in plant output.

Heat rate penalty: As seen in the earlier plot of comparative backpressure, the condensing pressure with closed-cycle wet cooling will run typically 0.5 to 1.0 in Hga higher than it would with once-through ocean cooling and increases to about 2.5 in Hga on the hottest days. The effect is less at part load. There is no directly applicable information available with which to determine the effect on unit heat rate. Information on turbines of similar age and type to those on Units 1 and 2 suggests a heat rate penalty of approximately 0.25% for each increase in backpressure of 0.1 in Hga above design. The comparative plot shown earlier suggests that closed cycle cooling will result in increased backpressure throughout the year ranging from 0.5 to 1. in Hga with a corresponding heat rate penalty of 0.5 to 1.%. This information was specifically for the steam portion of a combined cycle unit, but if, in the absence of other information, it is assumed to be applicable to the other units as well, it results in a heat rate penalty at full load of 0.5 to 1.% for the steam units at the plant.

Capacity Limits

The increased back pressure will likely results in an output restriction at the hottest day. The magnitude of the shortfall will depend on the operating philosophy. If the firing rate is held constant, a 1% heat rate penalty would correspond to roughly a 1% reduction in output. For the combined cycle units, this could presumably be compensated for with duct firing, but the heat rate penalty and hence the fuel cost, would increase even further.

Even for the steam units, it would appear to be a minor effect on output. If, however, it were to be decided that operation at a backpressure of 2.5 in Hga constituted an unacceptable maintenance risk to the turbine, then the firing rate would need to be reduced to hold whatever backpressure was considered acceptable. Information to estimate what the shortfall would be in that case is not available but presumably could be estimated by plant staff based on the information given above.

Maintenance Costs

Commonly used factors for maintenance (labor, materials, chemicals, etc.) for wet cooling systems range from 2. to 3. % of the system capital costs.

For wet systems, the important costs are for water treatment, biofouling control and keeping the basin clean. Using salt water and having salt drift around the plant would require rust control, extra painting, etc. Using the high end of typical factors, assume 3. to 3.5% of the capital cost of the tower. It is unclear how MLPP would allocate these costs between operation and maintenance, but an estimate of 3% of the “average” capital costs for all units of $75 million could amount to approximately $2,000,000 per year.

Capacity Factor Considerations

The remainder of the discussion will be limited to Units 1 and 2 on the basis that retrofit costs and penalties of the magnitude estimated above cannot be considered economically feasible for Units 6 and 7 with recent capacity factors averaging 7% for Unit 7 for the past two years and 6% for Unit 6 for the past four years.

Additional Cost Considerations

Although the S&W costs are pretty close to the Maulbetsch Consulting survey’s “Average” difficulty estimate, neither of those estimates can fully account for any site-specific difficulties which might be encountered at MLPP. Those items that could cause a retrofit at this site to be in a different, either “High” or “Easy” category include:

- Difficulty in locating the tower
- Unusual site preparation costs
- Significant interferences to the cost of installation of the circulating water lines
- The need for cooling tower plume abatement
- Stringent noise control
- The use of an alternate make-up water

Location of Tower/Unusual Site Preparation Costs/Interferences

Several alternate locations for the towers were considered. A base assumption was that the switchyards north of the power blocks would not be moved.

The preferred location from the point of available space is the open area behind to the east of Units 1 and 2. It does not appear that any existing structures would need to be demolished or relocated. Soil conditions at that location should be similar to those encountered during construction of the power blocks for Units 1 and 2.

The primary concerns with this location are the length of the circulating water lines and the possibility of saline drift effects on the 500 kV switchyard. As was discussed in some detail in Section 4, the general assumption in all the retrofit analyses was that the existing circulating water system would be maintained and a second circulating water system with lines and pumps would be installed to draw water from the existing condenser discharge bay (in some instances a new sump would have to be installed) and discharge back into the existing system's intake bay. This is done to avoid the need to reinforce the existing condenser and the existing circulating water lines to withstand increased pressure.

In this case, the discharge from the condensers is most easily accessed at the disengagement basin which is located far from the units down near Units 6 and 7. Similarly the intake bay is at the west end of the site. As a result the circulating water lines for the new cooling towers would be at least 2,000 feet long. The installation of over 4,000 feet of new circulating water line would likely be subject to the same numerous interferences that were encountered when the once-through cooling system was installed for Units 1 and 2 originally.

Plume Abatement

Based on the view in the aerial photo of the neighboring area, it is difficult to determine whether a visible plume would be a serious siting issue at MLPP. There do not appear to be residential areas close enough to be affected, but Highway 1 which passes directly in front of the site has been designated a Scenic Highway and Elkhorn Slough is a popular environmentally interesting area with many visitors. At a minimum, simulations of likely plume size and frequency would need to be conducted and the issue would certainly be a part of any siting procedures.

While it may not be that plume abatement towers would be required, if they were both the capital and operating cost would be higher. Plume abatement towers have an air-cooled section on top of the wet tower. The hot water is pumped to the top of the tower, passes down through the dry section and then discharged onto the hot water distribution deck of the wet section. The air passing across the finned tubes of the dry section mixes with the wet plume coming off the wet section and keeps it from becoming saturated and condensing in the cold atmosphere. The need for a plume abatement tower would increase both the capital cost of the tower itself by a factor of perhaps 2. to 2.5 and the additional pumping power by an additional 30 to 50% due to the greater height to which the hot water must be pumped.

Aesthetics

In addition to any issues with a visual plume, the simple appearance of a cooling tower is sometimes considered an aesthetic affront. The same considerations would apply here as were discussed above for the visible plume. The towers themselves would be relatively unobtrusive from Highway 1. However, they would be visible from Dolan Road and probably from some locations. Given the number, size and bulk of plant structures already present, it does not appear that this should present a major problem. However, the issue was thoroughly considered in the design phase of Units 1 and 2 and a compact design configuration was chosen on the basis of reducing visual impact.

Noise Control

Noise from wet cooling towers comes both from the fans and from the water cascading through the fill. Fan noise can be diminished by fan design or the reduction in air velocity which sometime requires the use of bigger, or more, cells. The water noise is more difficult to reduce and usually requires the construction of sound barriers around the cooling tower. The aerial photo of the plant and the neighboring area makes it appear that cooling tower noise should not be a serious constraint. In case that it is, the capital cost of the tower itself cost might increase from 20 to 40%.

Alternate Sources of Make-Up Water

The use of seawater make-up can introduce intractable problems regarding drift and related maintenance considerations. (See later discussion of drift and PM10.) An alternative can be to purchase reclaimed water from nearby municipal water treatment facilities. No information is available to evaluate this alternative but it does not appear that there are any source close enough to be considered.

Shutdown Period

There is often concern over the period of post plant availability during the retrofit construction period. In this instance, it appears that the major part of the construction could be done while the plant is on-line. It would appear that the major disruption to plant activities would be connected to the installation of the new recirculating water lines and the final tie-in of the circulating water lines to the existing water circuit. Since Units 1 and 2 have relatively high capacity factors, any loss of operating time would add substantially to the cost. There is no information available to estimate how long this might be.

Other Environmental Issues

Retrofit to a closed-cycle cooling system introduces some environmental issues which a once-through cooling system does not. These are increased air emissions from the stack and drift from the cooling tower.

Stack Emissions

In an earlier section it was noted that a closed-cycle retrofit increase the unit net output because of heat rate penalties and the use of increased operating power. In this instance these together were estimated at from 1 to 2%. Therefore, the delivery of the same amount of electric power to the grid will require the burning of additional fuel at some location to make up that lost at MLPP. Based on the unit heat rate information provided, this does not appear to be major effect in this case. Furthermore, in the discussion of this issue in Chapter 7, it was pointed out that the effect of making up this shortfall was highly variable depending on how and where the replacement per was generated. Therefore, no attempt is made to asses the effect in quantitative terms beyond pointing out that reliable estimates of the shortfall to be expected from full load operation can be made.

Drift

It is assumed that any cooling tower would be equipped with state-of-the-art drift eliminators rated at about 0.0005% of circulating water flow. The following table estimates the amount of drift to be expected from such designs. In addition, as discussed earlier, Federal EPA and State regulations characterize all solids carried off in cooling tower drift as PM10. The cost of offsetting this amount, should it be necessary will vary considerably from site to site as will the severity of the regulatory constraints. Information on this question for MLPP was considered in the DENA study in 2003.

Table B-102
MLPP Drift Estimates

Unit	Flow	Drift[1]	Drift	PM10	PM10	Cap. Factor	PM10
	gpm	gpm	lb/hr	lb/hr	tons/year[2]	%	tons/year[3]
1	**107,000**	0.54	267	13.37	58.6	**24.7**	**14.5**
2	**107,000**	0.54	267	13.37	58.6	**25.7**	**15.0**
6	**298,000**	1.49	745	37.24	163.1	**26.7**	**43.5**
7	**298,000**	1.49	745	37.24	163.1	**27.7**	**45.2**

1. At drift eliminator efficiency of 0.0005%
2. Assumes full load all year
3. At 2006 capacity factor

General Conclusion

On balance, it is concluded that the nature of the likely problems and additional costs to be encountered at MLPP would put the retrofit at this site in a “more than average” difficulty category even though the more site-specific estimate from DENA corresponds reasonably well to the “average” costs from the survey. Based on the results from the Maulbetsch Consulting survey presented above, this would put the project cost in the range of $80 to $90 million for Units 1 and 2 alone. If Units 6 and 7 were to be included, it would add $200 to $250 million to the cost which, for units with such low capacity factors, is uneconomical.

B.11 Ormond Beach Power Station (Reliant)

Location

6635 South Edison Drive
Oxnard, CA 95033
34° 07’ 45.25” N; 119° 10’ 07.77” W
Contact: Kerry Whelan, 713-488-8080

Figure B-80
Ormond Beach Power Station: Boundaries and Neighborhood

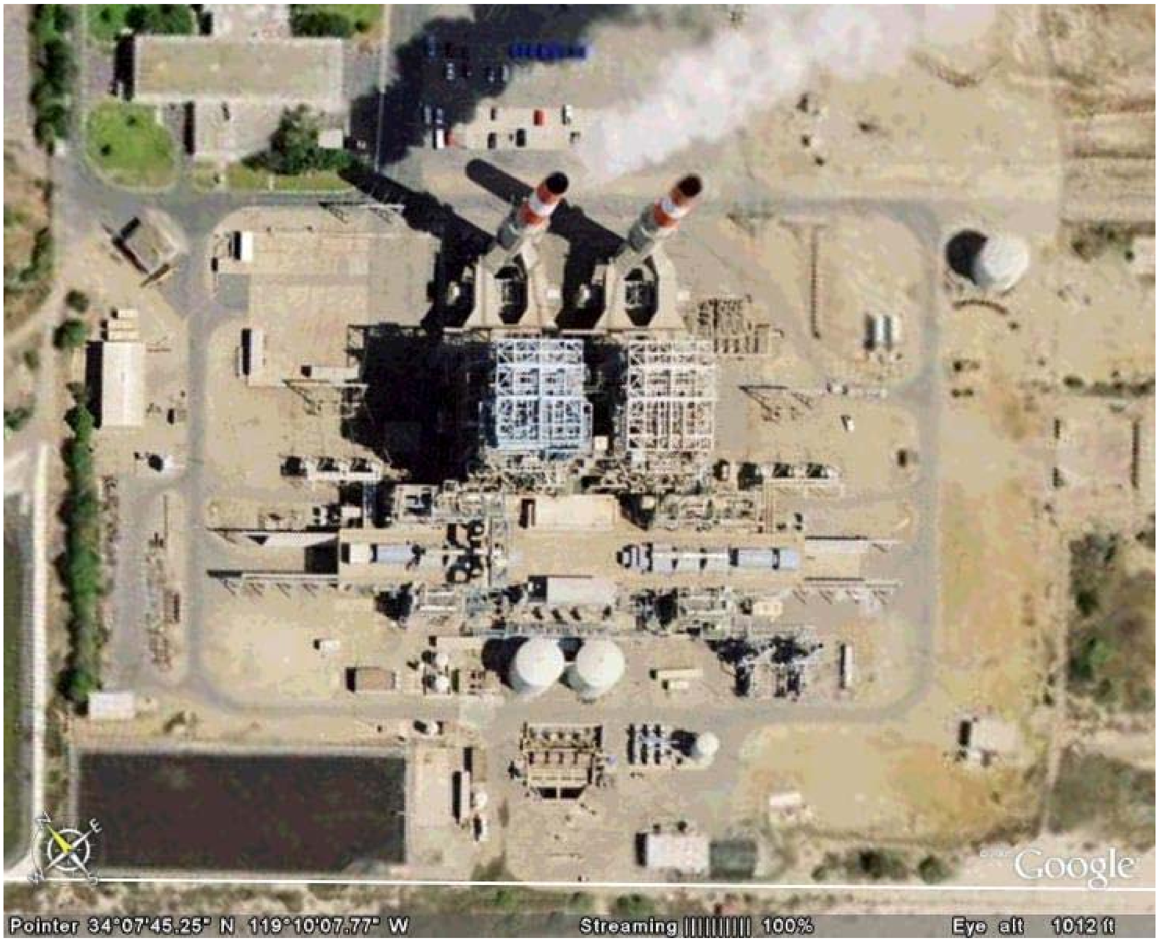


Figure B-81
Ormond Beach Power Station: Site View

Plant/Site Information

Units 1 and 2: 750 MW

Table B-103
Ormond Beach Cooling System Operating Conditions-Units 1 and 2 Identical

Unit	MW	Cooling Water Flow		Steam Flow	Heat duty	Tin	Tex	Range	Tcond	TTD	Backpressure
		gpm	cfs	lb/hr	Btu/hr	F	F	F	F	F	in Hga
1 & 2	750	227,000	505	3.272E+06							
LP		227,000	505	3.272E+06	1.824E+09	62.0	78.1	16.1	104.0	25.9	2.18
HP		227,001	505	3.272E+06	1.547E+09	78.1	91.7	13.6	111	19.3	2.67

Table B-104
Ormond Beach Capacity Factors

Unit	2001	2002	2003	2004	2005	2006	Average
1	46.5%	17.7%	11.2%	20.0%	2.0%	0.2%	16.3%
2	45.0%	17.9%	16.5%	14.2%	6.0%	6.5%	17.7%

Table B-105
Ormond Beach Meteorological Data

Temperature	Max.	Average	Min.
Ormond Beach inlet temp., °F	68	63	58
Atmos. wet bulb, °F	72	56	28
Atmos. dry bulb, °F	100	63	30

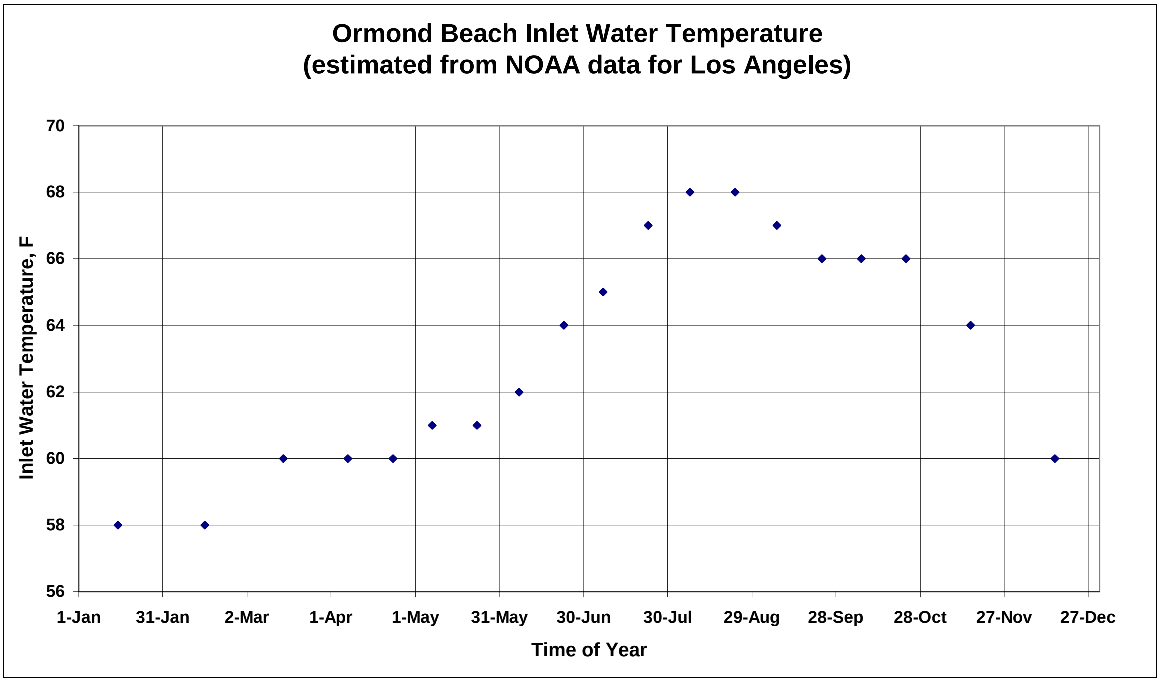


Figure B-82
Ocean Temperature Plot for Year

Plant Operating Data

No plant operating data are available. The following plot is an estimate of the backpressure variation during the year for full load operation based on the estimated inlet water temperature and condenser design specifications.

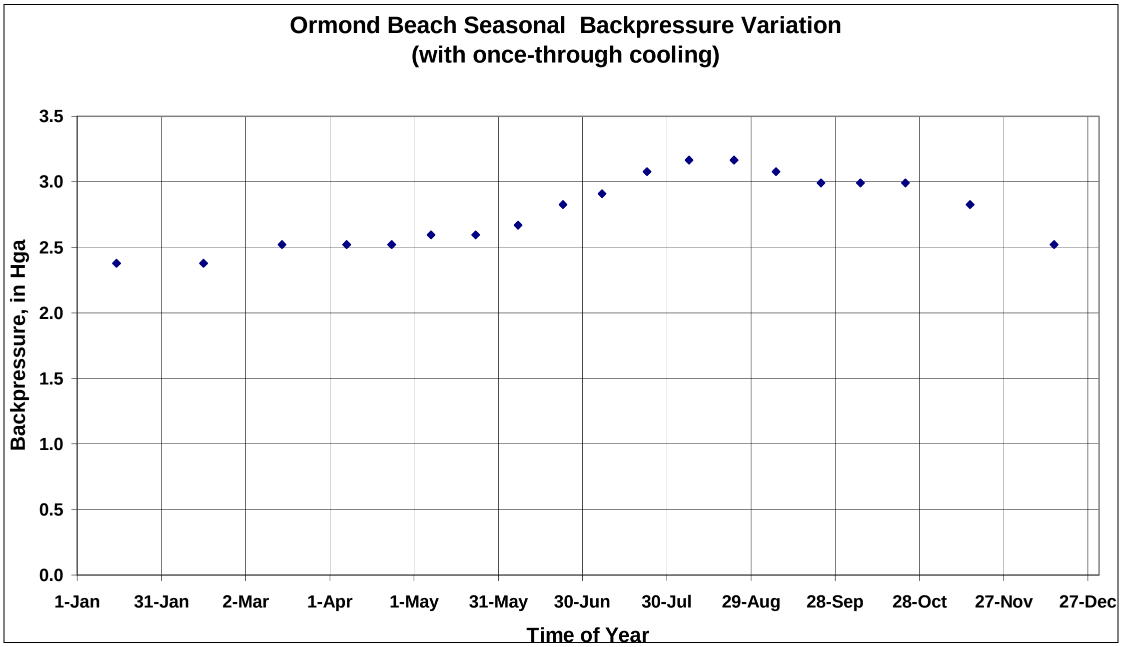


Figure B-83
Estimated Seasonal Backpressure Variation for Ormond Beach With Once-Through Cooling

Cooling Tower Assumptions/Design

Wet cooling system design specifications

- Tower type: mechanical draft, counterflow, FRP construction
- Make-up water source: Sea water; 35,000 ppm salinity
- Operating cycles of concentration: n = 1.5
- Evaporation rate: Units 1 and 2--- ~ 7,500 gpm each
- Make-up rate (@ n = 1.5): Units 1 and 2--- ~ 22,500 gpm each
- Blowdown (@ n = 1.5): Units 1 and 2--- ~ 15,000 gpm each

Tower design values are for the circulating water flow rates and the condenser specifications unchanged, an assumed tower approach of 10 ºF and a 1% wet bulb temperature of 70°F.

This results in

- Ambient wet bulb: 70°F
- Range: 29.7°F
- Approach: 10°F
- TTD: 19.3°F

yielding a condensing temperature of

$$T_{cond} = 70 + 10 + 29.7 + 19.3 = 129°F$$

and a backpressure of 4.4 in Hga at full load on the hottest day.

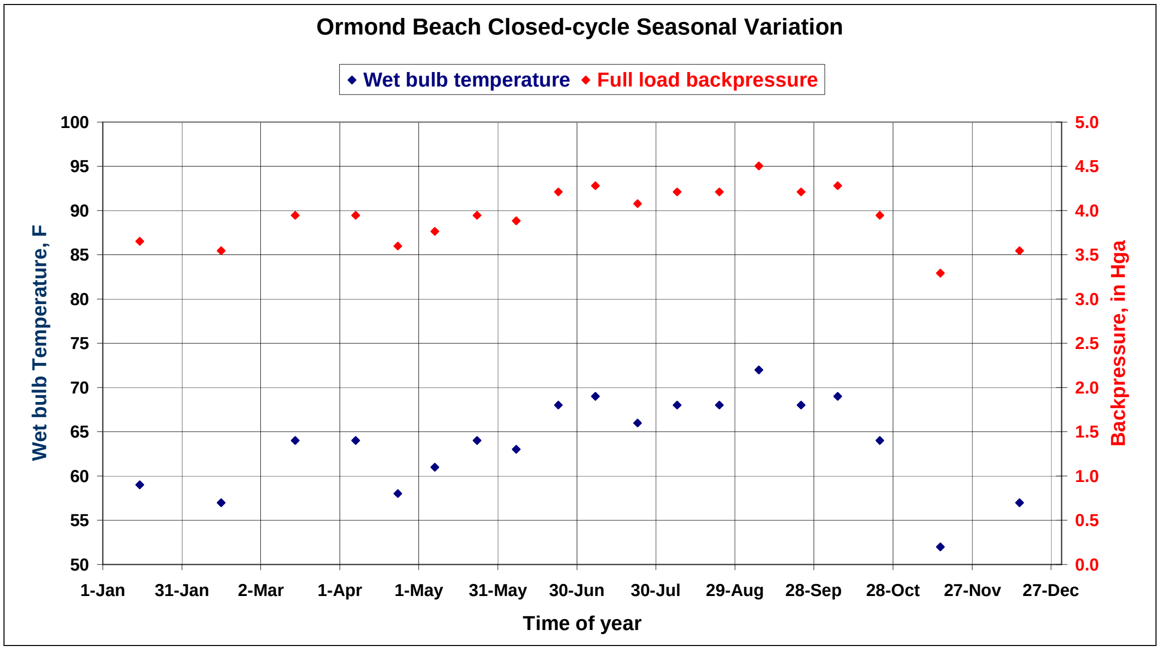


Figure B-84
Tower Design Specs (Full Load)

Therefore, on the hottest day at full load, all units would operate at a backpressure of approximately 4.5 in Hga. Over the course of the year when the ambient wet bulb temperature would be lower, The backpressure would vary as indicated in the following figure. A comparison is given to the backpressure estimated with once-through cooling and indicates that the backpressure would normally be elevated by 1. to 1.5 in Hga.

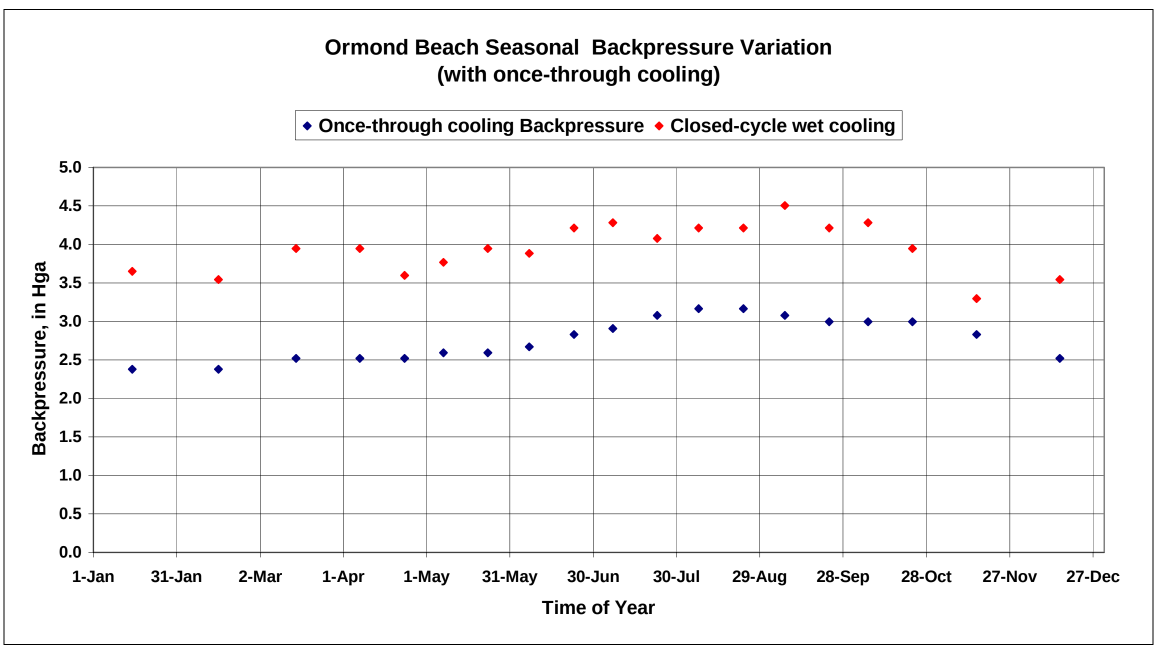


Figure B-85
Backpressure Comparisons

Wet Retrofit Costs

Table B-106
S&W Cost Estimates for Ormond Beach

S&W Costs---escalated to 2007; x 1.07 for seawater					
Unit	**Labor**	**Material**	**Equipment**	**Indirect**	**Total**
1	**$13,719,000**	**$9,164,000**	**$15,708,000**	**$22,383,000**	**$60,974,000**
2	**$13,719,000**	**$9,164,000**	**$15,708,000**	**$22,383,000**	**$60,974,000**
Plant Total	**$27,438,000**	**$18,328,000**	**$31,416,000**	**$44,766,000**	**$121,948,000**

Table B-107
Maulbetsch Consulting Survey Estimates for Ormond Beach

Maulbetsch Consulting Survey; escalated to 2007 $; x 1.07 for salinity			
Unit	**Easy**	**Average**	**Difficult**
1	**$39,249,000**	**$65,414,000**	**$101,095,000**
2	**$39,249,000**	**$65,414,000**	**$101,095,000**
Plant Total	**$78,498,000**	**$130,828,000**	**$202,190,000**

Dry Cooling

Similar cost estimates can be made for a dry cooling retrofit. The basic assumption is that for plants with low capacity factors, they must be available to produce close to full load on the hottest days of the year when the system load is at its peak.

- Direct dry cooling: forced, mechanical-draft air-cooled condenser
- Steam flow: ~ 3,270,000 lb/hr (full load)
- Design dry bulb: 95°F (mid-way between 0.4% dry bulb and median of extreme highs)
- Design turbine exhaust pressure: 4.5 in Hga (based on assumption that turbines of this age and design trip at 5 in Hga and that the plant would not wish to reduce output on the hottest days)
- Corresponding condensing temperature: 130°F

Therefore, ACC design ITD ($T_{condensing}$ - $T_{design\ ambient}$) = 130°F – 95°F = 35°F

Dry Cooling Retrofit Costs

AC costs can be roughly estimated from EPRI Report No. 1005358; “Comparison of Alternate Cooling Technologies for U.S. Power Plants”, August, 2004.

Vendor information for a design of:

Steam flow: 3,270,000 lb/hr (scaled from example case of 1,080,000 lb/hr)
ITD: 35°F
Price: 2002 $

It should be noted at the outset that this would be a very large ACC with between 80 and 100 cells. This would be the largest ACC on a single unit anywhere in the world to my knowledge. Cost extrapolations to this size range are uncertain without obtaining confirming estimates from vendors which is beyond the scope of this effort. However, the cost estimate *for each unit* based on straight-forward linear extrapolation from more normal sizes is given below.

Table B-108
Dry Cooling Retrofit Cost Estimates

Source/Basis	Equipment	Erection	Electrical	Duct Work	Indirect	Total	Cells
Vendor 1	$56,901,976	$24,351,064	$3,727,204	$372,720	$49,288,541	$134,641,505	125
Vendor 2	$59,635,258	$25,593,465	$2,981,763	$372,720	$51,162,082	$139,745,289	100
Vendor 3	$48,702,128	$23,854,103	$2,981,763	$372,720	$43,812,036	$119,722,751	100
Average	$55,080,616	$24,599,544	$3,230,243	$372,720	$48,088,381	$131,369,020	110
Scaled to 2007 $	$73,709,179	$29,298,305	$4,323,556	$499,445	$62,251,755	$170,079,757	
Including Indirects	$116,460,503	$46,291,323	$6,831,219	$789,124	$98,357,773	$268,726,016	

This would result in the cost of the plant's retrofit cost to dry cooling of over $500,000,000, require the siting of two ACC's each nearly 1,000 feet long and consume approximately 30 MW of fan power. No further consideration will be given to dry cooling at this site.

Effect on Plant Performance

A retrofitted cooling system of either the wet or dry type would have a deleterious effect on the plant net heat rate. This arises from two effects:

1. Considering only the wet system, the power requirements will be higher than the current pumping power requirements for the once-through system. This power is used for the additional circulating pumps and for the cooling tower fans and represents power that must be generated but cannot be sold.
2. The plant will operate at a higher backpressure and therefore a higher heat rate with closed cycle cooling. This effect will be much more pronounced for a dry system than for a wet system.

The additional power requirements are estimated as follows:

Pumping power: The circulating water flow rate must be pumped through an additional head rise. This will be estimated at 40 feet to account for the lift out of the sump, the rise to the hot water distribution deck on the top of the tower and the head loss through the circulating water lines. A combined pump/motor efficiency of 75% is assumed. Each of these factors would be refined in a detailed analysis, but these are considered adequate to give a reasonable estimate of the effect of additional operating power on the plant. For the two units at Ormond Beach:

Table B-109
Ormond Beach Units: Retrofit Additional Pumping Power

Unit	Flow	Head	Eff	Power	Motor
	gpm	ft		kW	MW
1	227,000	40	0.75	1709.8	2.28
2	227,000	40	0.75	1709.8	2.28

Fan power: Similarly cooling tower fan power can be roughly estimated. It is assumed for retrofits on older, lower capacity factor units, the tower would be sized to "low first cost" design since the number of operating hours is low and power penalties are less severe. This is consistent with the assumptions made in the retrofit capital cost estimates. The number of cells will be estimated as one cell per 10,000 gpm of circulating water flow, the fan horsepower at 200 HP and a motor efficiency of 90%. For the Ormond Beach units this results in:

Table B-110
Ormond Beach Units: Retrofit Fan Power

Unit	Flow	Cells	Eff	Power	Motor
	gpm	n		hp	kW
1	227,000	23	0.9	4,540	3,763
2	227,000	23	0.9	4,540	3,763

This represents a combined, full-load operating power requirement of approximately 12. MW or slightly less than 1.0 % of the plant power rating of 1,500 MW. The actual annual cost will obviously depend on the capacity factor, the number of hours on-line, and whether some fans are turned off when operating at part load. Also, the cooling system was sized for full load at acceptable backpressures at so-called "1%" ambient conditions, it would be well oversized for nearly the entire year. Therefore, the effect of requiring additional operating power for the pumps and fans coupled with operation at higher heat rate would be an increase in the fuel burned rather than a reduction in plant output.

Heat rate penalty: As seen in the earlier plot of comparative backpressure, the condensing pressure with closed-cycle wet cooling will run typically 1. to 1.5 in Hga higher than it would with once-through ocean cooling and increases to about 4.5 in Hga on the hottest days. The effect is less at part load. No information is available to estimate the heat rate penalty under these operating conditions.

Capacity Limits

The increased back pressure will likely result in an output restriction at the hottest day. The magnitude of the shortfall will depend on the operating philosophy. If the firing rate is held constant, a 2.5 to 4 % heat rate penalty (plausible estimate based on units of similar age and design) would correspond to roughly a 2.5 to 4 % reduction in output. This might be compensated for partially by overfiring the unit if possible, but the heat rate penalty and hence the fuel costs, would increase even further.

If, however, it were to be decided that operation at a backpressure of 4.5 in Hga constituted an unacceptable maintenance risk to the turbine, then the firing rate would need to be reduced to hold whatever backpressure was consider acceptable. Information to estimate what the shortfall would be in that case is not available but presumably could be estimated by plant staff based on the information given above.

Maintenance Costs

Commonly used factors for maintenance (labor, materials, chemicals, etc.) for wet cooling systems range from 2. to 3. % of the system capital costs.

For wet systems, the important costs are for water treatment, biofouling control and keeping the basin clean. Using salt water and having salt drift around the plant would require rust control, extra painting, etc. Using the high end of typical factors, assume 3. to 3.5% of the capital cost of the tower. It is unclear how Reliant would allocate these costs between operation and maintenance, but an estimate of 3% of the "average" capital costs for all units of $130 million could amount to approximately $4,000,000 per year.

Additional Cost Considerations

Although the S&W costs are pretty close to the Maulbetsch Consulting survey's "Average" difficulty estimate, neither of those estimates can account for any site-specific difficulties which might be encountered at the Ormond Beach site. Those items that could cause a retrofit at this site to be in a different, either "High" or "Easy" category include:

- Difficulty in locating the tower
- Unusual site preparation costs
- Significant interferences to the cost of installation of the circulating water lines
- The need for cooling tower plume abatement
- Stringent noise control
- The use of an alternate make-up water

Location of Tower/Unusual Site Preparation Costs/Interferences

Although no definite information on restrictions on the use of areas of the plant property are available, it appears from the aerial view of the plant boundaries and the neighboring areas, that adequate room for cooling towers exists, particularly to the east or inland side of the plant.

No information is available on site geology or soil characteristics. If, as is sometimes the case in near coastal areas, the ground is saturated and unstable, the installation of the tower basin and the circulating water lines may be difficult.

There is no information on underground infrastructure from which to estimate the likelihood of interferences to the installation of circulating water lines.

Plume Abatement

Based on the view in the aerial photo of the neighboring area, it appears that a visible plume should not be a serious issue at this site primarily from either an aesthetic or safety viewpoint. There should be no need for a plume abatement tower at this site.

Aesthetics

In addition to any issues with a visual plume, the simple appearance of a cooling tower is sometimes considered an aesthetic affront. In this instance, even though the towers would be visible from the beach, considering the size and bulk of the plant buildings already present, it does not appear that this should present a major problem.

Noise Control

Noise from wet cooling towers comes both from the fans and from the water cascading through the fill. Fan noise can be diminished by fan design or the reduction in air velocity which sometime requires the use of bigger, or more, cells. The water noise is more difficult to reduce and usually requires the construction of sound barriers around the cooling tower. As in the case of the plume abatement question, the aerial photo of the plant and the neighboring area makes it appear that cooling tower noise should not be a serious constraint.

Alternate Sources of Make-Up Water

There do not appear to be any nearby alternate sources of make-up water, although no specific information is available on this question. Therefore, the use of seawater make-up is assumed for this site.

Shutdown Period

There is often concern over the period of post plant availability during the retrofit construction period. In this instance, it appears that the major part of the construction could be done while the plant is on-line, with shutdown required only for the final tie-in of the circulating water lines to the existing water circuit. There is no information available to estimate how long this might be. However, recent capacity factors are quite low, and it would appear that the tie-in could be accomplished with no significant downtime.

Other Environmental Issues

Retrofit to a closed-cycle cooling system introduces some environmental issues which a once-through cooling system does not. These are increased air emissions from the stack and drift from the cooling tower.

Stack Emissions

In an earlier section it was noted that a closed-cycle retrofit increase the unit net output because of heat rate penalties and the use of increased operating power. Although no specific heat rate information is available for these units, a reasonable estimate based on units of similar age and design might be in the range of from 5 to 10%. Therefore, the delivery of the same amount of electric power to the grid may require the burning of additional fuel at some location to make up that lost at Ormond Beach. If the relatively low frequency of operation at Ormond Beach implies that when it does operate, it does so at full load then the lost power will have to be made up elsewhere. On the other hand, if operation is normally at partial load, the output might simply be increased at the site except on the very hottest days when the units might be backpressure limited. Therefore, no attempt is made to asses the effect in quantitative terms beyond pointing out that reliable estimates of the shortfall to be expected from full load operation can be made.

Drift

It is assumed that any cooling tower would be equipped with state-of-the-art drift eliminators rated at about 0.0005% of circulating water flow. The following table estimates the amount of drift to be expected from such designs. In addition, as discussed earlier, Federal EPA and State regulations characterize all solids carried off in cooling tower drift as PM10. The cost of offsetting these amount, should it be necessary will vary considerably from site to site as will the severity of the regulatory constraints.

Table B-111
Ormond Beach Drift Estimates

Unit	Flow gpm	Drift[1] gpm	Drift lb/hr	PM10 lb/hr	PM10 tons/year[2]	Cap. Factor %	PM10 tons/year[3]
1	**227,000**	1.14	567	28.36	124.2	**24.7**	**30.7**
2	**227,000**	1.14	567	28.36	124.2	**24.7**	**30.7**

1. At drift eliminator efficiency of 0.0005%
2. Assumes full load all year
3. At 2006 capacity factor

The aerial view of the surrounding area indicates that it is agricultural and salt deposition might be a concern. Although experience at other sites with salt water towers equipped with modern, high efficiency drift eliminators has indicated no detectable off-site damage to crops or agriculture, the possibility should be analyzed in advance of retrofit.

General Conclusion

On balance, it is concluded that there are no obvious problems associated with a retrofit to closed-cycle wet cooling at this site although there may be factors unknown to this study and is estimated to be of "average" difficulty with a likely cost of $125 to 135 million. However, a multi-million dollar retrofit on a plant with capacity factors averaging under 5% in the last two years would warrant careful analysis from a business perspective.

B.12 Pittsburg Generating Station (Mirant)

Location

696 West 10th Street
Pittsburg, CA 94565-1806
38° 02’ 23.08” N; 121° 53’ 39.54” W
Contact: Steve Bauman, 925-427-3381

Figure B-86
Pittsburg Generating Station: Surrounding Area

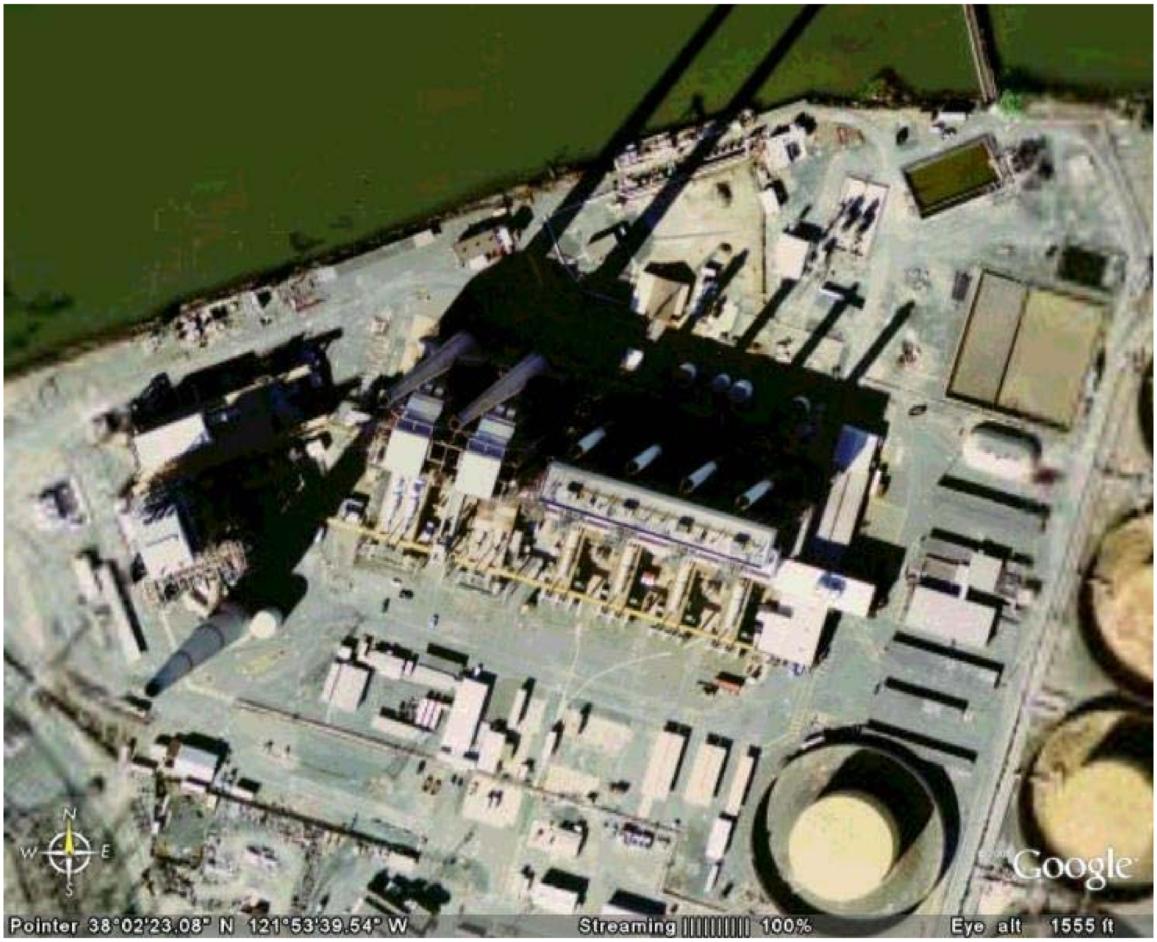


Figure B-87
Pittsburg Generating Station: Site View

Plant/Site Information

Units 5 and 6: 325 MW (once-through cooling)
Unit 7: 720 MW (cooling tower installed)

Table B-112
Pittsburg Cooling System Operating Conditions

Unit	MW	Cooling Water flow		Steam flow	Heat duty	Tin	Tex	Range	Tcond	TTD	Backpressure
		gpm	cfs	lb/hr	Btu/hr	F	F	F	F	F	in Hga
5	**325**	159,875	358	1.711E+06	1.625E+09	62.0	82.3	20.3	89.3	7.0	~ 1.4
6	**325**	159,875	358	1.711E+06	1.625E+09	62.0	82.3	20.3	89.3	7.0	~ 1.4

Table B-113
Pittsburg Capacity Factors

Unit	2001	2002	2003	2004	2005	2006	Average
5	54.4%	19.1%	26.0%	23.1%	12.0%	7.4%	23.7%
6	62.3%	23.9%	7.0%	20.3%	7.1%	5.2%	21.0%
7	71.4%	40.9%	16.3%	9.0%	1.7%	1.4%	23.5%

Table B-114
Pittsburg Meteorological Data

Temperature	Max.	Average	Min.
Pittsburg inlet temp., ºF	84	62	46
Atmos. wet bulb, ºF	74	60	28
Atmos. dry bulb, ºF	112	62	31

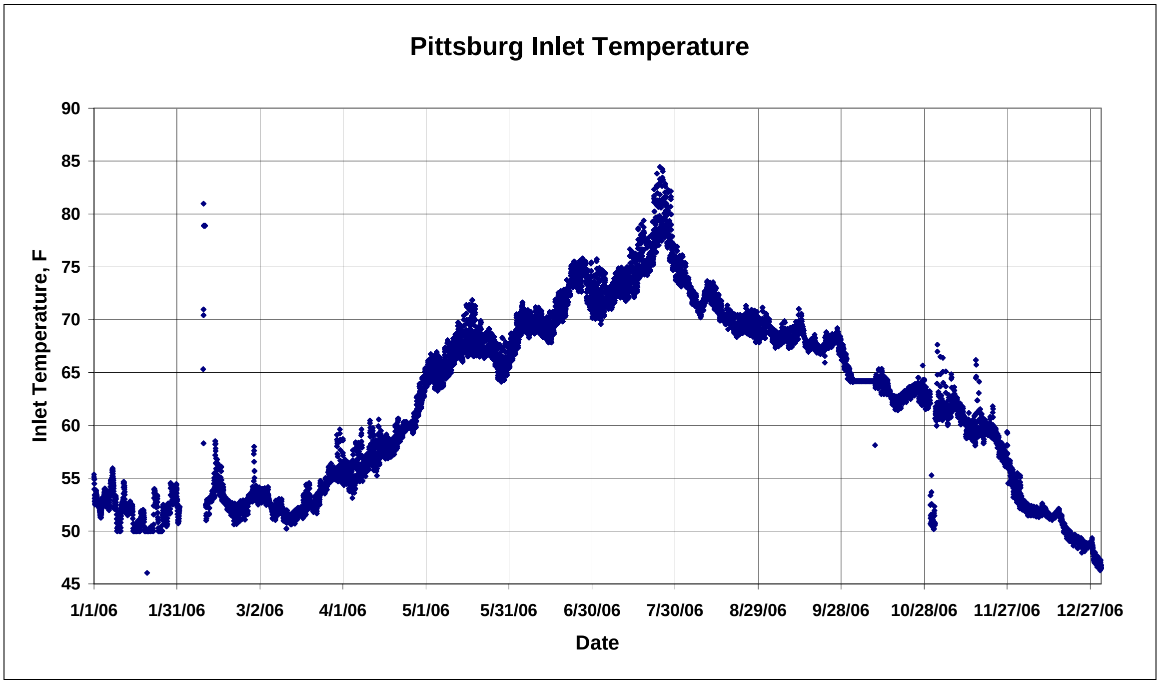


Figure B-88
Pittsburg Inlet Temperature

Plant Operating Data

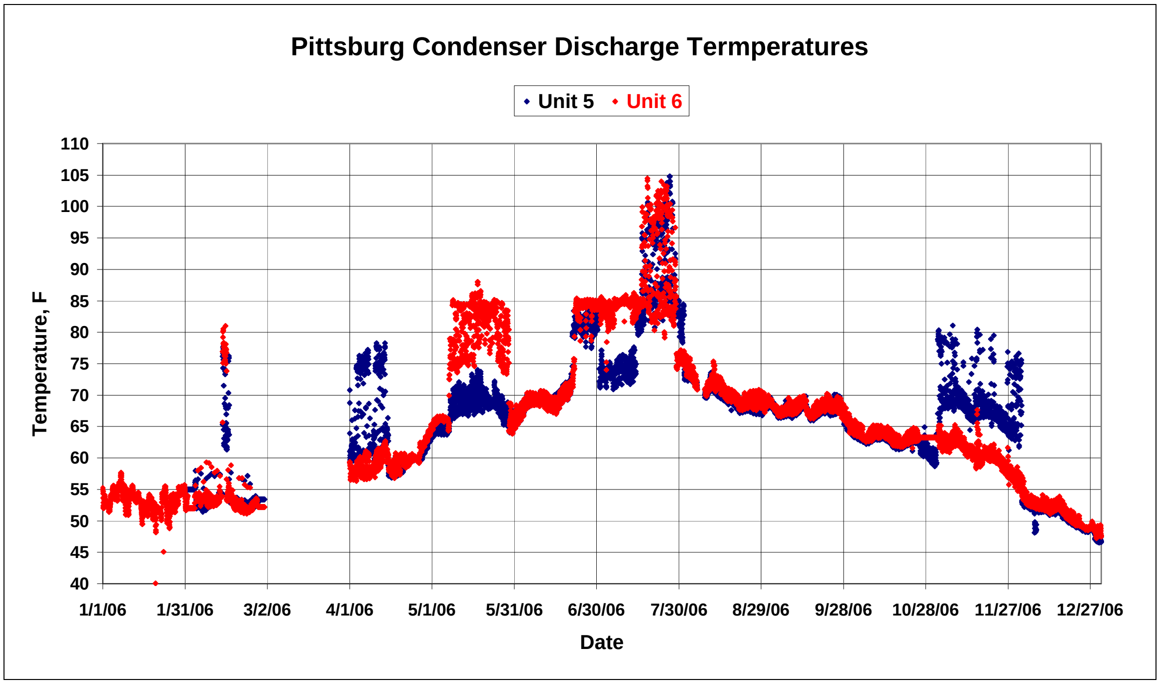


Figure B-89
Pittsburg Condenser Operating Profiles

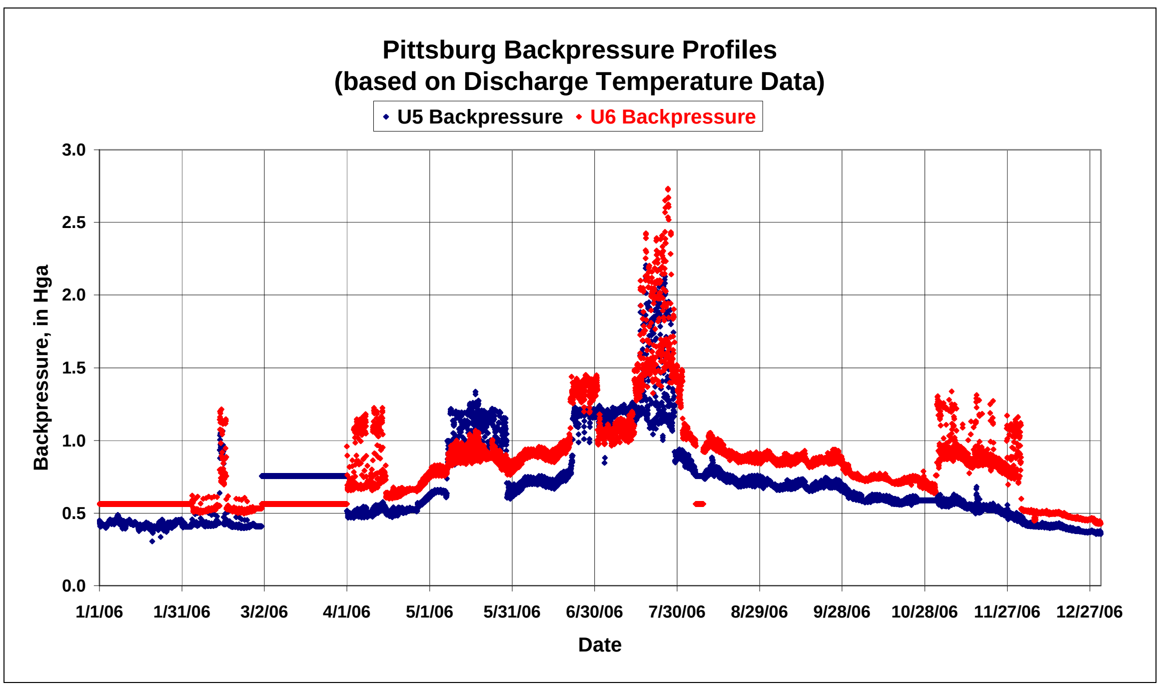


Figure B-90
Pittsburg Backpressure Profiles––Based On Discharge Temperature Data

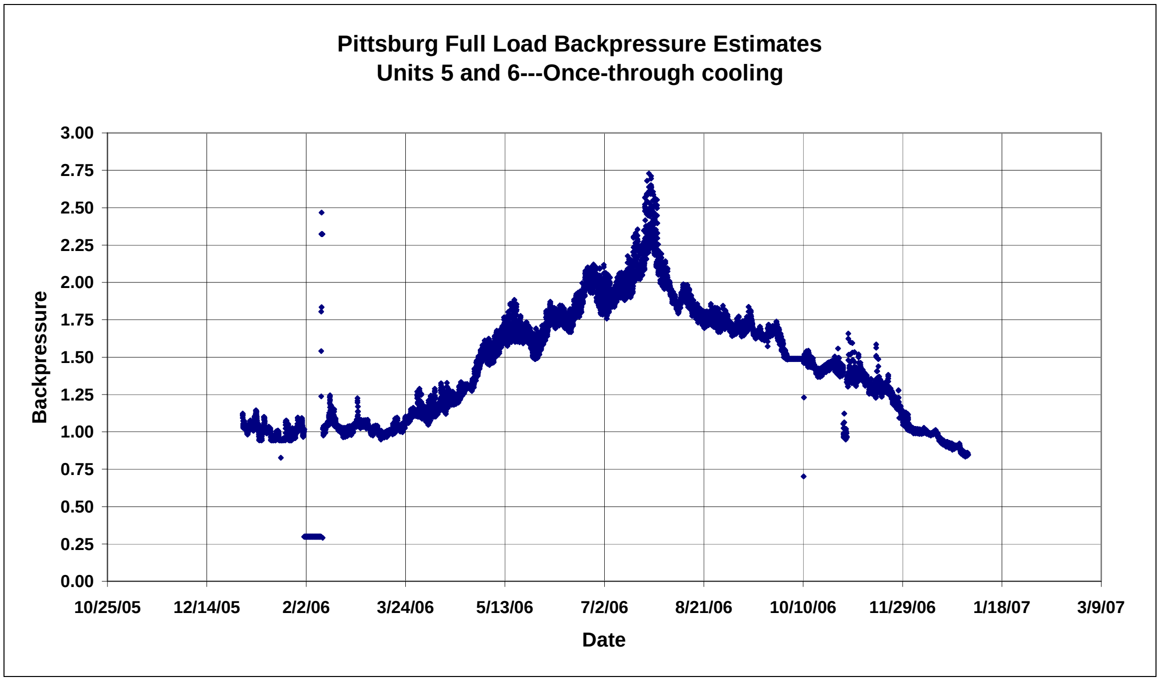


Figure B-91
Estimated Full Load Backpressure––Once-Through Cooling

Cooling Tower Assumptions/Design

Wet cooling system design specs for all units

- Tower type: mechanical draft, counterflow, FRP construction
- Make-up water source: Sea water; 35,000 ppm salinity
- Operating cycles of concentration: n = 1.5
- Evaporation rate: Units 5 and 6--- ~ 3,250 gpm each
- Make-up rate (@ n = 1.5): Units 5 and 6--- ~ 9,750gpm each
- Blowdown (@ n = 1.5): Units 5 and 6--- ~ 6,500 gpm each

Tower design conditions are for all circulating water flows and condenser specifications unchanged, an assumed tower approach of 10°F and a 1% wet bulb temperature of 72°F resulting in

- Ambient wet bulb, design: 72°F
- Approach: 10°F
- Range: 20.3°F
- TTD: 7.0°F

Therefore, the condensing temperature, $T_{cond} = 72 + 10 + 20.3 + 7. = 109.3°F$

with a corresponding backpressure of approximately 2.5 in Hga.

Therefore, on the hottest day at full load, the two units would operate at a backpressure of approximately 2.5 in Hga. Over the course of the year when the ambient wet bulb temperature would be lower, The backpressure would vary as indicated in the following figure. A comparison is given to the backpressure estimated in the previous figure with once-through cooling and indicates that the backpressure would normally be elevated by 0.5 to 1. in Hga.

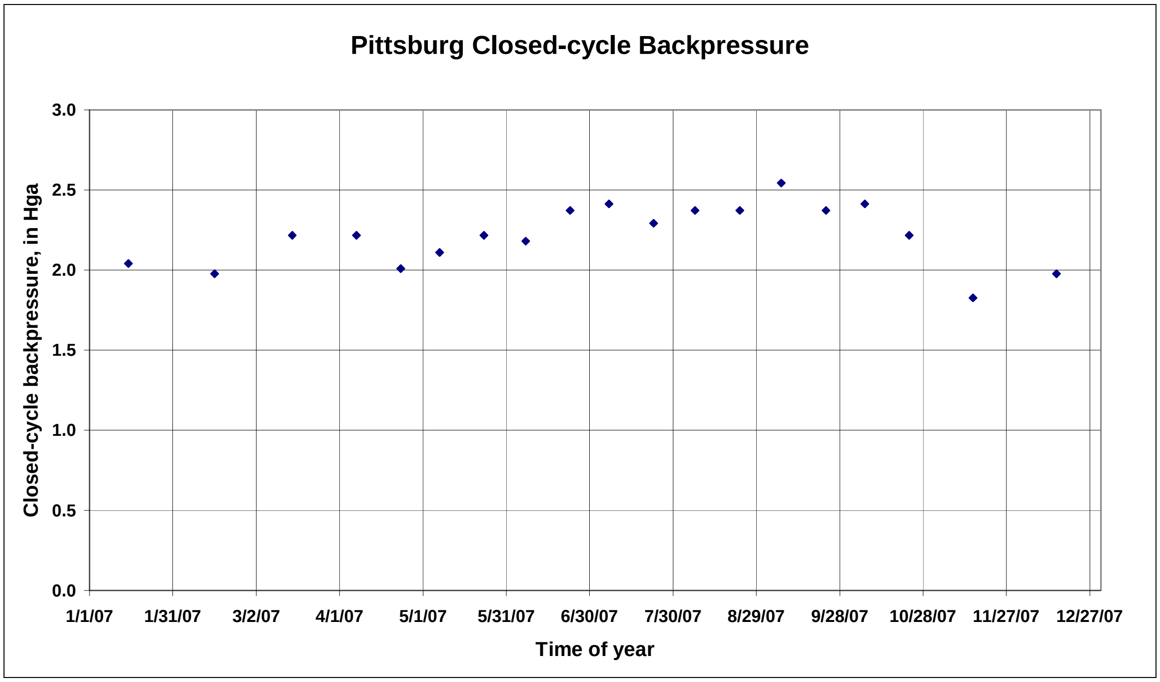


Figure B-92
Closed-Cycle Backpressure

Wet Retrofit Costs

Table B-115
S&W Cost Estimates

S&W Costs---escalated to 2007; x 1.07 for seawater					
Unit	Labor	Material	Equipment	Indirect	Total
5	$11,275,000	$6,572,000	$11,169,000	$16,830,000	$45,846,000
6	$11,275,000	$6,572,000	$11,169,000	$16,830,000	$45,846,000
Plant Total	$22,550,000	$13,144,000	$22,338,000	$33,660,000	$91,692,000

Table B-116
Maulbetsch Consulting Survey Estimates

Maulbetsch Consulting Survey; escalated to 2007 $; x 1.07 for salinity			
Unit	**Easy**	**Average**	**Difficult**
5	**$26,511,000**	**$44,186,000**	**$68,287,000**
6	**$26,511,000**	**$44,186,000**	**$68,287,000**
Plant Total	**$53,022,000**	**$88,372,000**	**$136,574,000**

Dry Cooling

Similar cost estimates can be made for a dry cooling retrofit. The basic assumption is that for plants with low capacity factors, they must be available to produce close to full load on the hottest days of the year when the system load is at its peak. Therefore, for each unit:

- Direct dry cooling: forced, mechanical-draft air-cooled condenser
- Steam flow: ~ 1,711,000 lb/hr (full load)
- Design dry bulb: 105°F (mid-way between 0.4% dry bulb and median of extreme highs)
- Design turbine exhaust pressure: 4.5 in Hga (based on assumption that turbines of this age and design trip at 5 in Hga and that the plant would not wish to reduce output on the hottest days)
- Corresponding condensing temperature: 130°F

Therefore, ACC design ITD ($T_{condensing}$ - $T_{design\ ambient}$) = 130°F – 100°F = **25°F**

Dry Cooling Retrofit Costs

AC costs can be roughly estimated from EPRI Report No. 1005358; “Comparison of Alternate Cooling Technologies for U.S. Power Plants”, August, 2004.

Vendor information for a design of:

Steam flow:1,711,000 lb/hr (scaled from example case of 1,080,000 lb/hr)
ITD: 25°F
Price: 2007 $

Table B-117
Dry Cooling Retrofit Cost Estimates

Source/Basis	Equipment	Erection	Electrical	Duct Work	Indirect	Total	Cells
Vendor 1	$41,683,000	$17,838,000	$2,730,000	$273,000	$36,106,000	$98,630,000	50
Vendor 2	$43,685,000	$18,748,000	$2,184,000	$273,000	$37,478,000	$102,369,000	40
Vendor 3	$35,676,000	$17,474,000	$2,184,000	$273,000	$32,094,000	$87,701,000	40
Average	$40,349,000	$18,020,000	$2,366,000	$273,000	$35,227,000	$96,233,000	45
Scaled to 2007 $	$53,995,000	$21,462,000	$3,167,000	$366,000	$45,602,000	$124,590,000	

Effect on Plant Performance

A retrofitted cooling system of either the wet or dry type would have a deleterious effect on the plant net heat rate. This arises from two effects:

1. Considering only the wet system, the power requirements will be higher than the current pumping power requirements for the once-through system. This power is used for the additional circulating pumps and for the cooling tower fans and represents power that
must be generated but cannot be sold.
2. The plant will operate at a higher backpressure and therefore a higher heat rate with closed cycle cooling. This effect will be much more pronounced for a dry system than for a wet system.

The additional power requirements are estimated as follows:

Pumping power: As noted in Section 4.1.3, the existing circulating water system will discharge into a sump from which a second set of pumps will draw the water and discharge it to the top of the cooling tower. The circulating water flow rate must be pumped through an additional head rise. This will be estimated at 40 feet to account for the lift out of the sump, the rise to the hot water distribution deck on the top of the tower and the head loss through the circulating water lines. A combined pump/motor efficiency of 75% is assumed. Each of these factors would be refined in a detailed analysis, but these are considered adequate to give a reasonable estimate of the effect of additional operating power on the plant. For the two units at Pittsburg:

Table B-118
Pittsburg Units: Retrofit Additional Pumping Power

Unit	Flow	Head	Eff	Power	Motor
	gpm	ft		kW	MW
5	159,875	40	0.75	1204.2	1.61
6	159,875	40	0.75	1204.2	1.61

Fan power: Similarly cooling tower fan power can be roughly estimated. It is assumed for retrofits on older, lower capacity factor units, the tower would be sized to "low first cost" design since the number of operating hours is low and power penalties are less severe. This is consistent with the assumptions made in the retrofit capital cost estimates. The number of cells will be estimated as one cell per 10,000 gpm of circulating water flow, the fan horsepower at 200 HP and a motor efficiency of 90%. For the Pittsburg units this results in:

Table B-119
Pittsburg Units: Retrofit Fan Power

Unit	Flow	Cells	Eff	Power	Motor
	gpm	n		hp	kW
5	159,875	16	0.9	3,198	2,650
6	159,875	16	0.9	3,198	2,650

This represents a combined, full-load operating power requirement of approximately 8.5 MW or approximately 1.3% of the plant power rating of 650 MW. The actual annual cost will obviously depend on the capacity factor, the number of hours on-line, and whether some fans are turned off when operating at part load. Also, the cooling system was sized for full load at acceptable backpressures at so-called "1%" ambient conditions, it would be well oversized for nearly the entire year. Therefore, the effect of requiring additional operating power for the pumps and fans coupled with operation at higher heat rate would be an increase in the fuel burned rather than a reduction in plant output.

Heat rate penalty: As seen in the earlier plot of comparative backpressures, the condensing pressure with closed-cycle wet cooling will run typically 0.5 to 1.0 in Hga higher than it would with once-through ocean cooling and increases to about 2.5 in Hga on the hottest days. The effect is less at part load. No information is available to estimate the effect on heat rate resulting from the increased backpressure. However, information from comparable units suggest an increase of at least 0.25% for each 0.1 in Hga increase in backpressure above design might be reasonable. The comparative plot shown earlier suggests that closed cycle cooling will result in increased backpressure throughout the year ranging from 0.5 to 1. in Hga with a corresponding heat rate penalty of 0.5 to 1.%. In the absence of other information, it is assumed to be applicable to the Pittsburg units as well resulting in a heat rate penalty at full load of 0.5 to 1.% for the units at the plant. It should be noted that some estimates on other individual units of similar size and age have been much higher, up to a heat rate increase of as much as 1,000 Btu/kWh for a backpressure increase of 1.5 to 2.5 in Hga.

Capacity Limits

The increased back pressure will likely result in an output restriction on the hottest day. The magnitude of the shortfall will depend on the operating philosophy. If the firing rate is held constant, a 1% heat rate penalty would correspond to roughly a 1% reduction in output which would appear to be a minor effect on output. If, however, it were to be decided that operation at a backpressure of 2.5 in Hga constituted an unacceptable maintenance risk to the turbine, then the firing rate would need to be reduced to hold whatever backpressure was consider acceptable. Information to estimate what the shortfall would be in that case is not available but presumably could be estimated by plant staff based on the information given above.

Maintenance Costs

Commonly used factors for maintenance (labor, materials, chemicals, etc.) for wet cooling systems range from 2. to 3. % of the system capital costs. For wet systems, the important costs are for water treatment, biofouling control and keeping the basin clean. Using salt water and having salt drift around the plant would require rust control, extra painting, etc. Using the high end of typical factors, assume 3. to 3.5% of the capital cost of the tower. It is unclear how Mirant would allocate these costs between operation and maintenance, but an estimate of 3% of the “average” capital costs for all units of $160 million could amount to approximately $5,000,000 per year.

Additional Cost Considerations

Although the S&W costs are pretty close to the Maulbetsch Consulting survey’s “Average” difficulty estimate, neither of those estimates can account for any site-specific difficulties which might be encountered at the Pittsburg site. Those items that could cause a retrofit at this site to be in a different, either “High” or “Easy” category include:

- Difficulty in locating the tower
- Unusual site preparation costs

- Significant interferences to the cost of installation of the circulating water lines
- The need for cooling tower plume abatement
- Stringent noise control
- The use of an alternate make-up water

Location of Tower/Unusual Site Preparation Costs/Interferences

It appears that space would be available either to the east of the plant if what appear to be unused fuel tanks were removed or to the west in the vicinity of the Unit 7 tower and canal. (See site photo at beginning of write-up).

No information is available regarding the suitability of these sites, but a number of items would need to be considered:

i. The need to demolish, relocate and rebuild existing structures for some locations.

ii. Unstable soil conditions requiring significant foundation work such as deep pilings to stabilize the towers.

iii. Drift deposition from salt water towers.

iv. Underground infrastructure which would make the installation of underground circulating water lines difficult and costly.

v. Remoteness of current intake bays from towers north of the plant and difficulty in tying into the existing circulating water system.

vi. Possible neighborhood objections to visible plumes, corrosive drift and noise.

vii. The need for PM10 offsets for expected drift from seawater towers.

Given, however, that Unit 7 has operated on a cooling tower for many years, it would appear that most of these issue are resolvable.

Plume Abatement

Based on the view in the aerial photo of the neighboring area, it appears that a visible plume could be an issue at this site primarily from an aesthetic viewpoint. However, no plume abatement was required for Unit 7 and presumably would not be for Units 5 and 6.

Aesthetics

In addition to any issues with a visual plume, the simple appearance of a cooling tower is sometimes considered an aesthetic affront. In this instance, even though the towers would be visible to neighbors, considering the number, size and bulk of the plant buildings already present, it does not appear that this would present a major problem.

Noise Control

Noise from wet cooling towers comes both from the fans and from the water cascading through the fill. Fan noise can be diminished by fan design or the reduction in air velocity which sometime requires the use of bigger, or more, cells. The water noise is more difficult to reduce and usually requires the construction of sound barriers around the cooling tower. As in the case of the plume abatement question, the aerial photo of the plant and the neighboring area makes it appear that cooling tower noise should not be a serious constraint. In case that it is, the capital cost of the tower itself cost might increase from 20 to 40%.

Alternate Sources of Make-Up Water

The use of seawater make-up can introduce difficult problems regarding drift and related maintenance considerations. (See later discussion of drift and PM10.) An alternative can be to purchase reclaimed water from nearby municipal water treatment facilities.

If the use of reclaimed water for wet cooling tower makeup were to be considered, the distance of sources from the plant, the cost of installing delivery and return pipelines to the remote sources and the time required to obtain permits must be factored into any estimate of the cost.

Shutdown Period

There is often concern over the period of post plant availability during the retrofit construction period. In this instance, it appears that the major part of the construction could be done while the plant is on-line, with shutdown required only for the final tie-in of the circulating water lines to the existing water circuit. There is no information available to estimate how long this might be. However, the operating profiles implied by the discharge temperature records shown in earlier plots along with the very low capacity factors for the past few years indicate that there are periods of little or no operation. Therefore, it appears that the tie-in could be accomplished with no serious downtime.

Other Environmental Issues

Retrofit to a closed-cycle cooling system introduces some environmental issues which a once-through cooling system does not. These are increased air emissions from the stack and drift from the cooling tower.

Stack Emissions

In an earlier section it was noted that a closed-cycle retrofit increase the unit net output because of heat rate penalties and the use of increased operating power. In this instance these together were estimated at from 1 to 2%. Therefore, the delivery of the same amount of electric power to the grid will require the burning of additional fuel at some location to make up that lost at Pittsburg. Based on the unit heat rate information provided, this does not appear to be major effect in this case. Furthermore, in the discussion of this issue in Chapter 7, it was pointed out that the effect of making up this shortfall was highly variable depending on how and where the replacement per was generated. Therefore, no attempt is made to asses the effect in quantitative terms beyond pointing out that reliable estimates of the shortfall to be expected from full load operation can be made.

Drift

It is assumed that any cooling tower would be equipped with state-of-the-art drift eliminators rated at about 0.0005% of circulating water flow. The following table estimates the amount of drift to be expected from such designs. In addition, as discussed earlier, Federal EPA and State regulations characterize all solids carried off in cooling tower drift as PM10. The cost of offsetting these amount, should it be necessary will vary considerably from site to site as will the severity of the regulatory constraints.

Table B-120
Pittsburg Drift Estimates

	Flow	Drift[1]	Drift	PM10	PM10	Cap. Factor	PM10
Unit	**gpm**	**gpm**	**lb/hr**	**lb/hr**	**tons/year[2]**	**%**	**tons/year[3]**
5	**159,875**	0.80	400	19.98	87.5	**24.7**	**21.6**
6	**159,875**	0.80	400	19.98	87.5	**24.7**	**21.6**

1. At drift eliminator efficiency of 0.0005%
2. Assumes full load all year
3. At 2006 capacity factor

General Conclusion

On balance, it is concluded that the nature of the likely problems and additional costs to be encountered at Pittsburg would put the retrofit at this site in a “average” category. Based on the results from the Maulbetsch Consulting survey presented above, this would put the project cost in the range of $90 million. Additionally, based on declining capacity utilization since 2001 the viability of a retrofit at this facility would warrant careful analysis.

B.13 Potrero (Mirant)

Location

Potrero District
San Francisco, CA
Contact: Steve Bauman, 925-427-3381
37° 45’ 23.84” N; 122° 22’ 55.11” W

Figure B-93
Potrero Boundary and Neighborhood (from URS)

Figure B-94
Potrero Site View

Plant/Site Information

Unit 3: 207 MW

Table B-121
Potrero Cooling System Operating Conditions

Unit	MW	Cooling Water flow		Steam flow	Heat duty	Tin	Tex	Range	Tcond	TTD	Backpressure
		gpm	cfs	lb/hr	Btu/hr	F	F	F	F	F	in Hga
3	**207**	157,000	352	1.463E+06	1.390E+09	60.0	77.7	17.7	84.7	7.0	~ 1.2

Table B-122
Potrero Capacity Factors

Unit	MW (net)	Capacity Factor (%)						
		2001	2002	2003	2004	2005	2006	Average
3	**207**	56.4%	30.0%	45.5%	46.6%	21.3%	28.8%	**34%**

Table B-123
Potrero Meteorological Data

Temperature	Max.	Average	Min.
Potrero inlet temp., ºF	68	60	53
Atmos. wet bulb, ºF	68	50	29
Atmos. dry bulb, ºF	90	63	32

* 0.4% dry bulb = 83 F; median of extreme highs = 96 F (assume 90 F).

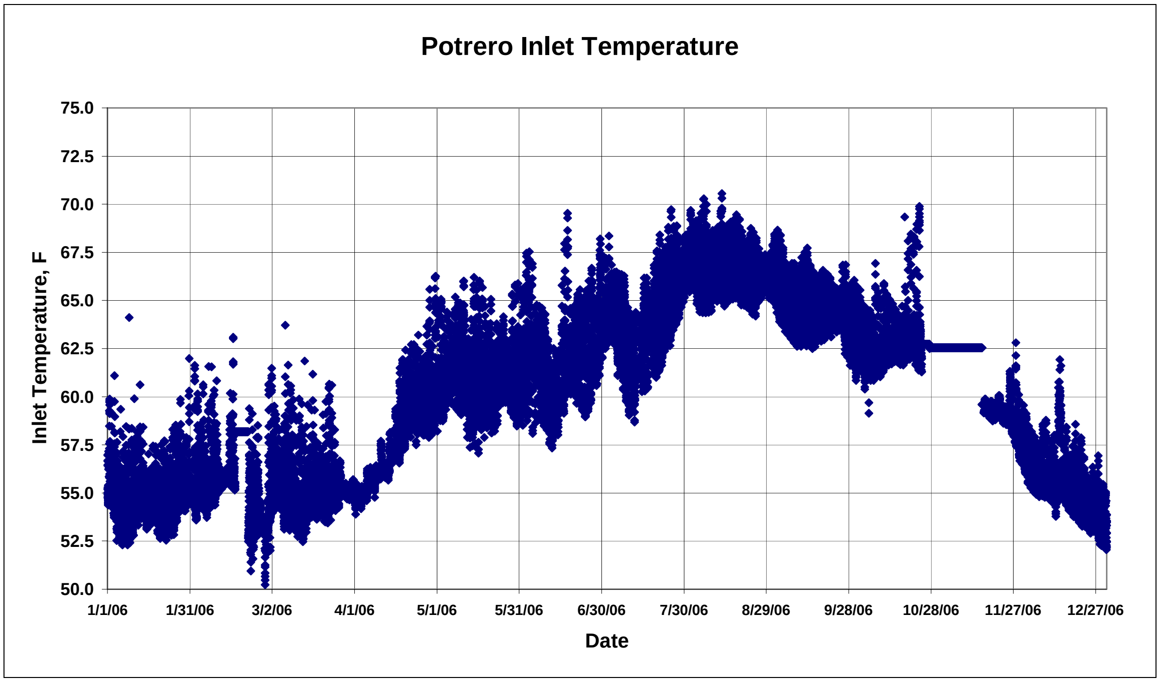


Figure B-95
Potrero Inlet Temperature

Plant Operating Data

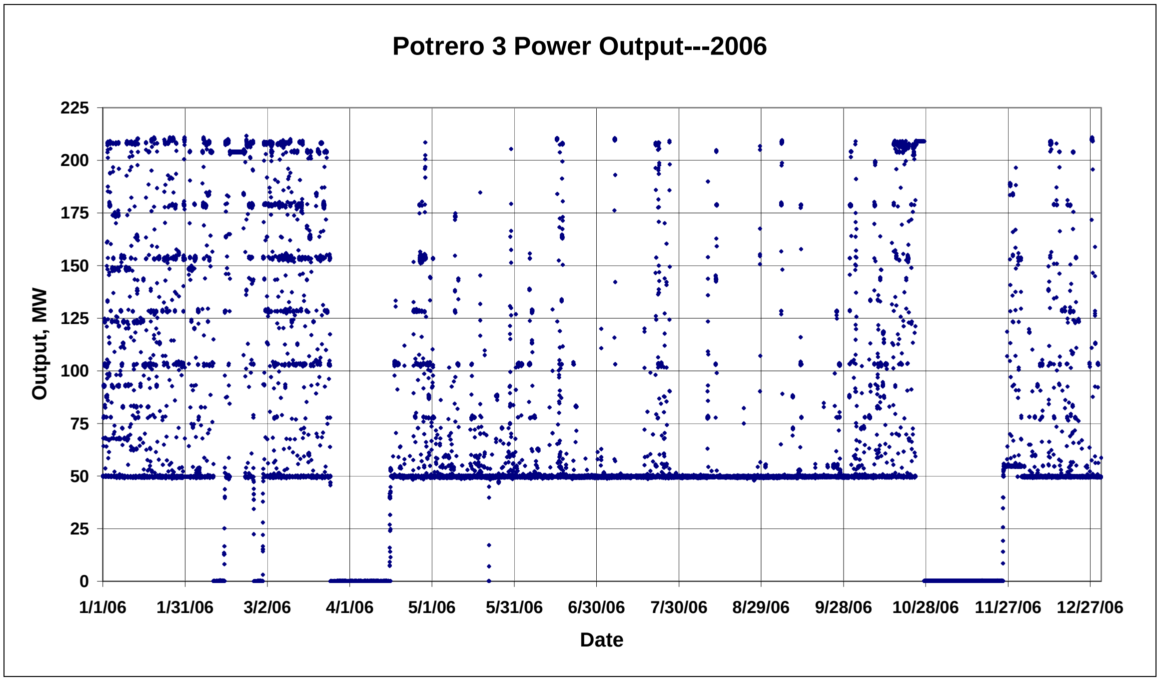


Figure B-96
Potrero Unit 3 Output––2006

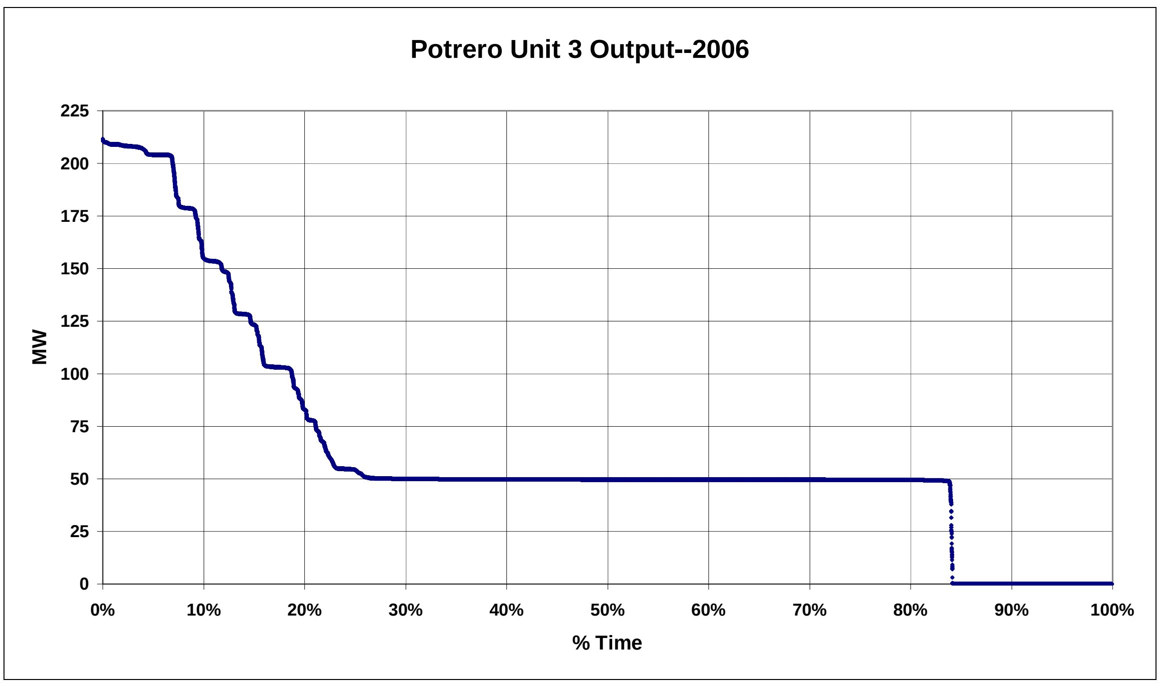


Figure B-97
Potrero Unit 3 Operating Profile––2006

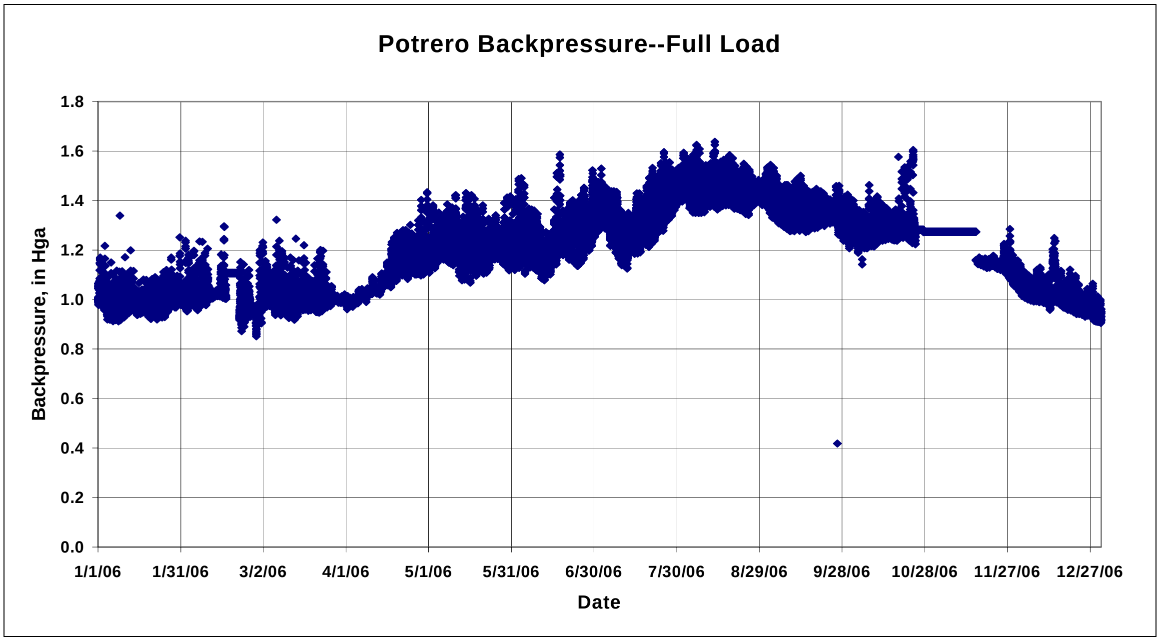


Figure B-98
Potrero Backpressure––Full Load

Cooling System Assumptions

Wet cooling

- Tower type: mechanical draft, counterflow, FRP construction
- Make-up water source: San Francisco Bay; 35,000 ppm salinity
- Operating cycles of concentration: n = 1.5
- Evaporation rate: ~ 2,200 gpm
- Make-up rate (@ n = 1.5): ~6,600 gpm
- Blowdown (@ n = 1.5): ~ 4,400 gpm

Tower design——to conform to once-through cooling operation:

Water flow: 157,000 gpm (unchanged)
Range: 17°F (unchanged)
Design wet bulb: 68°F
Design approach: 10°F (assumed)
Condenser TTD: 7°F (unchanged)

Therefore: Condensing temperature = 68 + 10 +17 +7 = 102°F
Corresponding backpressure = 2.05 in Hga (full load; hot day)

Retrofit Costs for Closed-Cycle Wet System

Stone & Webster 2002 analysis: (National study scaled from 6 base plants)

Amounts	Labor	Materials	Equipment	Indirects	Total
2002 $	$7,620,000	$3,850,000	$6,540,000	$10,380,000	$28,390,000
2007 $	$8,834,000	$5,152,000	$8,752,000	$13,188,000	$35,926,000
x 1.07 for high salinity	$9,452,000	$5,513,000	$9,365,000	$14,111,000	$38,441,000

JSM 2002 Survey report: (based on utility data/estimates for 50 plants)

Amounts	Easy	Average	Difficult
2002 $	$15,918,000	$26,530,000	$37,142,000
2007 $	$20,149,000	$33,582,000	$47,015,000
x 1.07 for high salinity	$21,560,000	$35,933,000	$50,306,000

Comparison with Individual Design If Available

A simple analysis based on the approach discussed in Section 5 resulted in the following range of costs.

	Greenfield	Moderately Difficult	Very Difficult
Total Project Cost	$26,360,000	$46,410,000	$67,030,000
w/o Fuel Tank Removal	$24,910,000	$42,300,000	$60,180,000

Note that the Greenfield cost is close to the "easy" category and the "moderately difficult" is between the "average" and "difficult" cases from the survey.

Dry Cooling

- Direct dry cooling: forced, mechanical-draft air-cooled condenser
- Steam flow: ~ 1,400,000 lb/hr (full load)
- Design dry bulb: 90°F (mid-way between 0.4% dry bulb and median of extreme highs)
- Design turbine exhaust pressure: 4.5 in Hga (based on assumption that turbines of this age and design trip at 5 in Hga and that the plant would not wish to reduce output on the hottest days)
- Corresponding condensing temperature: 130°F

Therefore, ACC design ITD (Initial Temperature Difference): **40°F**

From EPRI Report No.: 1005358; "Comparison of Alternate Cooling Technologies for U.S. Power Plants", August, 2004.

Vendor information for a design of:

Steam flow: 1.40 x 10^6 lb/hr
ITD: 40°F
Price: 2007 $

Dry Cooling Retrofit Costs

Table B-124
Dry Cooling Retrofit Costs

Source/Basis	Equip't	Erection	Electrical	Duct work	Total	Cells
Vendor 1	18,000,000	7,700,000	900,000	150,000	26,750,000	30
Vendor 2	14,900,000	7,300,000	900,000	150,000	23,250,000	30
Average	16,450,000	7,500,000	900,000	150,000	25,000,000	30
Scaled to 2007$	$20,563,000	$9,375,000	$1,125,000	$188,000	$31,250,000	
Scaled to design steam flow	$26,731,000	$12,188,000	$1,463,000	$244,000	$40,625,000	40
Including indirects	$42,235,000	$19,256,000	$2,311,000	$385,000	$64,188,000	

Things that Could Make the Costs Higher

We noted that the S&W costs are pretty close to the survey's "Average" difficulty estimate. There are a few things that could make this retrofit be in the "High" difficulty category.
These include:

- High site preparation costs
- High costs of installation for the circulating water lines from possible underground interferences
- Plume abatement
- Stringent noise control
- Inability to withdraw water from the Bay

High Site Preparation Costs

There may be contaminated soil in the area north of the plant, which if disturbed, might entail high clean-up costs. I have no way of knowing whether or not this would be the case, but, assume that you have to excavate, say, 4 feet down for the cold water basin under the tower, with an area of 50 x 720 feet. This gives over 5,000 yards of soil. The disposal or treatment cost in this case could be highly variable, but no information is available to assess the magnitude of the costs.

No information on the geology underlying the site is available. If it is soft soil, it may be necessary to set piles to support the tower. If it is saturated, it may be necessary to pump out water during the excavation for the tower basin or the circulating water lines, and then sealing the pit or trenches. The costs for site prep and installation of the circ. water lines in the S&W spreadsheets, typically together, are greater than the tower itself. If these costs were to double due to either of these conditions, it could easily add 5 to 10 million to the cost of the project.

It is possible, even likely, that the site will be over "Bay Mud" so the soil will be mushy. Also, a significant portion of the shore line around the Bay is fill so it may lack the integrity to support a cooling tower without piles.

Installation of Circulating Water Lines

Costs for “easy installation” have been estimated at $11/in-dia/ft. If this pipe has to run ~ 1,500 feet, the cost would be ~$1.6 million. This cost assumes no interferences. Circulating water lines that went in at an existing plant in the Monterey Bay area which ran across the old plant property ran into literally hundreds of interferences, and the cost was several times the $11/in-ft quoted above.

It has been suggested at some sites that the lines might be run above ground. This might be a lower cost solution, but the pipe would have to be reinforced, supported and protected. No information is available to assess the costs relative to conventional installation.

Effect on Plant Performance

A retrofitted cooling system of either the wet or dry type would have a deleterious effect on the plant net heat rate. This arises from two effects:

1. Considering only the wet system, the power requirements will be higher than the current pumping power requirements for the once-through system. This power is used for the additional circulating pumps and for the cooling tower fans and represents power that
must be generated but cannot be sold.

2. The plant will operate at a higher backpressure and therefore a higher heat rate with closed cycle cooling. This effect will be much more pronounced for a dry system than for a wet system.

The additional power requirements are estimated as follows:

Pumping power: As noted in Section 4.1.3, the existing circulating water system will discharge into a sump from which a second set of pumps will draw the water and discharge it to the top of the cooling tower. The circulating water flow rate must be pumped through an additional head rise. This will be estimated at 40 feet to account for the lift out of the sump, the rise to the hot water distribution deck on the top of the tower and the head loss through the circulating water lines. A combined pump/motor efficiency of 75% is assumed. Each of these factors would be refined in a detailed analysis, but these are considered adequate to give a reasonable estimate of the effect of additional operating power on the plant. For the several units at Potrero:

Table B-125
Potrero Units: Retrofit Additional Pumping Power

Unit	Flow	Head	Eff	Power	Motor
	gpm	ft		kW	MW
3	157,000	40	0.75	1182.6	1.58

Fan power: Similarly cooling tower fan power can be roughly estimated. It is assumed for retrofits on older, lower capacity factor units, the tower would be sized to “low first cost” design since the number of operating hours is low and power penalties are less severe. This is consistent with the assumptions made in the retrofit capital cost estimates. The number of cells will be estimated as one cell per 10,000 gpm of circulating water flow, the fan horsepower at 200 HP and a motor efficiency of 90%. For the Potrero units this results in:

Table B-126
Potrero Units: Retrofit Fan Power

Unit	Flow	Cells	Eff	Power	Motor
	gpm	n		hp	kW
3	157,000	16	0.9	3,140	2,603

This represents a combined, full-load operating power requirement of approximately 4.2 MW or approximately 2 % of the plant power rating of 207 MW. The actual annual cost will obviously depend on the capacity factor, the number of hours on-line, and whether some fans are turned off when operating at part load. Also, the cooling system was sized for full load at acceptable backpressures at so-called “1%” ambient conditions, it would be well oversized for nearly the entire year. Therefore, the effect of requiring additional operating power for the pumps and fans coupled with operation at higher heat rate would be an increase in the fuel burned rather than a reduction in plant output.

For a nominal heat rate of 12,000 Btu/kWh (this may be high but it is not unusual for other turbines of this vintage operating at part load),

4,300 kW x 12,000 Btu/kW-hr x 8760 hr/yr x .85 operating time = 3.85 x 10^5 MMBtu/yr

At an assumed fuel cost of $8.00/MMBtu, this is $3.0 million per year. This, however, could be reduced substantially by turning off fans most of the time when operating at reduced load (50 MW seems typical).

For a Dry Cooling System

Fan power (40 fans @ 250 HP): 7.5 MW (at full load)

Again, since we designed the system to maintain 4.5 in Hga backpressure at the hottest day, the ACC would be loafing most of the year, and I would expect that the annual average power would be less than half the full load value and maybe no more than one-quarter. However, using the same assumptions of efficiency, fuel cost, etc. as for the wet system, the additional fuel cost for full load operation all year would be ~$6.4 million.

Fan power (40 fans @ 250 HP): 7.5 MW (at full load)

Again, since we designed the system to maintain 4.5 in Hga backpressure at the hottest day, the ACC would be loafing most of the year, and I would expect that the annual average power would be less than half the full load value and maybe no more than one-quarter. However, using the same assumptions of efficiency, fuel cost, etc. as for the wet system, the additional fuel cost for full load operation all year would be ~$6.4 million.

Heat rate penalty: As seen in the earlier plot of comparative backpressures, the condensing pressure with closed-cycle wet cooling will run typically 0.25 to 0.5 in Hga higher than it would with once-through ocean cooling and increases to about 2.05 in Hga on the hottest days. The effect is less at part load. No information is available to estimate the effect on heat rate resulting from the increased backpressure. However, information from comparable units suggest an increase of at least 0.25% for each 0.1 in Hga increase in backpressure above design might be reasonable. The comparative plot shown earlier suggest that closed cycle cooling will result in increased backpressure throughout the year ranging from 0.5 to 1. in Hga with a corresponding heat rate penalty of 0.5 to 1.%. In the absence of other information, it is assumed to be applicable to the Potrero unit as well resulting in a heat rate penalty at full load of 0.5 to 1.% for the units at the plant. It should be noted that some estimates on other individual units of similar size and age have been much higher, up to a heat rate increase of as much as 1,000 Btu/kWh for a backpressure increase of 1.5 to 2.5 in Hga..

Capacity Limits

The increased back pressure will likely results in an output restriction at the hottest day. The magnitude of the shortfall will depend on the operating philosophy. If the firing rate is held constant, a 1% heat rate penalty would correspond to roughly a 1% reduction in output which would appear to be a minor effect on output. If, however, it were to be decided that operation at a backpressure of 2.05 in Hga constituted an unacceptable maintenance risk to the turbine, then the firing rate would need to be reduced to hold whatever backpressure was consider acceptable. Information to estimate what the shortfall would be in that case is not available but presumably could be estimated by plant staff based on the information given above.

Maintenance Costs

For wet systems, it’s mostly water treatment, biofouling control and keeping the basin clean. Using salt water and having salt drift around the plant there would be rust control, extra painting, etc. Using the high end of the factors, assume 3. to 3.5% of the capital cost of the tower. In this case,

0.03 x 5.5 million = $165,000 per year

Additional Cost Considerations

Although the S&W costs are pretty close to the Maulbetsch Consulting survey’s “Average” difficulty estimate, neither of those estimates can account for any site-specific difficulties which might be encountered at the Harbor site. Those items that could cause a retrofit at this site to be in a different, either “High” or “Easy” category include:

- Difficulty in locating the tower
- Unusual site preparation costs
- Significant interferences to the cost of installation of the circulating water lines
- The need for cooling tower plume abatement
- Stringent noise control
- The use of an alternate make-up water

Location of Tower/Unusual Site Preparation Costs/Interferences

Wet tower siting: The wet tower size would likely be about 15 cells, giving a cell water loading of 10,500 gpm per cell. Cell dimensions might typically be 48' x 48' giving overall tower dimensions of approximately 50' x 730' for an in-line arrangement. It appears that there would be room north of the plant for a tower of this size. Alternatively a 14 or 16 cell "back-to-back" tower would be shorter but wider (~ 100' x 360'). A back-to-back tower is necessarily higher increasing the pumping head on the new circulating water pumps from ~ 30 feet to perhaps 40 to 45 feet.

ACC siting: If the 40 cells were arranged in an 8 x 5 configuration, the footprint would be roughly 400' x 250'. The fan deck would be about 60 to 65 feet high with the top of the steam duct and 100 to 110 feet. There would appear to be room north of the plant for the ACC.

However, getting the steam to the ACC may be difficult. The exhaust flange of the steam turbine appears to be at the south end of the turbine hall. Therefore, the steam duct, which might be attached to a modified turbine flange (requiring the removal of the condensers and perhaps some structural work in the neighborhood of the turbine exit) would have to be brought over the top of the turbine hall and then routed north to the ACC. In a brief conversation with Dave Hansel, the Plant Manger, he said that he thought that "it could be done with difficulty". The effect on cost would be primarily on the cost of the steam duct, which is normally estimated as a minor cost element of perhaps $200,000 to $300,000. A more difficult installation could presumably quadruple this (*or more*) but still would not be a major effect on the cost. A more detailed inspection would be required to confirm that the tie in is not so difficult as to preclude dry cooing at the site.

All locations had serious drawbacks including

i. The need to demolish, relocate and rebuild existing structures for some locations.

ii. Unstable soil conditions requiring significant foundation work such as deep pilings to stabilize the towers.

iii. Drift deposition from salt water towers.

iv. Underground infrastructure which would make the installation of underground circulating water lines difficult and costly.

v. Remoteness of current intake bays (especially for Units 5, 6 and 8) from towers north of the plant and difficulty in tying into the existing circulating water system.

vi. Probable neighborhood objections to visible plumes, corrosive drift and noise.

vii. The need for PM10 offsets for expected drift from seawater towers.

Plume Abatement

Based on the view in the aerial photo of the neighboring area, it appears that a visible plume would not be a serious issue at this site from an aesthetic viewpoint. It is reasonable to assume that a plume abatement tower would not be required.

Aesthetics

In addition to any issues with a visual plume, the simple appearance of a cooling tower is sometimes considered an aesthetic affront. In this instance, even though the towers would be visible to neighbors, considering the number and size bulk of the plant buildings already present, it does not appear that this would present a major problem.

Noise Control

Noise from wet cooling towers comes both from the fans and from the water cascading through the fill. Fan noise can be diminished by fan design or the reduction in air velocity which sometime requires the use of bigger, or more, cells. The water noise is more difficult to reduce and usually requires the construction of sound barriers around the cooling tower. Based on the appearance of the neighborhood in the aerial site photo, it doesn’t appear that noise should be a serious constraint. In case that it is, the *tower* cost might increase from 20 to 40%. A noise survey should be conducted to determine background noise before deciding this is not an issue.

Alternate Sources of Make-Up Water

The use of seawater make-up can introduce intractable problems regarding drift and related maintenance considerations. (See later discussion of drift and PM10.) An alternative can be to purchase reclaimed water from nearby municipal water treatment facilities.

If permitting issues were to prohibit you from using Bay water as make-up to the cooling tower, you would presumably have to purchase reclaimed water from some municipal water treatment facility. The major cost effect would be on the delivery of water to the site and on the negotiated purchase price. No information is available with which to quantify this cost. However, it is believed that this was looked into during the hearings on Unit 7, and there may be useful data in Potrero files on the subject.

Shutdown Period

There is often concern over the period of post plant availability during the retrofit construction period. In this instance, it appears that the major part of the construction could be done while the plant is on-line, with shutdown required only for the final tie-in of the circulating water lines to the existing water circuit. There is no information available to estimate how long this might be. However, the operating profiles shown earlier for 2005 indicate periods of little or no operation. Therefore, it appears that the tie-in could be accomplished with no serious downtime.

Other Environmental Issues

Retrofit to a closed-cycle cooling system introduces some environmental issues which a once-through cooling system does not. These are increased air emissions from the stack and drift from the cooling tower.

Stack Emissions

In an earlier section it was noted that a closed-cycle retrofit increase the unit net output because of heat rate penalties and the use of increased operating power. In this instance these together were estimated at from 1 to 2%. Therefore, the delivery of the same amount of electric power to the grid will require the burning of additional fuel at some location to make up that lost at Potrero. Based on the unit heat rate information provided, this does not appear to be major effect in this case. Furthermore, in the discussion of this issue in Chapter 7, it was pointed out that the effect of making up this shortfall was highly variable depending on how and where the replacement per was generated. Therefore, no attempt is made to asses the effect in quantitative terms beyond pointing out that reliable estimates of the shortfall to be expected from full load operation can be made.

Drift

It is assumed that any cooling tower would be equipped with state-of-the-art drift eliminators rated at about 0.0005% of circulating water flow. The following table estimates the amount of drift to be expected from such designs. In addition, as discussed earlier, Federal EPA and State regulations characterize all solids carried off in cooling tower drift as PM10. The cost of offsetting these amount, should it be necessary will vary considerably from site to site as will the severity of the regulatory constraints.

Table B-127
Potrero Drift Estimates

Unit	Flow gpm	Drift[1] gpm	Drift lb/hr	PM10 lb/hr	PM10 tons/year[2]	Cap. Factor %	PM10 tons/year[3]
3	**157,000**	0.79	392	19.62	85.9	**24.7**	**21.2**

1. At drift eliminator efficiency of 0.0005%
2. Assumes full load all year
3. At 2006 capacity factor

General Conclusion

On balance, it is concluded that the nature of the likely problems and additional costs to be encountered at Potrero would put the retrofit at this site in an “average” category. Based on the results from the Maulbetsch Consulting survey presented above, this would put the project cost in the range of $36 million. As a result of the declining capacity utilization of this facility since 2001 the economic viability of a retrofit would warrant careful analysis.

B.14 Redondo Beach Power Station (AES Southland Corporation)

Location

1100 N. Harbor Drive
Redondo Beach, CA 90277
33° 50’ 58.86” N; 118° 23’ 38.03”
Steve Maghy, 562-493-7384

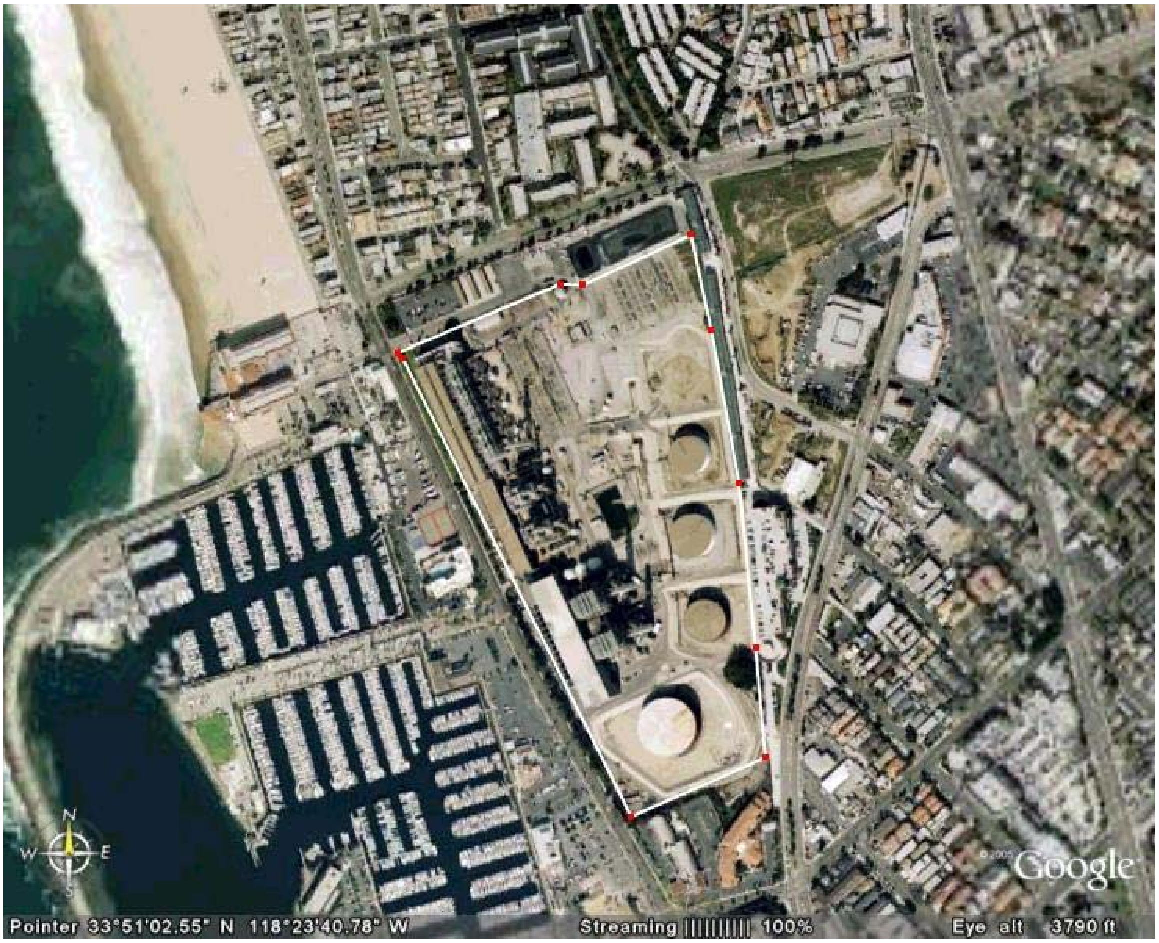


Figure B-99
Redondo Beach Power Station: Boundary and Neighborhood

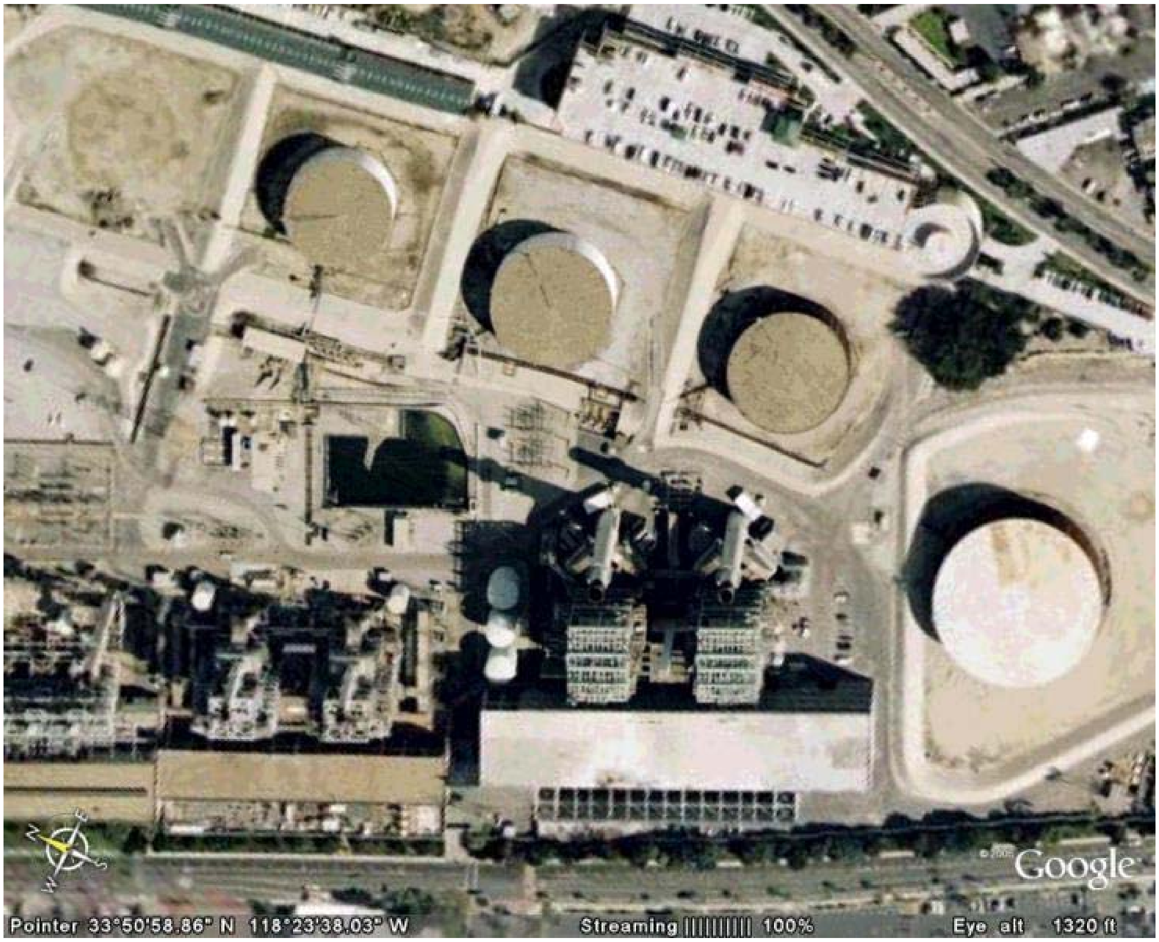


Figure B-100
Redondo Beach Power Station: Site View

Plant/Site Information

Unit 5: 175 MW
Unit 6: 175 MW
Unit 7: 480 MW
Unit 8: 480 MW

Table B-128
Redondo Beach Cooling System Operating Conditions

Unit	MW	Cooling Water flow		Steam flow	Heat duty	Tin	Tex	Range	Tcond	TTD	Backpressure
		gpm	cfs	lb/hr	Btu/hr	F	F	F	F	F	in Hga
5	**175**	72,000	160	9.211E+05	8.750E+08	63.0	87.3	24.3	94.3	7.0	~ 1.6
6	**175**	72,000	160	9.211E+05	8.750E+08	63.0	87.3	24.3	94.3	7.0	~ 1.6
7	**480**	234,000	521	2.526E+06	2.400E+09	63.0	83.5	20.5	90.5	7.0	~ 1.45
8	**480**	234,000	521	2.526E+06	2.400E+09	63.0	83.5	20.5	90.5	7.0	~ 1.45

Table B-129
Redondo Beach Capacity Factors

Unit	MW (net)	Capacity Factor (%)						
		2001	2002	2003	2004	2005	2006	Average
5	**175**	10.8%	5.4%	8.3%	2.3%	1.0%	1.7%	**4%**
6	**175**	24.3%	3.1%	1.7%	1.5%	1.1%	1.7%	**2%**
7	**480**	67.2%	22.8%	12.6%	17.5%	6.6%	6.7%	**13%**
8	480	66.7%	23.2%	8.6%	11.1%	2.7%	5.6%	**10%**

Table B-130
Redondo Beach Meteorological Data

Temperature	Max.	Average	Min.
Redondo Beach inlet temp., °F	68	63	58
Atmos. wet bulb, °F	~73	~58	32
Atmos. dry bulb, °F	102	~65	37

Plant Operating Data

Table B-131
Plant Operation–––Net MWh's––2006

Month	Unit				Plant
	5	6	7	8	
Jan	0	0	0	0	0
Feb	1,820	2,050	0	0	3,870
Mar	420	1,750	120	0	2,290
Apr	3,870	4,710	126,911	0	135,491
May	1,010	0	17,612	14,552	33,174
Jun	3,390	1,330	16,606	78,534	99,860
Jul	11,980	15,230	125,722	119,578	272,510
Aug	1,080	980	0	15,006	17,066
Sep	1,570	530	1,234	15,858	19,192
Oct	0	0	0	0	0
Nov	1,340	90	0	0	1,430
Dec	0	300	0	0	300

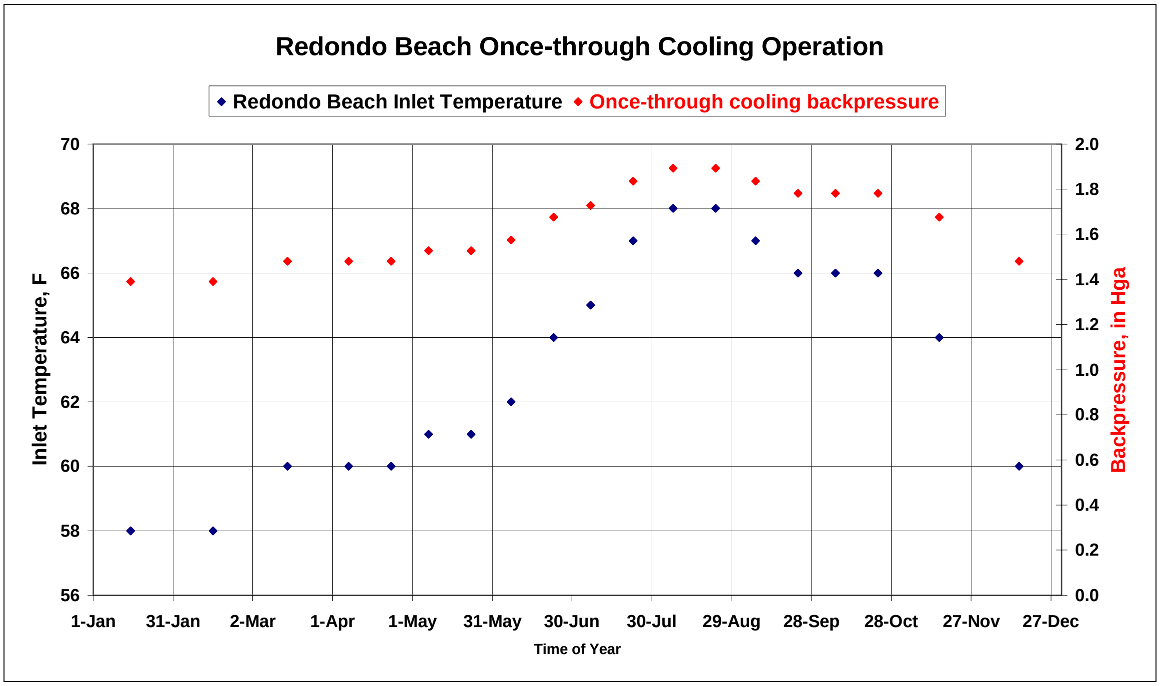


Figure B-101
Redondo Beach Once-through Operating Profile––Full Load

Cooling Tower Assumptions/Design

Wet cooling system design specs for all units

- Tower type: mechanical draft, counterflow, FRP construction
- Make-up water source: Sea water; 35,000 ppm salinity
- Operating cycles of concentration: n = 1.5

Table B-132
Cooling Tower Water Balance Specifications

Unit	Evaporation gpm	Make-up gpm	Blowdown gpm
5	1,750	5,250	3,500
6	1,750	5,250	3,500
7	4,800	14,400	9,600
8	4,800	14,400	9,600

Tower design conditions are for all circulating water flows and condenser specifications unchanged, an assumed tower approach of 10°F and a peak wet bulb temperature of 73°F.

Table B-133
Cooling Tower Design Conditions for Full Load on Hot Day

Unit	Ambient Wet Bulb	Range	Approach	TTD	Tcond	Backpressure
	F	F	F	F	F	in Hga
5	73	24.3	10	7	114.3	~ 2.95
6	73	24.3	10	7	114.3	~ 2.95
7	73	20.5	10	7	110.5	~ 2.65
8	73	20.5	10	7	110.5	~ 2.65

Therefore, on the hottest day at full load, all units would operate at backpressures in the range of 2.65 to 2.95 in Hga. Over the course of the year when the ambient wet bulb temperature would be lower, The backpressure would vary as indicated in the following figure. A comparison is given to the backpressure estimated with once-through cooling and indicates that the backpressure would normally be elevated by 0.5 to 1. in Hga.

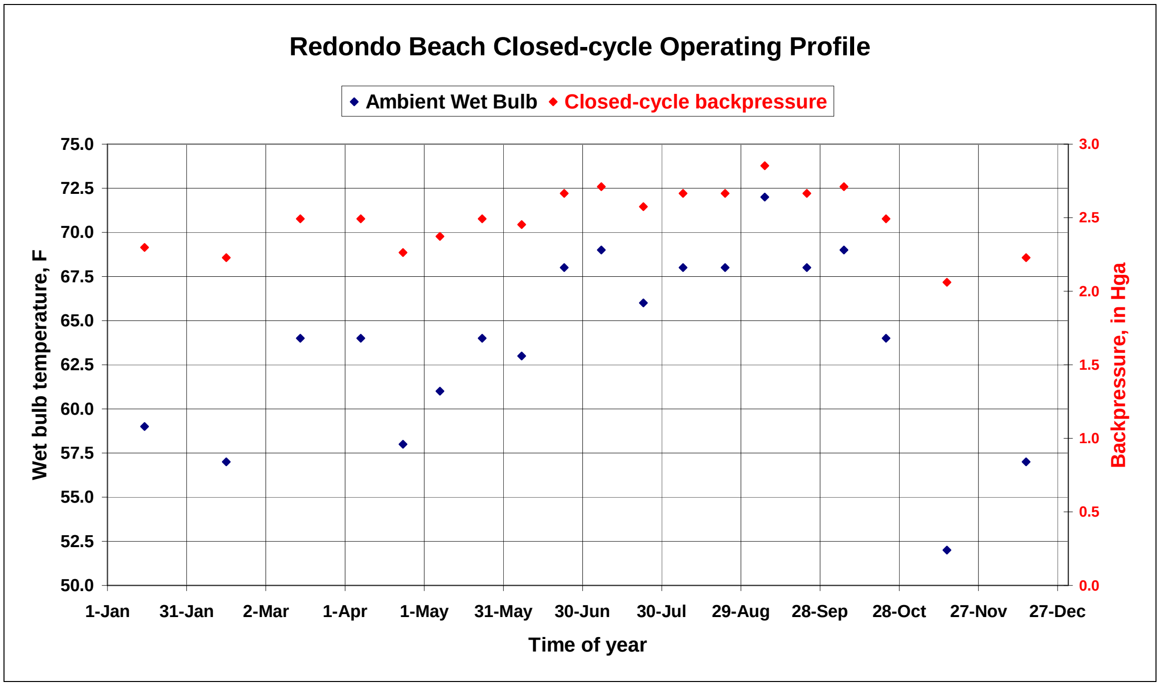


Figure B-102
Backpressure Comparisons

Wet Retrofit Costs

Table B-134
S&W Cost Estimates

S&W Costs---escalated to 2007; x 1.07 for seawater					
Unit	**Labor**	**Material**	**Equipment**	**Indirect**	**Total**
5	$5,036,000	$2,935,000	$4,997,000	$7,522,000	$20,491,000
6	$5,036,000	$2,935,000	$4,997,000	$7,522,000	$20,491,000
7	$13,483,000	$9,007,000	$15,436,000	$21,997,000	$59,923,000
8	$13,483,000	$9,007,000	$15,436,000	$21,997,000	$59,923,000
Plant Total	$37,038,000	$23,884,000	$40,866,000	$59,038,000	$160,828,000

Table B-135
Maulbetsch Consulting Survey Estimates

Maulbetsch Consulting Survey; escalated to 2007 $; x 1.07 for salinity			
Unit	**Easy**	**Average**	**Difficult**
5	$11,849,000	$19,748,000	$30,519,000
6	$11,849,000	$19,748,000	$30,519,000
7	$38,582,000	$64,304,000	$99,378,000
8	$38,582,000	$64,304,000	$99,378,000
Plant Total	$100,862,000	$168,104,000	$259,794,000

Dry Cooling

Similar cost estimates can be made for a dry cooling retrofit. The basic assumption is that for plants with low capacity factors, they must be available to produce close to full load on the hottest days of the year when the system load is at its peak. Therefore,

- Direct dry cooling: forced, mechanical-draft air-cooled condenser
- Steam flow: Units 5 and 6 ~ 921,000 lb/hr

  Units 7 and 8 ~ 2,526,000 lb/hr
- Design dry bulb: 100°F (mid-way between 0.4% dry bulb and median of extreme highs)
- Design turbine exhaust pressure: 4.5 in Hga (based on assumption that turbines of this age and design trip at 5 in Hga and that the plant would not wish to reduce output on the hottest days)
- Corresponding condensing temperature: 130°F

Therefore, ACC design ITD ($T_{condensing}$ - $T_{design\ ambient}$) = 130°F – 100°F = **30°F**

Dry Cooling Retrofit Costs

AC costs can be roughly estimated from EPRI Report No. 1005358; "Comparison of Alternate Cooling Technologies for U.S. Power Plants", August, 2004.

Vendor information for a design of:

Steam flow: 921,000 lb/hr (Units 5 and 6)
2,526,000 lb/hr (Units 7 and 8)

ITD: 30°F
Price: 2007 $

Table B-136
Dry Cooling Retrofit Cost Estimates—Units 5 and 6

Source/Basis	Equipment	Erection	Electrical	Duct Work	Indirect	Total	Cells
Vendor 1	$18,698,000	$8,002,000	$1,225,000	$122,000	$16,196,000	$44,242,000	50
Vendor 2	$19,596,000	$8,410,000	$980,000	$122,000	$16,812,000	$45,919,000	40
Vendor 3	$16,003,000	$7,838,000	$980,000	$122,000	$14,396,000	$39,340,000	40
Average	$18,099,000	$8,083,000	$1,061,000	$122,000	$15,802,000	$43,167,000	45
Scaled to 2007 $	$24,220,000	$9,627,000	$1,421,000	$164,000	$20,456,000	$55,887,000	

Table B-137
Dry Cooling Retrofit Cost Estimates—Units 7 and 8

Source/Basis	Equipment	Erection	Electrical	Duct Work	Indirect	Total	Cells
Vendor 1	$51,845,000	$22,188,000	$3,397,000	$338,000	$44,908,000	$122,673,000	50
Vendor 2	$54,335,000	$23,319,000	$2,717,000	$338,000	$46,616,000	$127,323,000	40
Vendor 3	$44,373,000	$21,733,000	$2,717,000	$338,000	$39,917,000	$109,081,000	40
Average	$50,184,000	$22,412,000	$2,942,000	$338,000	$43,815,000	$119,692,000	45
Scaled to 2007 $	$67,157,000	$26,694,000	$3,940,000	$455,000	$56,720,000	$154,962,000	

Effect on Plant Performance

A retrofitted cooling system of either the wet or dry type would have a deleterious effect on the plant net heat rate. This arises from two effects:

1. Considering only the wet system, the power requirements will be higher than the current pumping power requirements for the once-through system. This power is used for the additional circulating pumps and for the cooling tower fans and represents power that must be generated but cannot be sold.
2. The plant will operate at a higher backpressure and therefore a higher heat rate with closed cycle cooling. This effect will be much more pronounced for a dry system than for a wet system.

The additional power requirements are estimated as follows:

Pumping power: As noted in Section 4.1.3, the existing circulating water system will discharge into a sump from which a second set of pumps will draw the water and discharge it to the top of the cooling tower. The circulating water flow rate must be pumped through an additional head rise. This will be estimated at 40 feet to account for the lift out of the sump, the rise to the hot water distribution deck on the top of the tower and the head loss through the circulating water lines. A combined pump/motor efficiency of 75% is assumed. Each of these factors would be refined in a detailed analysis, but these are considered adequate to give a reasonable estimate of the effect of additional operating power on the plant. For the several units at Redondo Beach:

Table B-138
Redondo Beach Units: Retrofit Additional Pumping Power

Unit	Flow	Head	Eff	Power	Motor
	gpm	ft		kW	MW
5	72,000	40	0.75	542.3	0.72
6	72,000	40	0.75	542.3	0.72
7	234,000	40	0.75	1762.6	2.35
8	234,000	40	0.75	1762.6	2.35

Fan power: Similarly cooling tower fan power can be roughly estimated. It is assumed for retrofits on older, lower capacity factor units, the tower would be sized to “low first cost” design since the number of operating hours is low and power penalties are less severe. This is consistent with the assumptions made in the retrofit capital cost estimates. The number of cells will be estimated as one cell per 10,000 gpm of circulating water flow, the fan horsepower at 200 HP and a motor efficiency of 90%. For the Redondo Beach units this results in:

Table B-139
Redondo Beach Units: Retrofit Fan Power

Unit	Flow	Cells	Eff	Power	Motor
	gpm	n		hp	kW
5	72,000	7	0.9	1,400	1,160
6	72,000	7	0.9	1,400	1,160
7	234,000	23	0.9	4,600	3,813
8	234,000	23	0.9	4,600	3,813

This represents a combined, full-load operating power requirement of approximately 16.3 MW or approximately 1.25% of the plant power rating of 1,310 MW. The actual annual cost will obviously depend on the capacity factor, the number of hours on-line, and whether some fans are turned off when operating at part load. Also, the cooling system was sized for full load at acceptable backpressures at so-called “1%” ambient conditions, it would be well oversized for nearly the entire year. Therefore, the effect of requiring additional operating power for the pumps and fans coupled with operation at higher heat rate would be an increase in the fuel burned rather than a reduction in plant output.

Heat rate penalty: As seen in the earlier plot of comparative backpressures, the condensing pressure with closed-cycle wet cooling will run typically 0.5 to 1.0 in Hga higher than it would with once-through ocean cooling and increases to about 2.95 in Hga on the hottest days. The effect is less at part load. No information is available to estimate the effect on heat rate resulting from the increased backpressure. However, information from comparable units suggest an increase of at least 0.25% for each 0.1 in Hga increase in backpressure above design might be reasonable. The comparative plot shown earlier suggests that closed cycle cooling will result in increased backpressure throughout the year ranging from 0.5 to 1. in Hga with a corresponding heat rate penalty of 0.5 to 1.%. In the absence of other information, it is assumed to be applicable to the Redondo Beach units as well resulting in a heat rate penalty at full load of 0.5 to 1.% for the units at the plant. It should be noted that some estimates on other individual units of similar size and age have been much higher, up to a heat rate increase of as much as 1,000 Btu/kWh for a backpressure increase of 1.5 to 2.5 in Hga..

Capacity Limits

The increased back pressure will likely results in an output restriction at the hottest day. The magnitude of the shortfall will depend on the operating philosophy. If the firing rate is held constant, a 1% heat rate penalty would correspond to roughly a 1% reduction in output which would appear to be a minor effect on output. If, however, it were to be decided that operation at a backpressure of 2.95 in Hga constituted an unacceptable maintenance risk to the turbine, then the firing rate would need to be reduced to hold whatever backpressure was consider acceptable. Information to estimate what the shortfall would be in that case is not available but presumably could be estimated by plant staff based on the information given above.

Maintenance Costs

Commonly used factors for maintenance (labor, materials, chemicals, etc.) for wet cooling systems range from 2. to 3. % of the system capital costs.

For wet systems, the important costs are for water treatment, biofouling control and keeping the basin clean. Using salt water and having salt drift around the plant would require rust control, extra painting, etc. Using the high end of typical factors, assume 3. to 3.5% of the capital cost of the tower. It is unclear how AES would allocate these costs between operation and maintenance, but an estimate of 3% of the “average” capital costs for all units of $170 million could amount to approximately $5,000,000 per year.

Additional Cost Considerations

Although the S&W costs are pretty close to the Maulbetsch Consulting survey’s “Average” difficulty estimate, neither of those estimates can account for any site-specific difficulties which might be encountered at the Redondo Beach site. Those items that could cause a retrofit at this site to be in a different, either “Difficult” or “Easy” category include:

- Difficulty in locating the tower
- Unusual site preparation costs
- Significant interferences to the cost of installation of the circulating water lines
- The need for cooling tower plume abatement
- Stringent noise control
- The use of an alternate make-up water

Location of Tower/Unusual Site Preparation Costs/Interferences

It appears that space would be available either to the east or south of the plant if what appear to be unused fuel tanks were removed. (See site photo at beginning of write-up)

No information is available regarding the suitability of these sites, but a number of items would need to be considered:

i. The need to demolish, relocate and rebuild existing structures, including the fuel tanks, for some locations.

ii. Unstable soil conditions requiring significant foundation work such as deep pilings to stabilize the towers. This is likely given the location of the plant.

iii. Drift deposition from salt water towers.

iv. Underground infrastructure which would make the installation of underground circulating water lines difficult and costly.

v. Remoteness of current intake bays from towers south or east of the plant and difficulty in tying into the existing circulating water system.

vi. Possible neighborhood objections to visible plumes, corrosive drift and noise.

vii. The need for PM10 offsets for expected drift from seawater towers.

Plume Abatement

Based on the view in the aerial photo of the neighboring area, it appears that a visible plume could be a serious issue at this site primarily from an aesthetic viewpoint. It is reasonable to assume that a plume abatement tower would be required. Plume abatement towers have an air-cooled section on top of the wet tower. The hot water is pumped to the top of the tower, passes down through the dry section and then discharged onto the hot water distribution deck of the wet section. The air passing across the finned tubes of the dry section mixes with the wet plume coming off the wet section and keeps it from becoming saturated and condensing in the cold atmosphere. The need for a plume abatement tower would increase both the capital cost of the tower itself by a factor of perhaps 2. to 2.5 and the additional pumping power by an additional 30 to 50% due to the greater height to which the hot water must be pumped.

Aesthetics

In addition to any issues with a visual plume, the simple appearance of a cooling tower is sometimes considered an aesthetic affront. In this instance, even though the towers would be visible to neighbors, considering the number, size and bulk of the plant buildings already present, it does not appear that this would present a major problem.

Noise Control

Noise from wet cooling towers comes both from the fans and from the water cascading through the fill. Fan noise can be diminished by fan design or the reduction in air velocity which sometime requires the use of bigger, or more, cells. The water noise is more difficult to reduce and usually requires the construction of sound barriers around the cooling tower. As in the case of the plume abatement question, the aerial photo of the plant and the neighboring area makes it appear that cooling tower noise might be of some concern. In case that it is, the capital cost of the tower itself cost might increase from 20 to 40%.

Alternate Sources of Make-Up Water

The use of seawater make-up can introduce intractable problems regarding drift and related maintenance considerations. (See later discussion of drift and PM10.) An alternative can be to purchase reclaimed water from nearby municipal water treatment facilities. No information is available to assess the possibility of this approach.

If, however, possibility of using reclaimed water for wet cooling tower makeup were to be considered, the distance of sources from the plant, the expected very high cost of installing delivery and return pipelines to the remote sources and the expected extended time required to obtain permits will be important factors in determining the cost.

Shutdown Period

There is often concern over the period of lost plant availability during the retrofit construction period. In this instance, it appears that the major part of the construction could be done while the plant is on-line, with shutdown required only for the final tie-in of the circulating water lines to the existing water circuit. There is no information available to estimate how long this might be. However, the operating profiles shown earlier for 2005 indicate periods of little or no operation. Therefore, it appears that the tie-in could be accomplished with no serious downtime.

Other Environmental Issues

Retrofit to a closed-cycle cooling system introduces some environmental issues which a once-through cooling system does not. These are increased air emissions from the stack and drift from the cooling tower.

Stack Emissions

In an earlier section it was noted that a closed-cycle retrofit increase the unit net output because of heat rate penalties and the use of increased operating power. In this instance these together were estimated at from 1 to 2%. Therefore, the delivery of the same amount of electric power to the grid will require the burning of additional fuel at some location to make up that lost at Redondo Beach. Based on the unit heat rate information provided, this does not appear to be major effect in this case. Furthermore, in the discussion of this issue in Chapter 7, it was pointed out that the effect of making up this shortfall was highly variable depending on how and where the replacement per was generated. Therefore, no attempt is made to asses the effect in quantitative terms beyond pointing out that reliable estimates of the shortfall to be expected from full load operation can be made. Given the urban location of this facility air permitting issues could be especially problematic.

Drift

It is assumed that any cooling tower would be equipped with state-of-the-art drift eliminators rated at about 0.0005% of circulating water flow. The following table estimates the amount of drift to be expected from such designs. In addition, as discussed earlier, Federal EPA and State regulations characterize all solids carried off in cooling tower drift as PM10. The cost of offsetting this amount, should it be necessary will vary considerably from site to site as will the severity of the regulatory constraints.

Table B-140
Redondo Beach Drift Estimates

Unit	Flow gpm	Drift[1] gpm	Drift lb/hr	PM10 lb/hr	PM10 tons/year[2]	Cap. Factor %	PM10 tons/year[3]
5	**72,000**	0.36	180	9.00	39.4	**24.7**	**9.7**
6	**72,000**	0.36	180	9.00	39.4	**25.7**	**10.1**
7	**234,000**	1.17	585	29.24	128.1	**26.7**	**34.2**
8	**234,000**	1.17	585	29.24	128.1	**27.7**	**35.5**

1. At drift eliminator efficiency of 0.0005%
2. Assumes full load all year
3. At 2006 capacity factor

General Conclusion

On balance, it is concluded that the nature of the likely problems and additional costs to be encountered at Redondo Beach would put the retrofit at this site in the “average” to “difficult” category. Based on the results from the Maulbetsch Consulting survey presented above, this would put the project cost in the range of $200. million. Given the very low capacity factors for all units, particularly for Units 5 and 6, an investment of this size in retrofit would seem highly problematic.

B.15 San Onofre Nuclear Power Station (Southern California Edison)

Location

5000 Pacific Coast Highway
San Clemente, California 92672
33° 22' 12.95" N; 117° 33' 17.11" W
Contact: Patrick Tennant, 626-302-3066

Figure B-103
San Onofre Nuclear Power Station Boundaries and Neighborhood

Figure B-104
San Onofre Nuclear Power Station Site View

Plant/Site Information

Unit 2: 1127 MW
Unit 3: 1127 MW

Table B-141
San Onofre Cooling System Operating Conditions

Unit	MW	Cooling Water flow		Steam flow	Heat duty	Tin	Tex	Range	Tcond	TTD	Backpressure
		gpm	cfs	lb/hr	Btu/hr	F	F	F	F	F	in Hga
2	**1127**	795,600	1770	8.368E+06	7.950E+09	64.0	83.0	19.0	103.0	20.0	2.10
3	**1127**	795,600	1770	8.368E+06	7.950E+09	64.0	83.0	19.0	103.0	20.0	2.10

Table B-142
San Onofre Capacity Factors

Unit	MW (net)	Capacity Factor (%)						
		2001	2002	2003	2004	2005	2006	Average
2	**1127**	96.1%	86.1%	98.4%	81.6%	90.5%	68.4%	**85%**
3	**1127**	57.2%	96.7%	87.1%	70.7%	95.9%	69.0%	**84%**

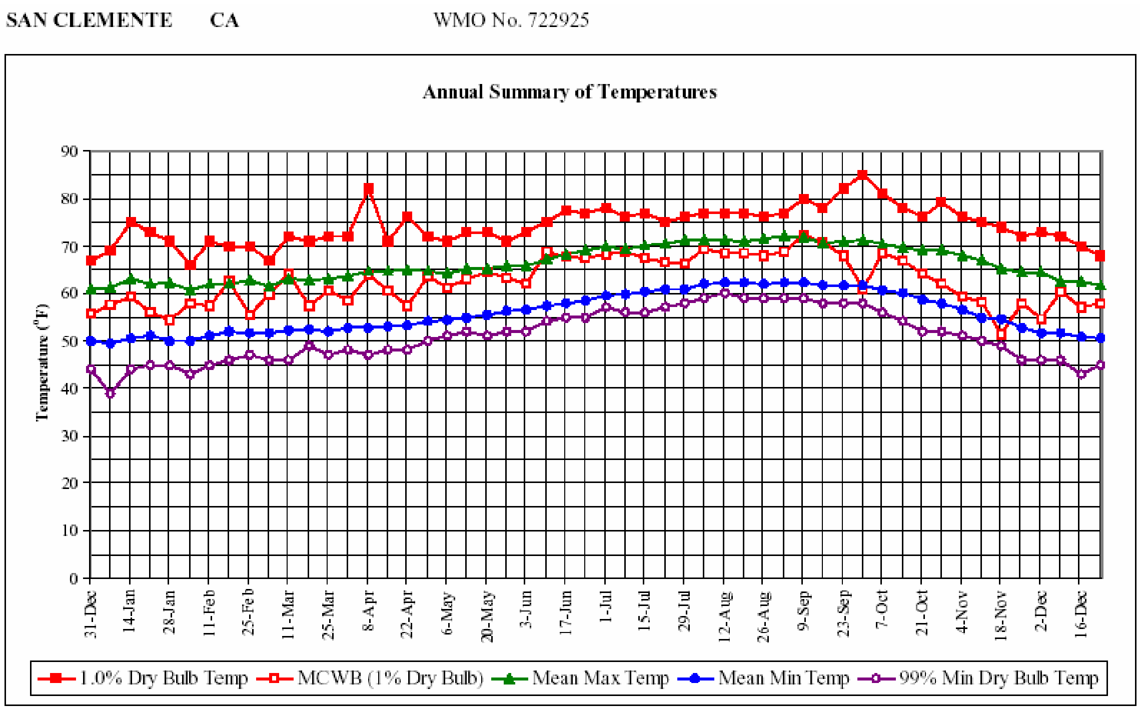


Figure B-105
San Onofre Meteorological Data

Table B-143
San Onofre Meteorological Data

Temperature	Max.	Average	Min.
San Onofre inlet temp., °F	68	62	57
Atmos. wet bulb, °F	73	57	40
Atmos. dry bulb, °F	87	73	41

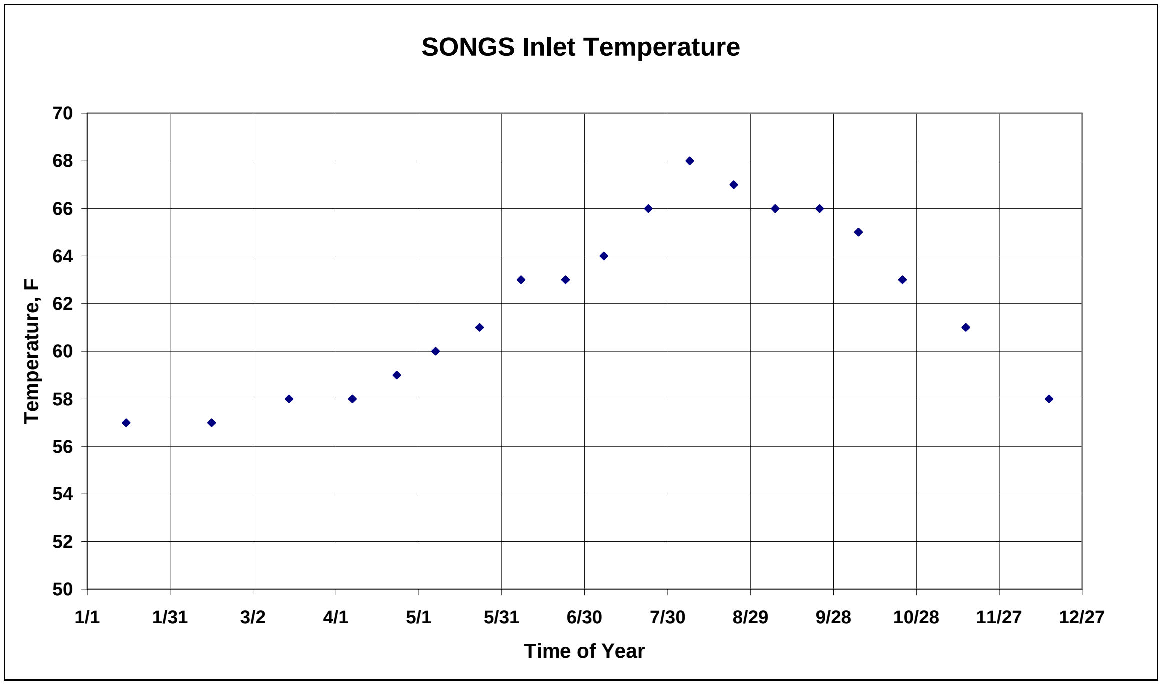


Figure B-106
San Onofre Ocean Temperature

Plant Operating Data

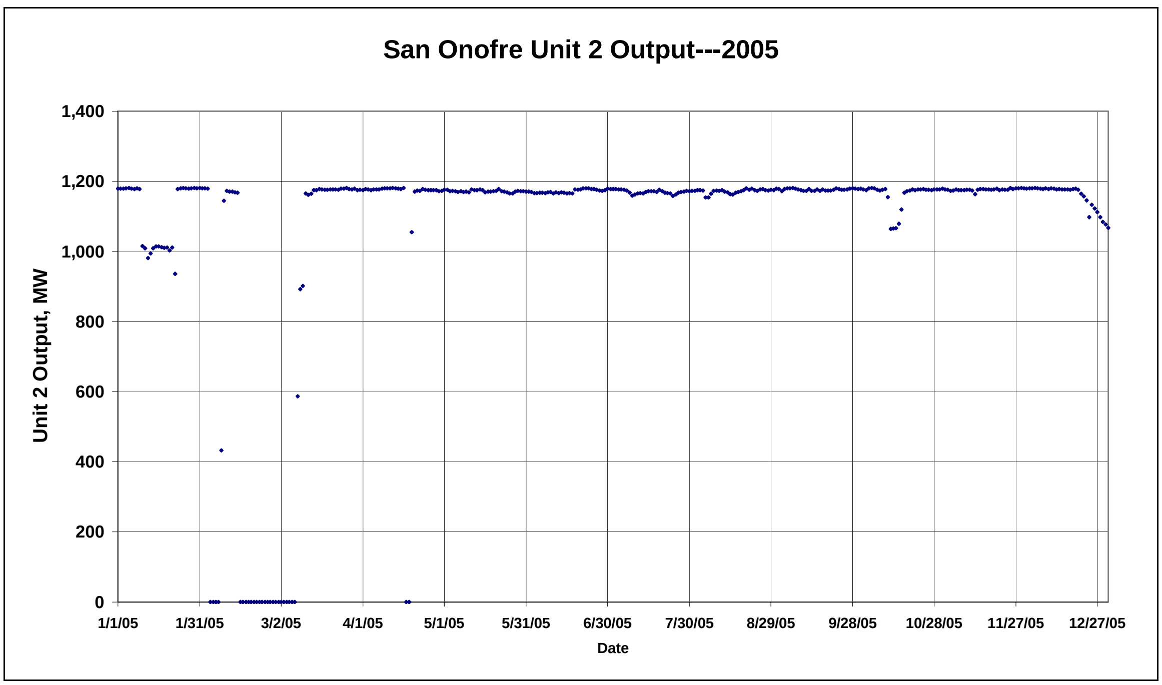


Figure B-107
San Onofre Unit 2 Output––2005

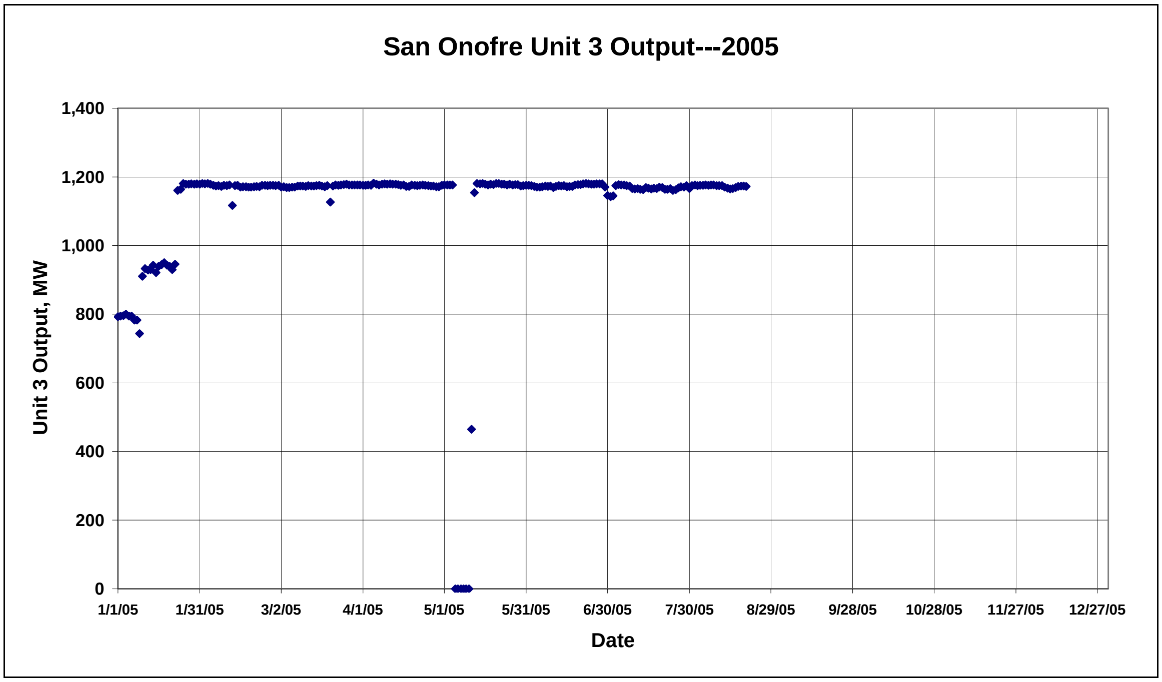


Figure B-108
San Onofre Unit 3 Output––2005

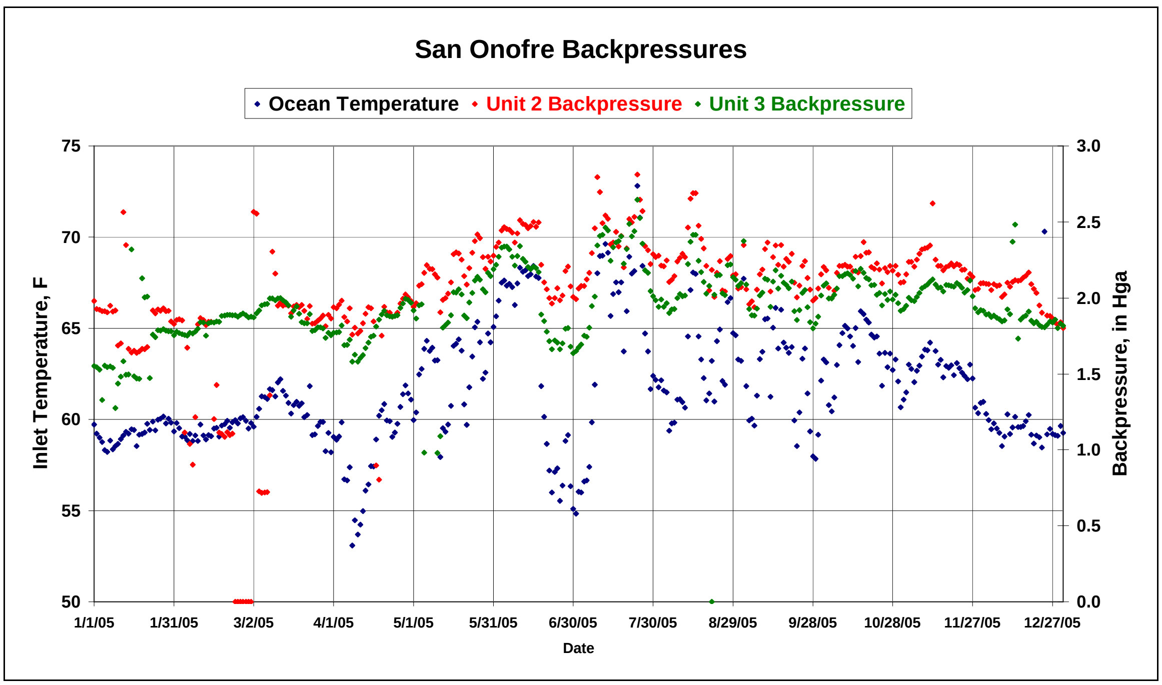


Figure B-109
San Onofre Backpressure (Once-Through Cooling)

Cooling Tower Assumptions/Design

- Tower type: mechanical draft, counterflow, FRP construction
- Make-up water source: Sea water; 35,000 ppm salinity
- Operating cycles of concentration: n = 1.5
- Evaporation rate: Units 2 and 3---~ 17,000 gpm each
- Make-up rate (@ n = 1.5): Units 2 and 3---~ 51,000 gpm each
- Blowdown (@ n = 1.5): Units 2 and 3---~ 34,000 gpm each

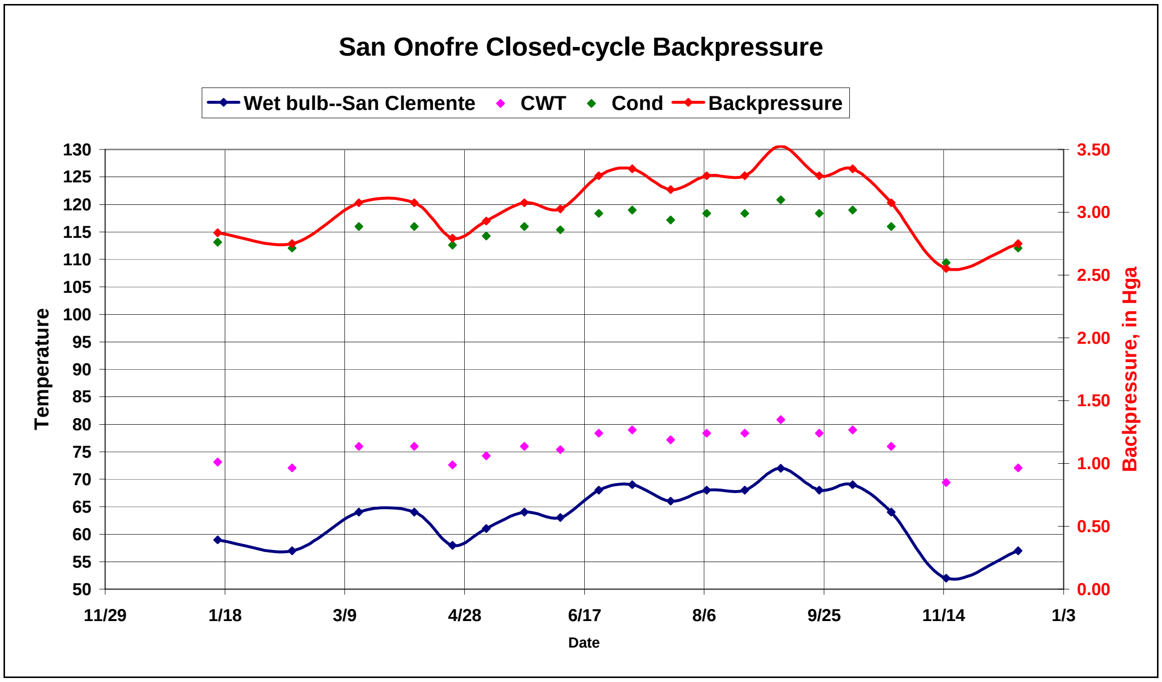


Figure B-110
Backpressure Comparisons-Full Load for Year

Wet Retrofit Costs

Table B-144
S&W Cost Estimates

S&W Costs---escalated to 2007; x 1.07 for seawater					
Unit	Labor	Material	Equipment	Indirect	Total
2	$43,551,000	$16,496,000	$34,280,000	$54,709,000	$149,036,000
3	$43,551,000	$16,496,000	$34,280,000	$54,709,000	$149,036,000
Plant Total	$87,102,000	$32,992,000	$68,560,000	$109,418,000	$298,072,000

Table B-145
Maulbetsch Consulting Survey Estimates

Maulbetsch Consulting Survey; escalated to 2007 $; x 1.07 for salinity			
Unit	**Easy**	**Average**	**Difficult**
2	**$131,298,000**	**$218,830,000**	**$338,192,000**
3	**$131,298,000**	**$218,830,000**	**$338,192,000**
Plant Total	**$262,596,000**	**$437,660,000**	**$676,384,000**

This site is the one instance where the agreement between the S&W estimate and the "average" estimate from the survey is poor. The S&W estimate for this case is much closer to the "easy" category. While there is no provable explanation for this difference, it must stem from the fact that the large nuclear station that S&W used for the reference case, from which the San Onofre estimate was scaled, was a relatively easy situation for retrofit.

Independent Case Study

An independent estimate of the wet cooling retrofit cost is available from a study performed by PLG, Inc. (formerly Pickard, Lowe and Garrick) for Southern California Edison in August, 1990. The capital cost of the wet system for Units 2 and 3 was estimated at $172 million in 1990$. Escalating this to 2007$ at 3% per year, yields an estimate of $284 million in current dollars. If "Indirects" are added in the same proportion as was used in the S&W study, the comparable estimated project cost is approximately $450 million which is in reasonable agreement with the "average" difficulty estimate from the survey.

There are some differences in the operating parameters for the towers in PLG analysis than are generally used in this study. For example, the evaporation rate seems much lower than would be expected and the chosen approach of 8 ºF seems low for the site meteorology. However, with the exception of the approach temperature, all the major variables affecting the cost are reasonably consistent.

Dry Cooling

Dry cooling estimates will not be made for a nuclear plant. There have never been any nuclear plants equipped with direct dry cooling (using an air-cooled condenser) in the U.S. It has not been determined whether such a configuration could be permitted if proposed. While an indirect dry cooling system could likely be permitted, the additional temperature rise associated with the condenser range in addition to the ITD of an air-cooled heat exchanger would raise the achievable backpressure well above reasonable operating limits.

For an ambient design dry bulb temperature of 90°F, an ITD of 20°F and the existing range plus TTD of 40°F, the condensing temperature would be approximately 150°F corresponding to a backpressure of 7.5 in Hga. Furthermore, even if elaborate turbine modifications were made to accommodate the dry cooled system, it would be of a type and size for which no reasonable cost estimates can be made at this time.

At the present time, there are some proposed nuclear plants in the Eastern U.S. which are considering the use of hybrid (wet/dry) cooling systems, consisting of a fin-fan air-cooled heat exchanger in series with a wet or wet/dry tower. At least one plant with a system of this type operates in Germany. However, any estimate of the cost or performance of such a system would be highly speculative since there is no experience or even literature information to assist in bracketing the costs of air-cooled exchangers (not air-cooled condensers) of this size and type of service and it is not addressed further in this report.

Effect on Plant Performance

A retrofitted cooling system of either the wet or dry type would have a deleterious effect on the plant net heat rate. This arises from two effects:

1. Considering only the wet system, the power requirements will be higher than the current pumping power requirements for the once-through system. This power is used for the additional circulating pumps and for the cooling tower fans and represents power that must be generated but cannot be sold.
2. The plant will operate at a higher backpressure and therefore a higher heat rate with closed cycle cooling. This effect will be much more pronounced for a dry system than for a wet system.

The additional power requirements are estimated as follows:

Pumping power: The circulating water flow rate must be pumped through an additional head rise. At the locations where the tower must be placed, there is significant elevation relative to the location of the plant buildings. Plant estimates suggest that a total head rise of 100 feet will be required to account for this grade elevation in addition to the 40 feet to account for the lift out of the sump, the rise to the hot water distribution deck on the top of the tower and the head loss through the circulating water lines. A combined pump/motor efficiency of 75% is assumed. Each of these factors would be refined in a detailed analysis, but these are considered adequate to give a reasonable estimate of the effect of additional operating power on the plant. For the two units at San Onofre:

Table B-146
San Onofre Units: Retrofit Additional Pumping Power

Unit	Flow	Head	Eff	Power	Motor
	gpm	ft		kW	MW
2	811,000	100	0.75	15271.8	20.36
3	811,000	100	0.75	15271.8	20.36

Fan power: Similarly cooling tower fan power can be roughly estimated. It is assumed for retrofits on older, lower capacity factor units, the tower would be sized to “low first cost” design since the number of operating hours is low and power penalties are less severe. This is consistent with the assumptions made in the retrofit capital cost estimates. The number of cells will be estimated as one cell per 10,000 gpm of circulating water flow, the fan horsepower at 200 HP and a motor efficiency of 90%. For the San Onofre units, this results in:

Table B-147
San Onofre Units: Retrofit Fan Power

Unit	Flow	Cells	Eff	Power	Motor
	gpm	n		hp	kW
2	811,000	81	0.9	16,220	13,445
3	811,000	81	0.9	16,220	13,445

Note that the PLG analysis estimated 96 cells. This results from the lower approach temperature and the higher recirculation allowance, which gives a higher inlet, wet bulb temperature.

This represents a combined, full-load operating power requirement of approximately 67.5. MW or approximately 3 % of the plant power rating of 2,254 MW. The actual annual cost will obviously depend on the capacity factor, the number of hours on-line, and whether some fans are turned off when operating at part load. Also, the cooling system was sized for full load at acceptable backpressures at so-called “1%” ambient conditions; it would be well oversized for nearly the entire year. Therefore, the effect of requiring additional operating power for the pumps and fans coupled with operation at higher heat rate would be an increase in the reactor power rather than a reduction in plant output.

Heat rate penalty: As can be seen by comparing the annual variation in backpressure plotted for both once-through cooling and for closed-cycle wet cooling in earlier plots, the condensing pressure with closed-cycle wet cooling will run typically 0.5 to 1.0 in Hga higher than it would with once-through ocean cooling and increases to about 3.5 in Hga on the hottest days. The effect is less at part load. The annual average effect if evaluated at the average wet bulb temperature of 57°F is approximately 0.25 in Hga. This is consistent with the conclusion reached in the PLG study. Based on turbine heat rate curves available to them at the time, this resulted in an average output reduction of about 1% (~ 12 MW per unit).

Capacity Limits

The increased backpressure will result in a higher output restriction on the hottest day. If the effect of an increased backpressure of ~ 1 in Hga is extrapolated from the information above, a shortfall of about 4% is expected, corresponding to approximately 100 MW for the plant. This, when added to the additional operating fan and pump power of 67.5 MW results in a total peak day shortfall of 168. MW or nearly 7.5 %.

Maintenance Costs

Commonly used factors for maintenance (labor, materials, chemicals, etc.) for wet cooling systems range from 2. to 3. % of the system capital costs.

For wet systems, the important costs are for water treatment, biofouling control and keeping the basin clean. Using salt water and having salt drift around the plant would require rust control, extra painting, etc. Using the high end of typical factors, assume 3. to 3.5% of the capital cost of the tower. It is unclear how SONGS would allocate these costs between operation and maintenance, but an estimate of 3% of the “average” capital costs for all units of $250 to 300 million could amount to approximately $8,000,000 per year.

Additional Cost Considerations

Although there is reasonable agreement between the estimated costs escalated from the PLG study and the "average" cost from the Maulbetsch Consulting survey, it is unclear that either of these estimates has captured all of the site-specific issues, which might lead to a higher cost. Some these considerations include:

- Difficulty in locating the tower
- Unusual site preparation costs
- Significant interferences to the cost of installation of the circulating water lines
- The need for cooling tower plume abatement
- Stringent noise control
- The use of an alternate make-up water

Location of Tower/Unusual Site Preparation Costs/Interferences:

It does not appear, from examining the aerial photos at the beginning of this write-up and some site plans made available for the study, that there is anyplace to site these large (~ 40 cell) cooling towers other than at the far ends of the property. As indicated in the figure below, all open land on the existing site is either protected area, state park land, is used for storage of materials, which cannot be stored elsewhere, or needed for traffic control to maintain compliance with safety requirements. Relocation of the parking area would require shuttling of employees and contractors to a distant location across the highway.

Locating the towers at the far ends of the property would require the installation of 4,000 feet of large (~ 20 foot diameter) for each tower. At a nominal cost of $11/foot length/inch diameter, the cost is at least $20 million assuming no interferences. This is significantly higher than the escalated cost for this item from the PLG report suggesting that shorter runs were assumed or lower (real dollar) costs for installation. In any case, there was clearly no allowance for the presence of interferences in the vicinity of the plant.

There is no information available to assess the possibility of unfavorable soil conditions, which could require extraordinary measures to stabilize the foundations for the towers. However, on "near coastal" cliffs this is a possibility, which would need to be considered in advance of committing to any tower location.

Figure B-111
Conflicting Area Uses

Other Installation Constraints

The location and configuration of the intake area severely restricts the ability to locate an intermediate sump and the new circulating water pumps and motors.

Plume Abatement

Based on the view in the aerial photo of the neighboring area, it appears that a visible plume could be a serious issue at this site. This stems from safety concerns on I-5, which runs within 0.15 miles of the plant along the eastern boundary; from the possible effects on Marine air operations to the south, and from aesthetic sensitivity of the beach area.

It is reasonable to assume that a plume abatement tower would be required. Plume abatement towers have an air-cooled section on top of the wet tower. The hot water is pumped to the top of the tower, passes down through the dry section and then discharged onto the hot water distribution deck of the wet section. The air passing across the finned tubes of the dry section mixes with the wet plume coming off the wet section and keeps it from becoming saturated and condensing in the cold atmosphere. The need for a plume abatement tower would increase both the capital cost of the tower itself by a factor of perhaps 2. To 2.5 and the additional pumping power by an additional 30 to 50% due to the greater height to which the hot water must be pumped.

Aesthetics

In addition to any issues with a visual plume, the simple appearance of a cooling tower is sometimes considered an aesthetic affront. In this instance, the concern would be primarily the appearance of the towers from the beach and possibly from the residential areas (one to the east of I-5 located 1 to 1.5 miles to the north-northwest of the plant, another 2.5 to 3 miles to the north.). Considering the number, size and bulk of the plant buildings already present, this may not present a major problem. However, given the prevailing attitudes with regard to scenic issues on the coast and from recreational areas, it should be expected to be a contentious, time-consuming and costly issue.

Noise Control

Noise from wet cooling towers comes both from the fans and from the water cascading through the fill. Fan design or the reduction in air velocity, which sometime requires the use of bigger, or more, cells, can diminish fan noise. The water noise is more difficult to reduce and usually requires the construction of sound barriers around the cooling tower. It appears that cooling tower noise would not be a serious constraint based on the distance to residential areas. It may be that noise on the beach would be considered undesirable. An additional consideration is that the cliffs running west of the plant above the beach are a nesting habitat for the California coastal gnatcatcher, an endangered avian species. It might be argued that the noise would disrupt their nesting and breeding habits. On the other hand, the fact that highway noise from I-5 already exists may be a mitigating factor.

There is no information or experience available to this study to evaluate this issue, but it should be explored if a retrofit were undertaken. If noise abatement were required, the capital cost of the tower itself cost might increase from 20 to 40%.

Alternate Sources of Make-Up Water

The use of seawater make-up can introduce intractable problems regarding drift and related maintenance considerations. (See later discussion of drift and PM10.) An alternative can be to purchase reclaimed water from nearby municipal water treatment facilities.

In this instance, however, possibility of using reclaimed water for wet cooling tower makeup was considered and rejected due to the distance of sources from the plant, the expected very high cost of installing delivery and return pipelines to the remote sources and the expected extended time required to obtain permits even if the approach were deemed feasible.

Shutdown Period

There is often concern over the period of lost plant availability during the retrofit construction period. In this instance, it appears that the major part of the construction could be done while the plant is on-line, with shutdown required only for the final tie-in of the circulating water lines to the existing water circuit. There is no information available to estimate how long this might be.

Service Water System

The existing salt water “service water” system may require special attention since it represents an additional water intake (although not a cooing water intake under the normal 316 (b) definition and purview).

Other Environmental Issues

Retrofit to a closed-cycle cooling system introduces some environmental issues, which a once-through cooling system does not. These are increased air emissions from the stack and drift from the cooling tower.

Stack Emissions

It was estimated earlier that a capacity shortfall averaging 25 MW for the year and as much as 100 MW on the hottest days is to be expected. Therefore, the delivery of the same amount of electric power to the grid will require the burning of additional fuel at some location to make up that lost at San Onofre. Furthermore, in the discussion of this issue in Chapter 7, it was pointed out that the effect of making up this shortfall was highly variable depending on how and where the replacement power was generated. However, the capacity would almost surely be replaced with fossil generation since existing nuclear plants are already operating at high capacity factors and now ones cannot be rapidly installed. Therefore, the replacement power will come from units with air emissions that nuclear units do not have. No attempt is made to assess the effect in quantitative terms beyond pointing out that reliable estimates of the shortfall to be expected from full load operation can be made.

Drift

It is assumed that any cooling tower would be equipped with state-of-the-art drift eliminators rated at about 0.0005% of circulating water flow. The following table estimates the amount of drift to be expected from such designs. In addition, as discussed earlier, Federal EPA and State regulations characterize all solids carried off in cooling tower drift as PM10. The cost of offsetting this amount, should it be necessary will vary considerably from site to site as will the severity of the regulatory constraints.

Table B-148
San Onofre Drift Estimates

Unit	Flow	Drift[1]	Drift	PM10	PM10	Cap. Factor	PM10
	gpm	gpm	lb/hr	lb/hr	tons/year[2]	%	tons/year[3]
2	**811,000**	4.06	2027	101.33	443.8	**68.4**	**303.6**
3	**811,000**	4.06	2027	101.33	443.8	**69.0**	**306.3**

1. At drift eliminator efficiency of 0.0005%
2. Assumes full load all year
3. At 2006 capacity factor

Permitting Issues

As noted earlier, the site is bounded by state parks, environmentally sensitive areas and is within the coastal zone requiring approvals from several agencies. Since San Onofre is a nuclear plant, the NRC has jurisdiction over all aspects of any plant redesign and operational modification. Clearly, the permitting process will be more than normally complex, lengthy and costly with the many different agencies involved.

Changes in discharge from once-through cooling to closed cycle blowdown may require modifications to both NPDES and NRC discharge permits. Treated sewage discharge is not combined with cooing water discharge. Any chemical addition for befouling control of the intake and discharge tunnels or the tower fill would need to be considered in permits.

Special Considerations

Re-Optimization

It should be noted that all of the discussion so far has been based on the generic assumption made for this study that the existing circulating water system would be left in its existing operating state; that is, the condenser, the existing circulating water flowrate and the existing circulating water pumps themselves would be unchanged. The additional pumping power required to lift the water to the top of the towers and to pump them through the new circulating water lines would be supplied with a new set of pumps and the connection between the two circuits would be accomplished through existing intake and discharge bays or with a newly installed sump from which water to the towers is drawn. These assumptions are reasonable and appropriate for smaller, older plants with lower capacity factors and limited remaining life. They are likely not appropriate for San Onofre with a high capacity factor and a long expected remaining life.

In such circumstances, it would be economically preferred to re-optimize the cooling system to a configuration appropriate for closed-cycle wet cooling. Specifically, it is well known that closed-cycle systems optimize at lower circulating flowrates and higher condenser ranges than do once-through cooling systems.

Such a system will require somewhat larger towers but will operate at lower auxiliary power and provide better cooling and result in significantly lower total evaluated costs over the remaining life the plant. Such a conversion would involve a redesign and replacement of the condensers to operate at the lower flow rates (likely a change from single to two-pass configuration) with the likely requirement for extensive rearrangement of the massive piping into and out of the waterboxes and the opening up of the building structure around the condensers to accommodate the modifications.

If condenser modifications are required, the location of the condensers at 23 feet below grade would require extensive demolition and excavation to gain access. This would not only add to the cost but would greatly extend any required outage period for the retrofit to 6 to 12 months based on plant staff estimates. This is in comparison to a normal refueling outage of 30 to 40 days.

Even a cursory estimate of the cost of such massive modifications is well beyond the scope of this study. However, some guidance may be gained from the several studies conducted for Diablo Canyon as discussed in Section 6 of this report. It is noted that the S&W estimate was again well below the “average” survey result. However, two separate site studies were both well above the “difficult” survey result. The second of those studies, which attempted to account for the re-optimization, exceeded the “average” cost by nearly a factor of x3. It is noted that the PLG study did not capture these costs of re-optimization but rather estimated costs for an off-optimum system, as is the usual assumption in cooling system retrofit studies.

Security

If the cooling towers must be located on land outside of the existing security perimeter, as appears likely from the prior discussion of tower location, the additional area would have to be protected with additional fencing, guard towers and security staff. This would incur additional capital and operating costs in excess of average retrofit situations.

General Conclusion

It is difficult to capture the range of possible issues for a cooling system retrofit at San Onofre. If the existing circulating system is retained and the price of off-optimum cooling system performance is accepted, then the project cost would appear to be in the “average” to “difficult” range of perhaps $500 to $600 million. If the choice were made to re-optimize the system, it would likely exceed the “difficult” estimate of $675 million and perhaps significantly so.

B.16 Scattergood Generating Station (Los Angeles Department of Water and Power)

Location

12700 Vista del Mar
Playa del Rey, California 90293-8502
33° 55' 08.83" N; 118° 25' 23.22" W
Contact: Katherine Rubin, 213-367-0436

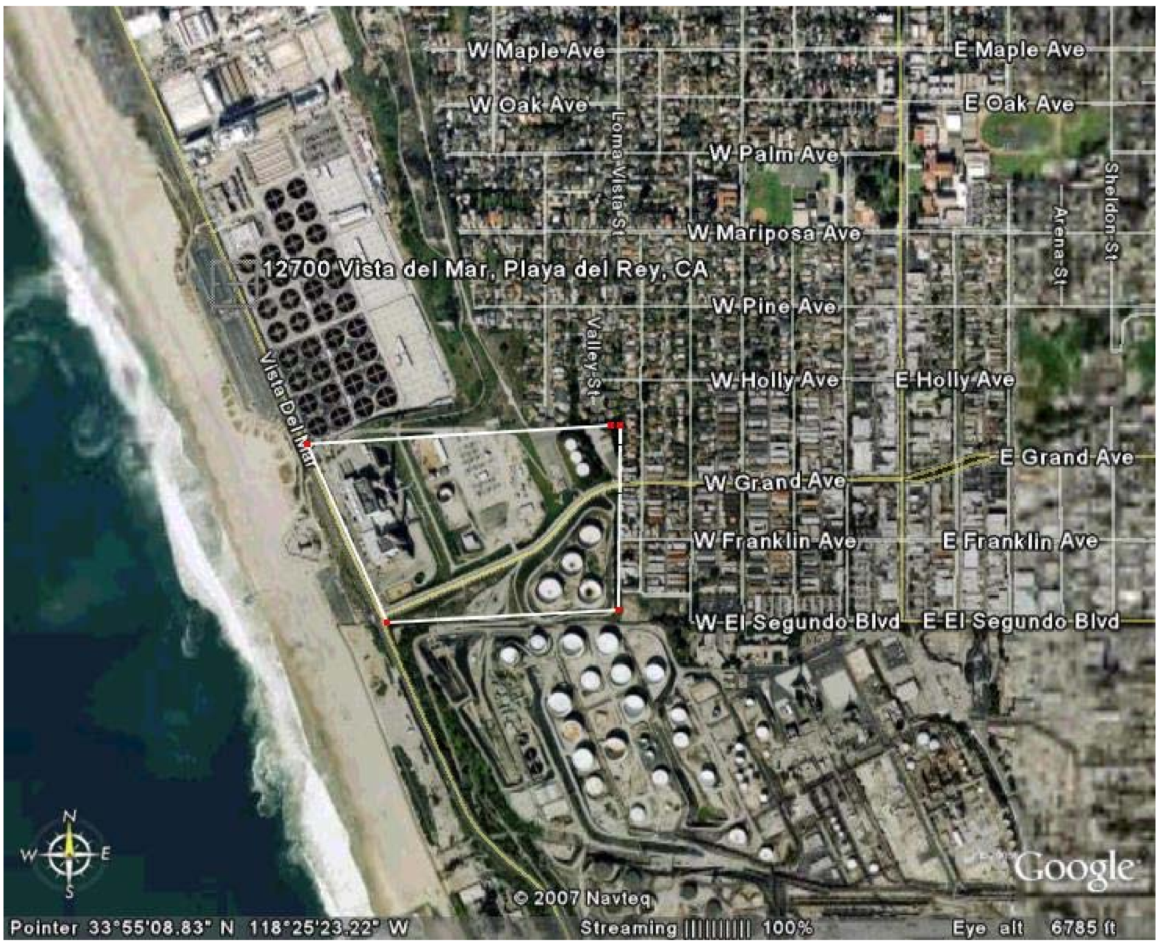


Figure B-113
Scattergood Generating Station: Boundaries and Neighborhood

Figure B-114
Scattergood and Surroundings

Figure B-115
Scattergood Generating Station: Site View

Plant/Site Information

Units 1 and 2: 179 MW oil/gas each
Unit 3: 460 MW gas

Table B-148
Scattergood Cooling System Operating Conditions

Unit	MW	Cooling Water flow		Steam flow	Heat duty	Tin	Tex	Range	Tcond	TTD	Backpressure
		gpm	cfs	lb/hr	Btu/hr	F	F	F	F	F	in Hga
1	189	78,000	174	1.200E+06	1.140E+09	60.0	89.2	29.2	102.2	13.0	2.10
2	189	78,000	174	1.200E+06	1.140E+09	60.0	89.2	29.2	102.2	13.0	2.10
3	460	188,000	419	2.980E+06	2.831E+09	60.0	90.1	30.1	103.1	13.0	2.10
3--LP shell		188,000	419		1.623E+09	60.0	77.3	17.3	91.3	14.0	1.50
3--HP shell		188,000	419		1.354E+09	77.3	91.7	14.4	105.7	14.0	2.30

Table B-149
Scattergood Capacity Factors (Plant Only)

Unit	2001	2002	2003	2004	2005	2006	Average
all	24.8%	16.5%	31.7%	24.8%	13.6%	21.3%	22.1%

Table B-150
Scattergood Site Meteorological Data

Temperature	Max.	Average	Min.
Scattergood inlet temp., °F	68	63	57
Atmos. wet bulb, °F	70	57	30
Atmos. dry bulb, °F	90	65	35

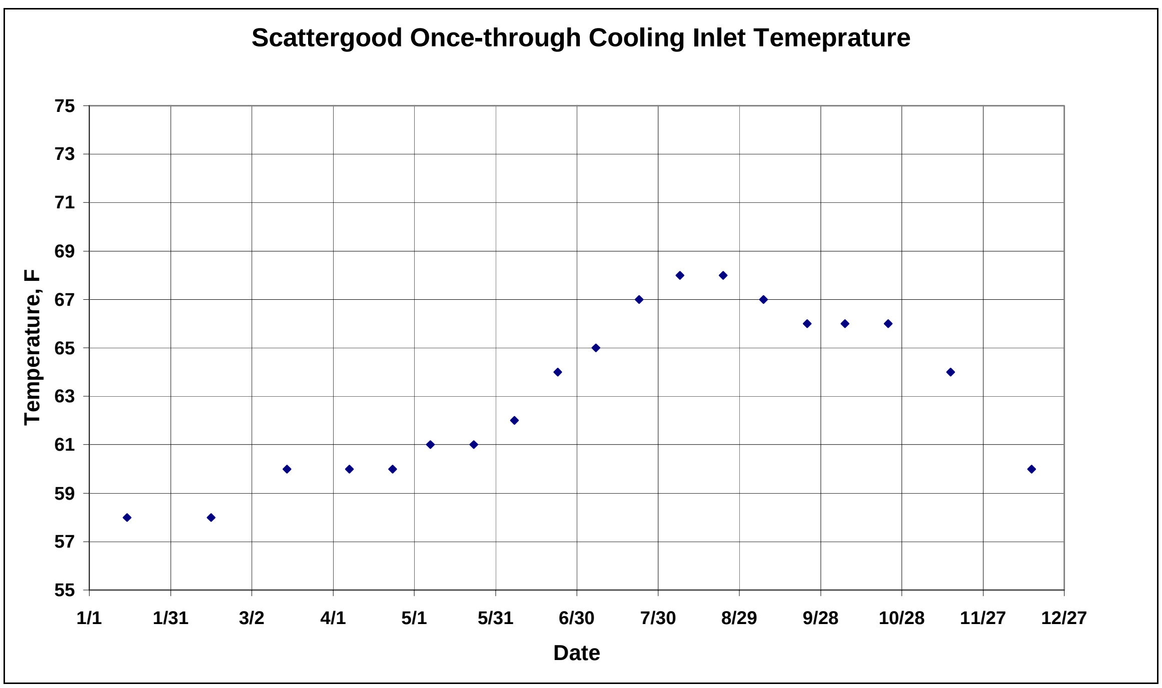


Figure B-116
Scattergood Inlet Temperatures

Plant Operating Data

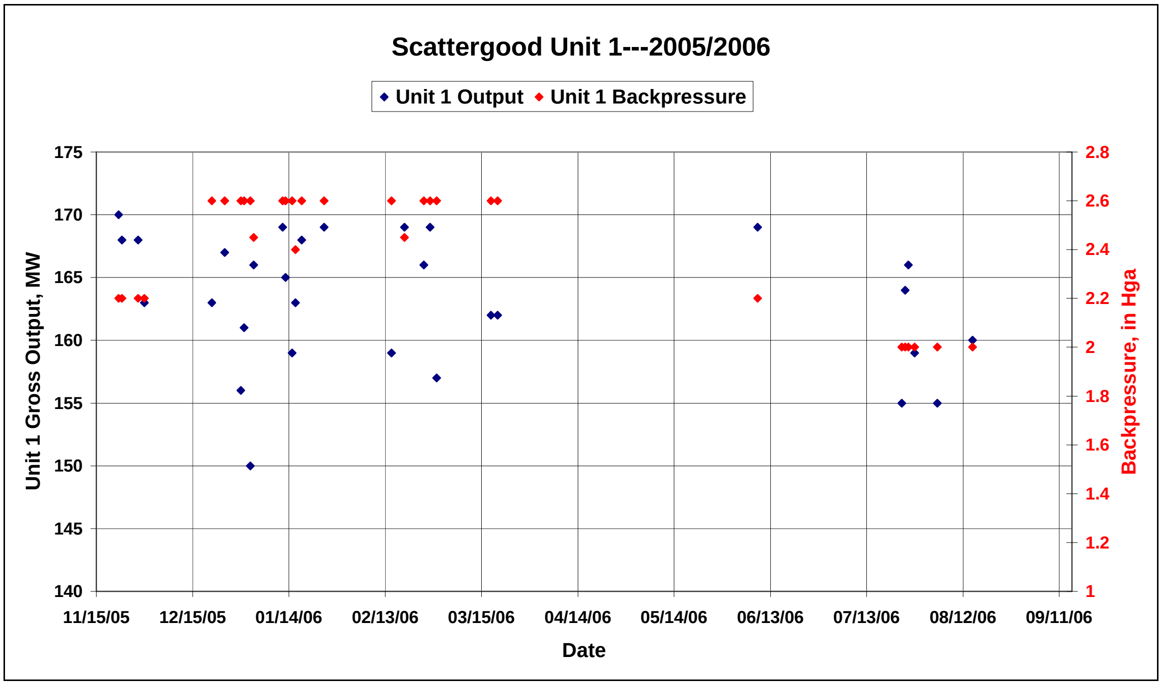


Figure B-117
Unit 1 Output and Backpressure

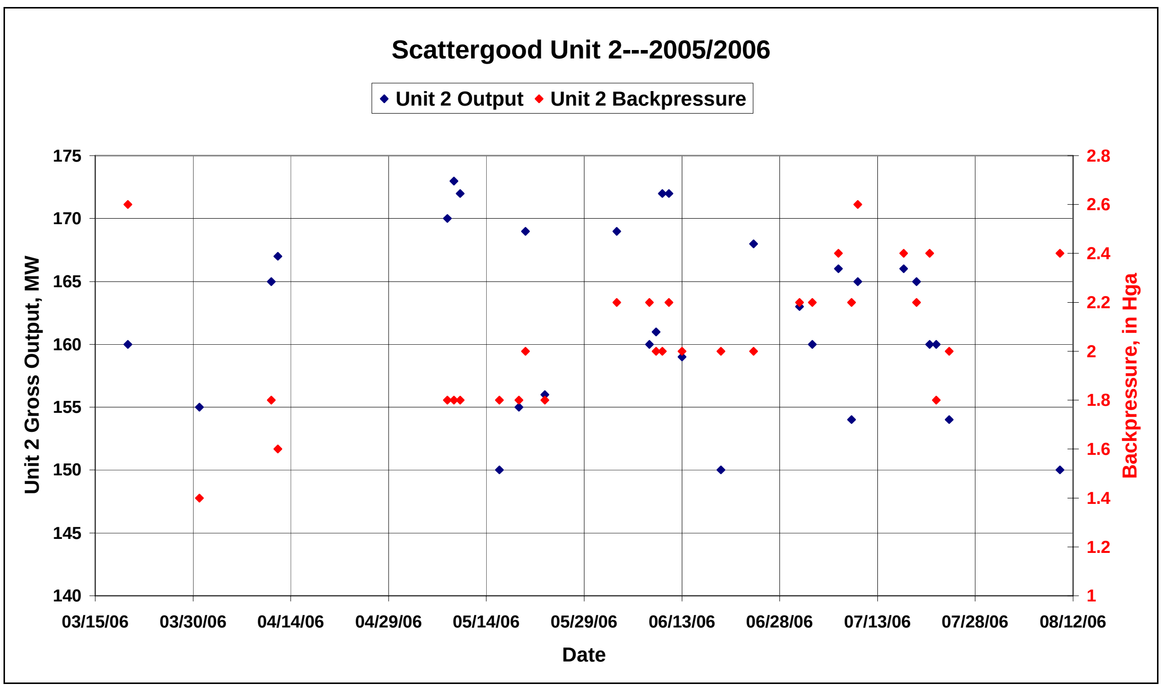


Figure B-118
Unit 2 Output and Backpressure

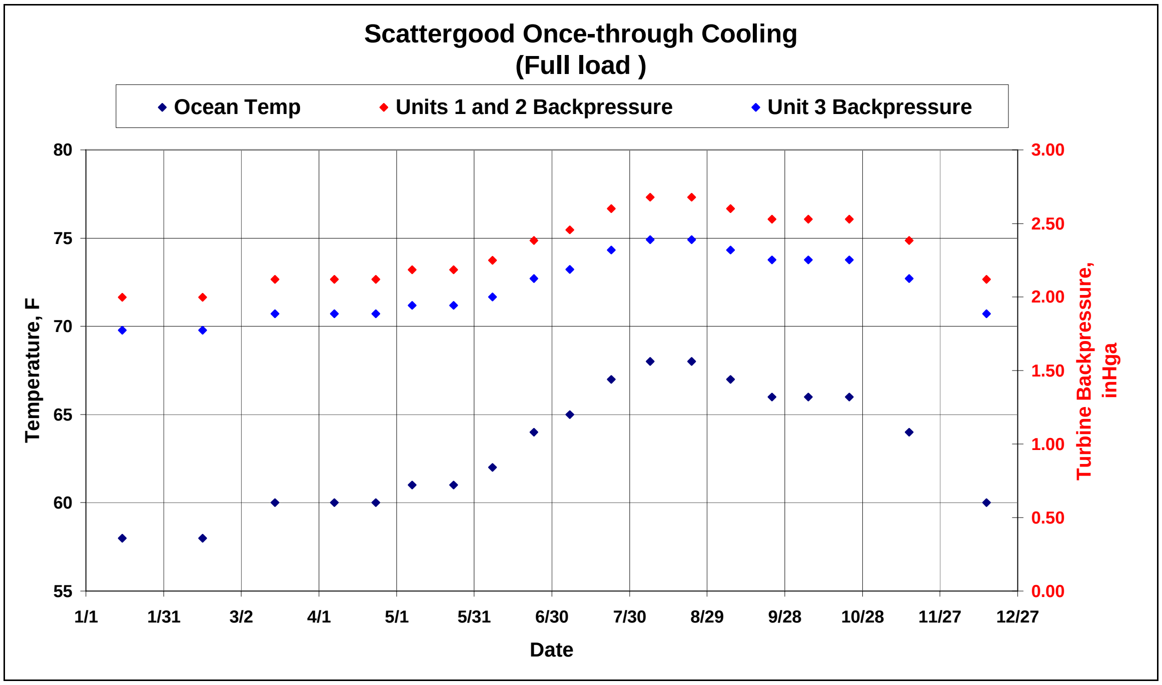


Figure B-119
Backpressure Estimated from Plant Data and Ocean Temperature

Similar plots could be generated for Unit 3, but data were not available to construct them. Units 1 and 2 will be used as representative examples for the plant. By comparison with the plots of Unit 1 and 2 output and backpressure above, the agreement is satisfactory. No plant data are available for Unit 3 operating conditions.

Cooling Tower Assumptions/Design

Wet cooling system design specifications for all units

- Tower type: mechanical draft, counterflow, FRP construction
- Make-up water source: Sea water; 35,000 ppm salinity
- Operating cycles of concentration: n = 1.5

Table B-151
Cooling Tower Water Balance Specifications

Unit	Evaporation gpm	Make-up gpm	Blowdown gpm
1	1,800	5,400	3,600
2	1,800	5,400	3,600
3	4,400	13,200	8,800

Tower design conditions are for all circulating water flows and condenser specifications unchanged, an assumed tower approach of 10°F and a peak wet bulb temperature of 70°F.

Table B-152
Cooling Tower Design Conditions for Full Load on Hot Day

Unit	Ambient Wet Bulb	Range	Approach	TTD	Tcond	Backpressure
	F	F	F	F	F	in Hga
1	70	29.2	10	13	122.2	~ 3.7
2	70	29.2	10	13	122.2	~ 3.7
3	70	30.1	10	14	124.1	~ 3.7

Therefore, on the hottest day at full load, all units would operate at a backpressure of approximately 3.7 in Hga. Over the course of the year when the ambient wet bulb temperature would be lower, The backpressure would vary as indicated in the following figure. A comparison is given to the backpressure estimated with once-through cooling and indicates that the backpressure would normally be elevated by 0.5 to 1. in Hga.

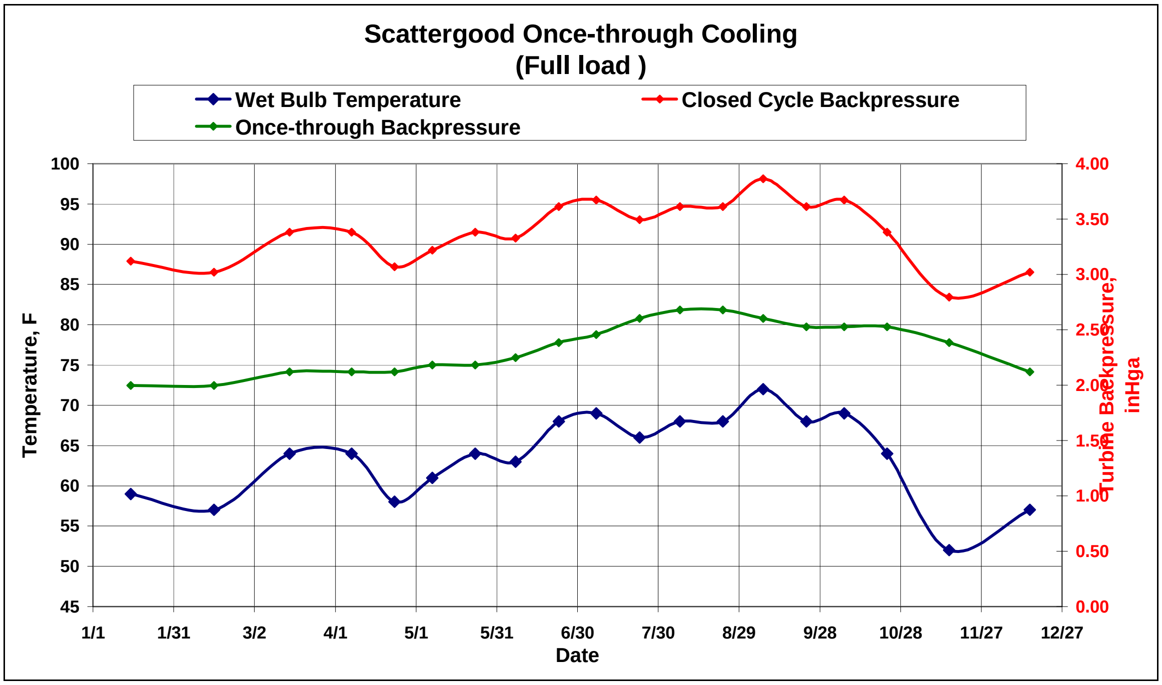


Figure B-120
Scattergood Backpressure Comparisons

Closed-Cycle Wet System Retrofit Costs

Table B-153
S&W Cost Estimates

S&W Costs---escalated to 2007; x 1.07 for seawater					
Unit	Labor	Material	Equipment	Indirect	Total
1	$5,483,000	$3,193,000	$5,427,000	$8,180,000	$22,282,000
2	$5,483,000	$3,193,000	$5,427,000	$8,180,000	$22,282,000
3	$13,223,000	$7,704,000	$13,102,000	$19,736,000	$53,765,000
Plant Total	$24,189,000	$14,090,000	$23,956,000	$36,096,000	$98,329,000

Table B-154
Maulbetsch Consulting Survey Estimates

Maulbetsch Consulting Survey; escalated to 2007 $; x 1.07 for salinity			
Unit	**Easy**	**Average**	**Difficult**
1	**$12,885,000**	**$21,476,000**	**$33,190,000**
2	**$12,885,000**	**$21,476,000**	**$33,190,000**
3	**$31,103,000**	**$51,838,000**	**$80,113,000**
Plant Total	**$56,873,000**	**$94,790,000**	**$146,493,000**

Dry Cooling

Similar cost estimates can be made for a dry cooling retrofit. The basic assumption is that for plants with low capacity factors, they must be available to produce close to full load on the hottest days of the year when the system load is at its peak. Therefore, using Unit 3 as an example

- Direct dry cooling: forced, mechanical-draft air-cooled condenser
- Steam flow: ~ 2,980,000 lb/hr (Unit 3 full load)
- Design dry bulb: 90°F (mid-way between 0.4% dry bulb and median of extreme highs)
- Design turbine exhaust pressure: 4.5 in Hga (based on assumption that turbines of this age and design trip at 5 in Hga and that the plant would not wish to reduce output on the hottest days)
- Corresponding condensing temperature: 130°F

Therefore, ACC design ITD ($T_{condensing}$ - $T_{design\ ambient}$) = 130°F – 90°F = **40°F**

Dry Cooling Retrofit Costs

AC costs can be roughly estimated from EPRI Report No. 1005358; "Comparison of Alternate Cooling Technologies for U.S. Power Plants", August, 2004.

Vendor information for a design of:

Steam flow: 2,980,000 lb/hr (using Unit 3 as an example)
ITD: 40°F
Price: 2002 $

Table B-155
Dry Cooling Retrofit Cost Estimates

Source/Basis	Equipment	Erection	Electrical	Duct Work	Indirect	Total
Vendor 1	$45,152,000	$19,316,000	$2,258,000	$677,000	$38,700,000	$106,103,000
Vendor 2	$37,376,000	$18,313,000	$2,258,000	$677,000	$33,610,000	$92,234,000
Average	$41,264,000	$18,814,500	$2,258,000	$677,000	$36,155,000	$99,168,500
Scaled to 2007 $	$51,131,000	$23,314,000	$2,798,000	$839,000	$44,801,000	$122,883,000
Including indirects	$80,788,000	$36,836,000	$4,421,000	$1,325,000	$70,785,000	$194,155,000

An ACC for this steam load at these conditions would have close to 90 cells possibly grouped in 15 rows of 6 cells each. A 90 cell ACC would occupy a rectangle of approximately 750 x 300 feet and the top of the steam duct would be over 125' high. A line of about the length of this ACC is shown on the aerial photo below. The location is about the only one on the property that looks adequate. However, that location puts the

ACC too far from the turbine exhaust to be viable. It appears that the installation of an ACC on this site can be shown to be virtually impossible on physical grounds and a more precise determination of the cost figures is not relevant.

Effect on Plant Performance

A retrofitted cooling system of either the wet or dry type would have a deleterious effect on the plant net heat rate. This arises from two effects:

1. Considering only the wet system, the power requirements will be higher than the current pumping power requirements for the once-through system. This power is used for the additional circulating pumps and for the cooling tower fans and represents power that must be generated but cannot be sold.
2. The plant will operate at a higher backpressure and therefore a higher heat rate with closed cycle cooling. This effect will be much more pronounced for a dry system than for a wet system.

The additional power requirements are estimated as follows:

Pumping power: The circulating water flow rate must be pumped through an additional head rise. This will be estimated at 40 feet to account for the lift out of the sump, the rise to the hot water distribution deck on the top of the tower and the head loss through the circulating water lines. A combined pump/motor efficiency of 75% is assumed. Each of these factors would be refined in a detailed analysis, but these are considered adequate to give a reasonable estimate of the effect of additional operating power on the plant. For the three units at Scattergood:

Table B-156
Scattergood Units: Retrofit Additional Pumping Power

Unit	Flow	Head	Eff	Power	Motor
	gpm	ft		kW	MW
1	78,000	40	0.75	587.5	0.78
2	78,000	40	0.75	587.5	0.78
3	188,000	40	0.75	1416.1	1.89

Fan power: Similarly cooling tower fan power can be roughly estimated. It is assumed for retrofits on older, lower capacity factor units, the tower would be sized to "low first cost" design since the number of operating hours is low and power penalties are less severe. This is consistent with the assumptions made in the retrofit capital cost estimates. The number of cells will be estimated as one cell per 10,000 gpm of circulating water flow, the fan horsepower at 200 HP and a motor efficiency of 90%. For the Scattergood units this results in:

Table B-157
Haynes Units: Retrofit Fan Power

Unit	Flow	Cells	Eff	Power	Motor
	gpm	n		hp	kW
1	78,000	8	0.9	1,560	1,293
2	78,000	8	0.9	1,560	1,293
3	188,000	19	0.9	3,760	3,117

This represents a combined, full-load operating power requirement of approximately 9.. MW or approximately 1.1% of the plant power rating of 838 MW. The actual annual cost will obviously depend on the capacity factor, the number of hours on-line, and whether some fans are turned off when operating at part load. Also, the cooling system was sized for full load at acceptable backpressures at so-called “1%” ambient conditions, it would be well oversized for nearly the entire year. Therefore, the effect of requiring additional operating power for the pumps and fans coupled with operation at higher heat rate would be an increase in the fuel burned rather than a reduction in plant output.

Heat rate penalty: As seen in the earlier plot of comparative backpressure, the condensing pressure with closed-cycle wet cooling will run typically 0.5 to 1.0 in Hga higher than it would with once-through ocean cooling and increases to about 2.5 in Hga on the hottest days. The effect is less at part load. No information is available on the effect of this elevated backpressure on heat rate. Information from other studies suggests that a reasonable estimate might be in the range of a 2. to 3. % increase in heat rate when going from 2.5 to 3.7 in Hga.

Capacity Limits

The increased back pressure will likely results in an output restriction at the hottest day. The magnitude of the shortfall will depend on the operating philosophy. If the firing rate is held constant, a 2.5 % heat rate penalty would correspond to roughly a 2.5 % reduction in output. Depending on the capability of the boiler and turbine this might be compensated for by overfiring the heat rate and fuel costs would increase even further.

If, however, it were to be decided that operation at a backpressure of over 3.5 in Hga constituted an unacceptable maintenance risk to the turbine, then the firing rate would need to be reduced to hold whatever backpressure was consider acceptable. Information to estimate what the shortfall would be in that case is not available but presumably could be estimated by plant staff based on the information given above.

Maintenance Costs

Commonly used factors for maintenance (labor, materials, chemicals, etc.) for wet cooling systems range from 2. to 3. % of the system capital costs.

For wet systems, the important costs are for water treatment, biofouling control and keeping the basin clean. Using salt water and having salt drift around the plant would require rust control, extra painting, etc. Using the high end of typical factors, assume 3. to 3.5% of the capital cost of the tower. It is unclear how LADWP would allocate these costs between operation and maintenance, but an estimate of 3% of the “average” capital costs for all units of $95 million could amount to over $2.5 million per year.

Additional Cost Considerations

Although the S&W costs are pretty close to the Maulbetsch Consulting survey’s “Average” difficulty estimate, neither of those estimates can account for any site-specific difficulties which might be encountered at the Scattergood site. Those items that could cause a retrofit at this site to be in a different, either “High” or “Easy” category include:

Location of Cooling Towers

The aerial photo below shows the only feasible locations for cooling towers. A discussion of these possible sites with plant staff resulted in the following observations.

1. The site north of the plant is the location of current entrance to the plant at the west and the reserved location for a re-powering project at the east part. It is not considered feasible to use this area for a cooling tower.

2. The site south of the plant is the entrance for deliveries of certain chemicals and the only location for oversize loads to enter the plant. This could be relocated, but significant re-grading of the area would be required and may not be practical. It may be possible but would be difficult, inconvenient and costly. The site in back (east) of the plant is the present location of existing small cooling towers,
an unused tank and three ammonia tanks. These are visible in the plant site photo at the beginning of this write-up. Operational difficulties would be involved in maintaining the auxiliary cooling capability until the new towers could be built and hooked up. An existing ammonia line would need to be relocated or some means would need to be developed to maintain the operation of the line during the construction period. Routing of new circulating lines around the plant (south of Unit 3 and North of Units 1 and 2) to hook in to the existing intake bay and discharge bay would again appear to be possible but of above average difficulty and cost.

Figure B-121
Possible Tower Locations

Additional considerations pertinent to all locations included:

i. Unstable soil conditions requiring significant foundation work such as deep pilings to stabilize the towers.

ii. Saturated soil conditions requiring dewatering for trenching and foundation digging.

iii. Soil and groundwater contamination from jet fuel which makes disposal of removed soil or pumped groundwater a costly requirement.

iv. Underground infrastructure which would make the installation of underground circulating water lines difficult and costly.

v. Possible objections to visible plumes and drift by both neighboring residential area and by nearby LAX.

Plume Abatement

Based on the view in the aerial photo of the neighboring area, it appears that a plume which would be visible both from nearby residential neighborhoods and from the beach could be a serious issue at this site primarily from an aesthetic viewpoint. It is also noteworthy that the runways at LAX are within 1 ½ miles of the site. While it is most improbable that a plume from a mechanical draft tower would impair visibility at that distance, the consequences would be viewed as very severe, and it might well be an important issue. It is reasonable to assume that a plume abatement tower would be required at this site.

Plume abatement towers have an air-cooled section on top of the wet tower. The hot water is pumped to the top of the tower, passes down through the dry section and then discharged onto the hot water distribution deck of the wet section. The air passing across the finned tubes of the dry section mixes with the wet plume coming off the wet section and keeps it from becoming saturated and condensing in the cold atmosphere. The need for a plume abatement tower would increase both the capital cost of the tower itself by a factor of perhaps 2. to 2.5 and the additional pumping power by an additional 30 to 50% due to the greater height to which the hot water must be pumped.

Aesthetics

In addition to any issues with a visual plume, the simple appearance of a cooling tower is sometimes considered an aesthetic affront. In this instance, even though the towers would be visible to neighbors, considering the number and size bulk of the plant buildings already present, it does not appear that this should present a major problem. However, the proximity of the beach may alter that perception.

Noise Control

Noise from wet cooling towers comes both from the fans and from the water cascading through the fill. Fan noise can be diminished by fan design or the reduction in air velocity which sometime requires the use of bigger, or more, cells. The water noise is more difficult to reduce and usually requires the construction of sound barriers around the cooling tower. As in the case of the plume abatement question, the aerial photo of the plant and the neighboring area makes it appear that cooling tower noise should not be a serious constraint. In case that it is, the capital cost of the tower itself cost might increase from 20 to 40%.

Alternate Sources of Make-Up Water

The use of seawater make-up can introduce intractable problems regarding drift and related maintenance considerations. (See later discussion of drift and PM10.) An alternative can be to purchase reclaimed water from nearby municipal water treatment facilities.

In this instance, the proximity of Hyperion with large quantities of reclaimable municipal waste water may make this alternative feasible. However, cooling towers will require tertiary treated water which is not available directly from Hyperion. Therefore the water would need either to be obtained from the West Basin Municipal water district facility at a much greater distance from the plant or treated on site at additional cost. Other issues include the presence of ammonia in the water and hence compatibility with existing condenser materials.

The possibility of using this water was studied in 1995 by two firms. Both identified the presence of ammonia in the water as a problem due to incompatibility with the use of

Admiralty brass in the existing condensers. Ammonia stripping was feasible at a cost. The elimination of maintenance and drift problems that would be incurred if seawater make-up were used would appear to make this an attractive alternative if the water is in fact available.

Shutdown Period

There is often concern over the period of post plant availability during the retrofit construction period. In this instance, it appears that the major part of the construction could be done while the plant is on-line, with shutdown required only for the final tie-in of the circulating water lines to the existing water circuit. There is no information available to estimate how long this might be. However, the operating profiles shown earlier for Units 1 and 2 indicate periods of little or no operation. Therefore, it appears that the tie-in could be accomplished with no serious downtime, although one of the two units would need to be available at all times requiring that the tie-in of the units be done sequentially. The issue of maintaining auxiliary cooling during the construction of the tower is a consideration but could presumably be dealt with although at extra cost, by relocating the aux coolers and the ammonia line discussed in an earlier section prior to the start of construction

Other Environmental Issues

Retrofit to a closed-cycle cooling system introduces some environmental issues which a once-through cooling system does not. These are increased air emissions from the stack and drift from the cooling tower.

Stack Emissions

In an earlier section it was noted that a closed-cycle retrofit increase the unit net output because of heat rate penalties and the use of increased operating power. In this instance these together were estimated at from 2 to 3 %. Therefore, the delivery of the same amount of electric power to the grid will require the burning of additional fuel at some location to make up that lost at Scattergood. Based on the unit heat rate information provided, this does not appear to be major effect in this case. Furthermore, in the discussion of this issue in Chapter 7, it was pointed out that the effect of making up this shortfall was highly variable depending on how and where the replacement per was generated. Therefore, no attempt is made to asses the effect in quantitative terms beyond pointing out that reliable estimates of the shortfall to be expected from full load operation can be made.

Drift

It is assumed that any cooling tower would be equipped with state-of-the-art drift eliminators rated at about 0.0005% of circulating water flow. The following table estimates the amount of drift to be expected from such designs. In addition, as discussed earlier, Federal EPA and State regulations characterize all solids carried off in cooling tower drift as PM10. The cost of offsetting these amount, should it be necessary will vary considerably from site to site as will the severity of the regulatory constraints.

Table B-158
Scattergood Drift Estimates

Unit	Flow gpm	Drift[1] gpm	Drift lb/hr	PM10 lb/hr	PM10 tons/year[2]	Cap. Factor %	PM10 tons/year[3]
1	**78,000**	0.39	195	9.75	42.7	**24.7**	**10.5**
2	**78,000**	0.39	195	9.75	42.7	**24.7**	**10.5**
3	**188,000**	0.94	470	23.49	102.9	**24.7**	**25.4**

1. At drift eliminator efficiency of 0.0005%
2. Assumes full load all year
3. At 2006 capacity factor

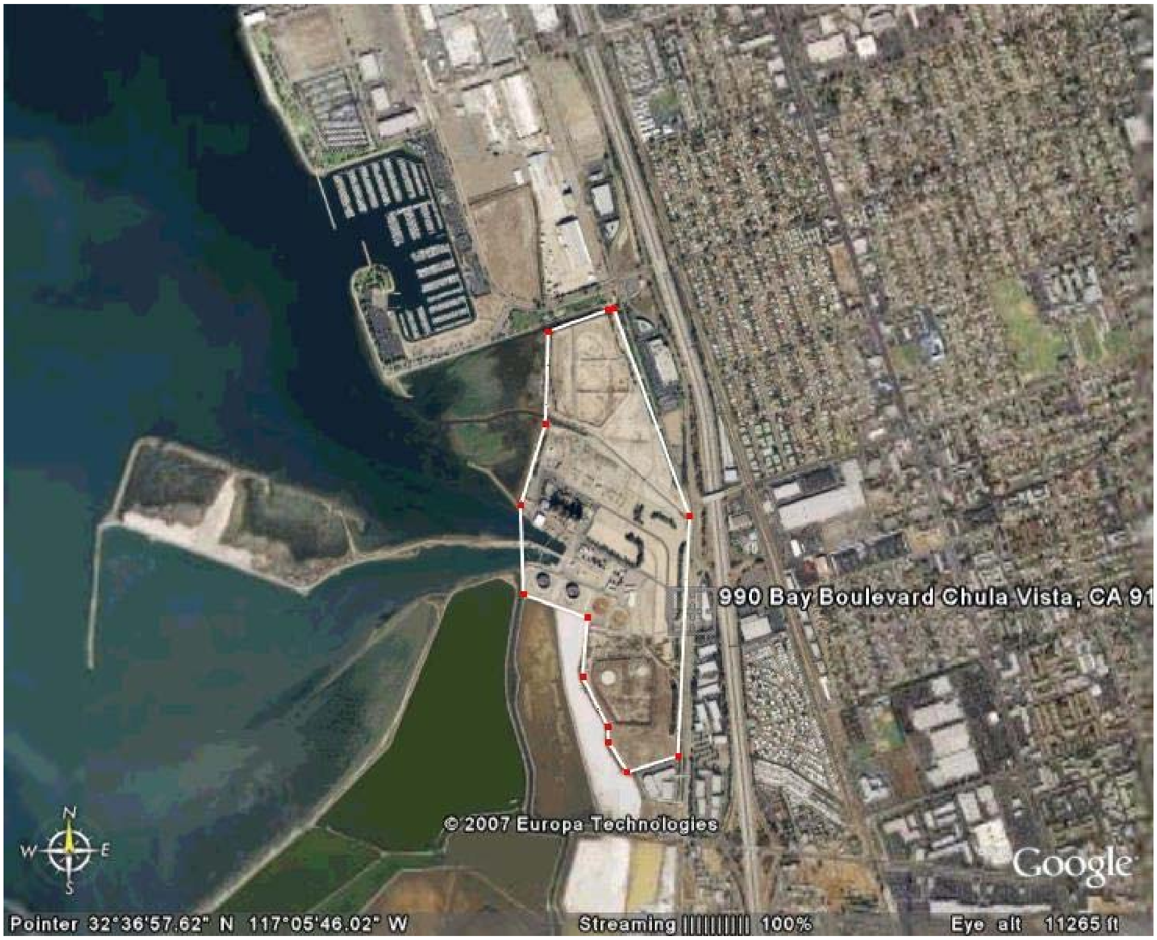
General Conclusion

On balance, it is concluded that the nature of the likely problems and additional costs to be encountered at Scattergood would put the retrofit at this site in a “more difficult than average” category. Based on the results from the Maulbetsch Consulting survey presented above, this would probably put the project cost in the range of $100 to $120 million.

B.17 South Bay, LLC South Bay Power Plant (Operated by Dynegy)

Location

990 Bay Boulevard
Chula Vista, CA 91911-1651
32° 36’ 39.15” N; 117° 05’ 40.21” W
Contact: Barb Irwin, 217/519-4035



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South Bay Generating Station: Boundary and Neighborhood

Figure B-123
South Bay Site View

Plant/Site Information

Units 1 and 2: 136 MW
Unit 3: 210 MW
Unit 4: 214 MW

Operating data for Unit 3 at full load was provided by the plant.

Heat duty:	4,470 Btu/kWh
Cooling water flow:	516 gpm/MW
Range:	17°F
TTD:	11.4°F

In the absence of other information, these values were assumed for all units.

Table B-159
South Bay Cooling System Operating Conditions

Unit	MW	Cooling Water flow		Steam flow	Heat duty	Tin	Tex	Range	Tcond	TTD	Backpressure
		gpm	cfs	lb/hr	Btu/hr	F	F	F	F	F	in Hga
1	**136**	70,176	156	6.40E+05	6.08E+08	63.0	80.0	17.0	91.4	11.4	1.5
2	**136**	70,176	156	6.40E+05	6.08E+08	63.0	80.0	17.0	91.4	11.4	1.5
3	**210**	108,360	241	9.88E+05	9.39E+08	63.0	80.0	17.0	91.4	11.4	1.5
4	**214**	110,424	246	1.01E+06	9.57E+08	63.0	80.0	17.0	91.4	11.4	1.5

Table B-160
South Bay Capacity Factors

Unit-Level Capacity Factors							
Unit	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**Average**
1	51.5%	35.5%	34.1%	43.6%	45.9%	32.5%	40.5%
2	51.2%	37.3%	39.2%	51.3%	35.8%	29.7%	40.8%
3	31.0%	16.2%	22.2%	29.8%	23.6%	7.0%	21.6%
4	9.6%	4.1%	2.5%	12.5%	6.7%	4.8%	6.7%

Table B-161
South Bay Meteorological Data

Temperature	Max.	Average	Min.
South Bay inlet temp., °F	68	63	57
Atmos. wet bulb, °F	71	56	27
Atmos. dry bulb, °F	92	66	29

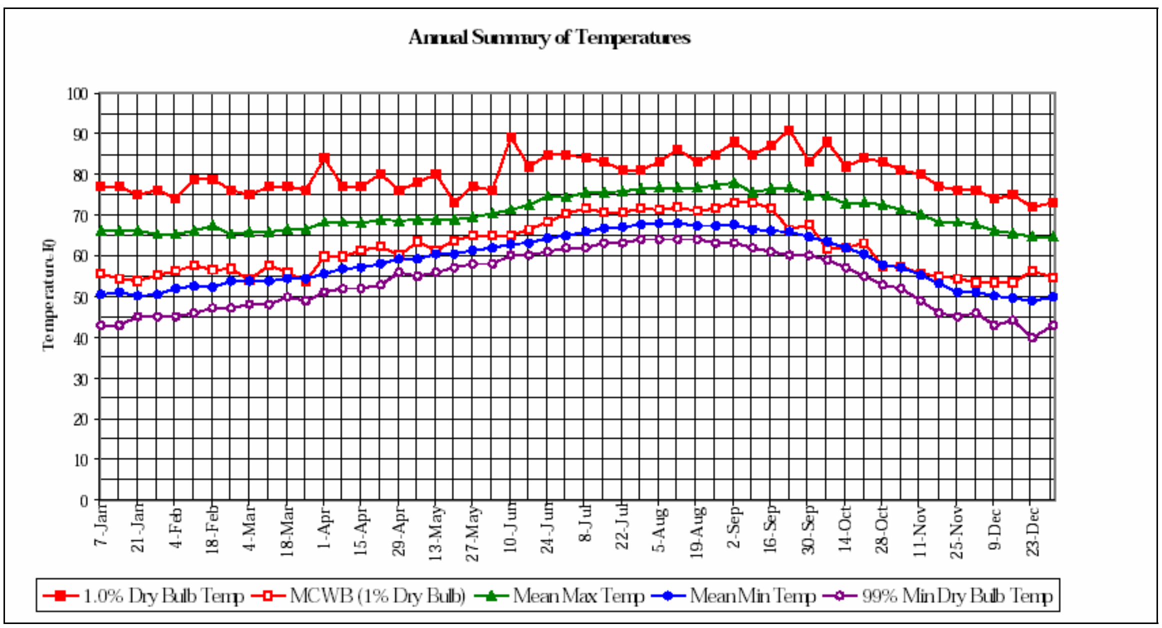

Figure B-124
South Bay Meteorological Data––Based on San Diego information

Plant Operating Data

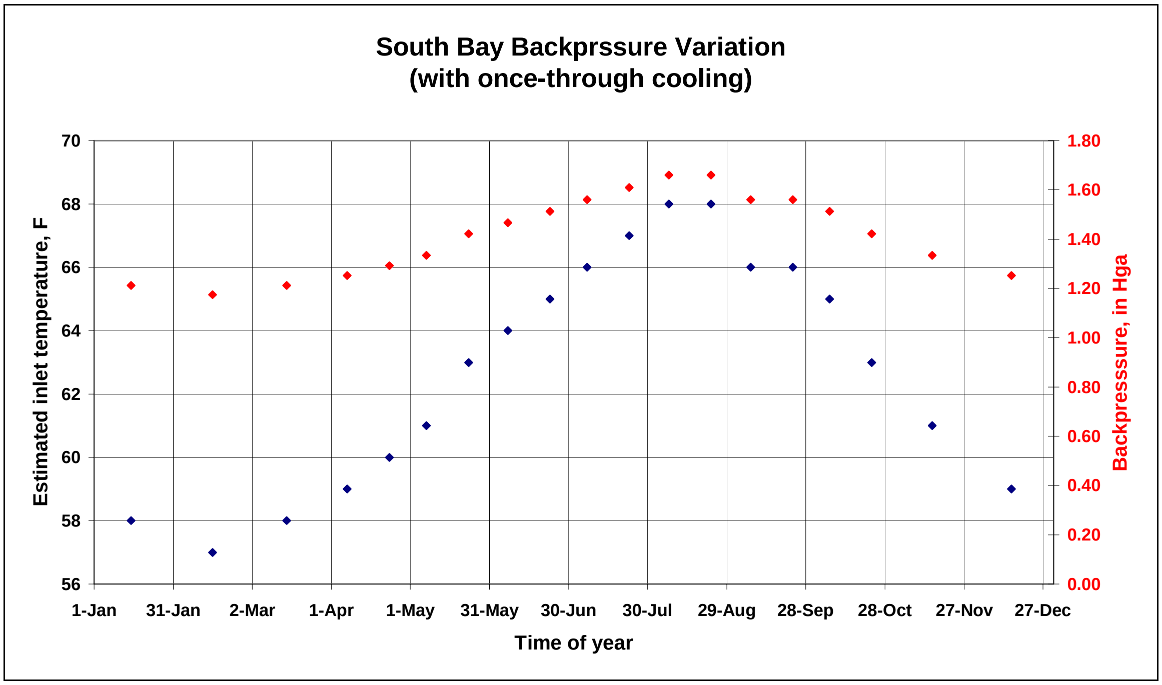

Figure B-125
Seasonal Inlet Temperature and Backpressure Variation (Once-Through Cooling)

Cooling Tower Assumptions/Design

Wet cooling system design specifications

- Tower type: mechanical draft, counterflow, FRP construction
- Make-up water source: Sea water; 35,000 ppm salinity
- Operating cycles of concentration: n = 1.5
- Evaporation rate: Units 1 and 2--- ~ 1,400 gpm each
  Units 3 and 4--- ~ 2,100 gpm each
- Make-up rate (@ n = 1.5): Units 1 and 2--- ~ 4,200 gpm each
  Units 3 and 4 --- ~ 6,300 gpm each
- Blowdown (@ n = 1.5): Units 1 and 2 --- ~ 2,800 gpm each
  Units 3 and 4 --- ~ 4,200 gpm each

Tower design values are for the circulating water flow rates and the condenser specifications unchanged, an assumed tower approach of 10°F and a peak wet bulb temperature of 71°F.

This results in

- Ambient wet bulb: 71°F
  Range: 17.°F
  Approach: 10°F
- TTD: 11.4°F

yielding a condensing temperature of

$$T_{cond} = 71 + 10 + 17. + 11.4. = 109.4°F$$

and a backpressure of 2.5 in Hga at full load on the hottest day.

Therefore, on the hottest day at full load, all units would operate at a backpressure of approximately 2.5 in Hga. Over the course of the year when the ambient wet bulb temperature would be lower, the backpressure would vary as indicated in the following figure. A comparison is given to the backpressure estimated with once-through cooling and indicates that the backpressure would normally be elevated by 0.5 to 1.0 in Hga.

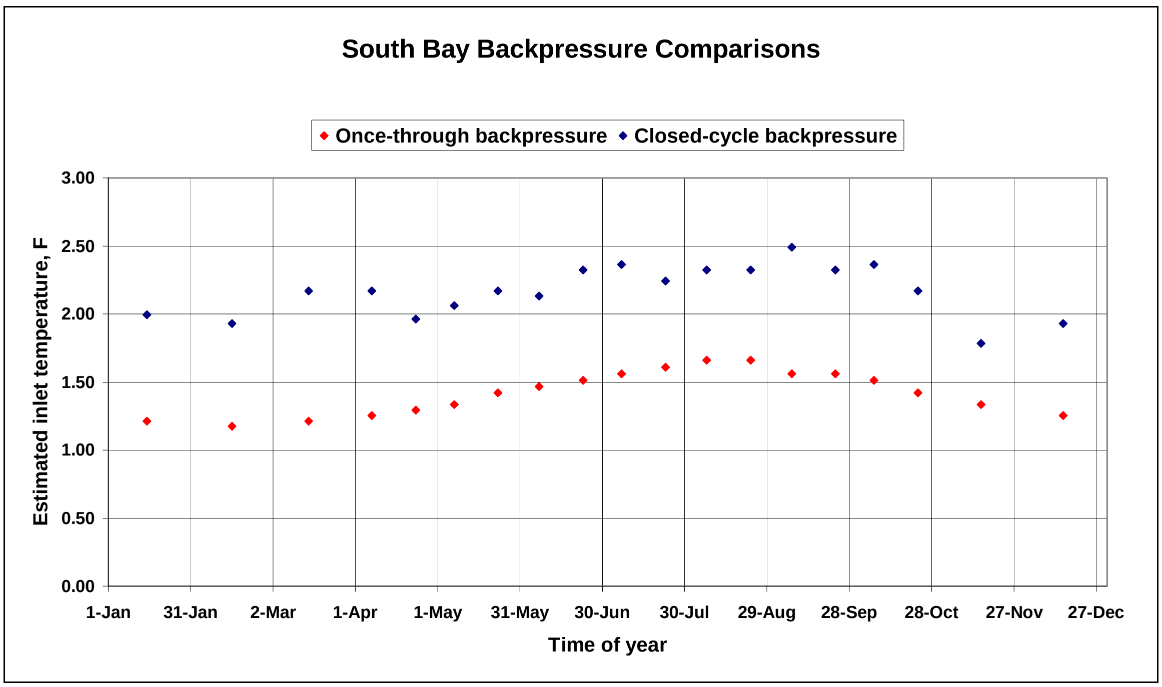

Figure B-126
Backpressure Comparisons

Wet Retrofit Costs

Table B-162
S&W Cost Estimates

S&W Costs---escalated to 2007; x 1.07 for seawater					
Unit	**Labor**	**Material**	**Equipment**	**Indirect**	**Total**
1	**$5,036,000**	**$2,935,000**	**$4,997,000**	**$7,522,000**	**$20,491,000**
2	**$5,036,000**	**$2,935,000**	**$4,997,000**	**$7,522,000**	**$20,491,000**
3	**$8,187,000**	**$4,768,000**	**$8,119,000**	**$12,223,000**	**$33,297,000**
4	**$8,187,000**	**$4,768,000**	**$8,119,000**	**$12,223,000**	**$33,297,000**
Plant Total	**$26,446,000**	**$15,406,000**	**$26,232,000**	**$39,490,000**	**$107,576,000**

Table B-163
Maulbetsch Consulting Survey Estimates

JSM Survey; escalated to 2007 $; x 1.07 for salinity			
Unit	**Easy**	**Average**	**Difficult**
1	**$11,220,000**	**$18,700,000**	**$28,900,000**
2	**$11,220,000**	**$18,700,000**	**$28,900,000**
3	**$17,325,000**	**$28,875,000**	**$44,625,000**
4	**$17,655,000**	**$29,425,000**	**$45,475,000**
Plant Total	**$57,420,000**	**$95,700,000**	**$147,900,000**

Dry Cooling

Similar cost estimates can be made for a dry cooling retrofit. The basic assumption is that for plants with low capacity factors, they must be available to produce close to full load on the hottest days of the year when the system load is at its peak.

- Direct dry cooling: forced, mechanical-draft air-cooled condenser
- Steam flow: Units 1 and 2: ~ 720,000 lb/hr (full load)

  Units 3 and 4: ~ 1,200,000 lb/hr (full load)
- Design dry bulb: 95°F (mid-way between 0.4% dry bulb and median of extreme highs)
- Design turbine exhaust pressure: 4.5 in Hga (based on assumption that turbines of this age and design trip at 5 in Hga and that the plant would not wish to reduce output on the hottest days)
- Corresponding condensing temperature: 130°F

Therefore, ACC design ITD ($T_{condensing}$ - $T_{design\ ambient}$) = 130ºF – 95ºF = 35°F

Dry Cooling Retrofit Costs

AC costs can be roughly estimated from EPRI Report No. 1005358; "Comparison of Alternate Cooling Technologies for U.S. Power Plants", August, 2004.

Vendor information for a design of:

Steam flow: Units 1 and 2: 720,000 lb/hr (scaled from 1,080,000 lb/hr)
Units 3 and 4: 1,120,000 lb/hr (scaled from 1,080,000 lb/hr)
ITD: 35°F

Price: 2007 $

It should be noted at the outset that this would be a very large ACC with between 80 and 100 cells. This would be the largest ACC on a single unit anywhere in the world to my knowledge. Cost extrapolations to this size range are uncertain without obtaining confirming estimates from vendors which is beyond the scope of this effort. However, the cost estimate *for each unit* based on straight-forward linear extrapolation from more normal sizes is given below.

Table B-164
Dry Cooling Retrofit Cost Estimates—Units 1 and 2

Source/Basis	Equipment	Erection	Electrical	Duct Work	Indirect	Total	Cells
Vendor 1	$12,521,000	$5,358,000	$820,000	$82,000	$10,846,000	$29,627,000	30
Vendor 2	$13,122,000	$5,632,000	$656,000	$82,000	$11,258,000	$30,750,000	20
Vendor 3	$10,717,000	$5,249,000	$656,000	$82,000	$9,641,000	$26,344,000	20
Average	$12,120,000	$5,413,000	$711,000	$82,000	$10,582,000	$28,907,000	25
Scaled to 2007 $	$16,219,000	$6,447,000	$951,000	$110,000	$13,698,000	$37,425,000	

Table B-165
Dry Cooling Retrofit Cost Estimates—Units 3 and 4

Source/Basis	Equipment	Erection	Electrical	Duct Work	Indirect	Total	Cells
Vendor 1	$19,625,000	$8,399,000	$1,286,000	$129,000	$16,999,000	$46,437,000	45
Vendor 2	$20,568,000	$8,827,000	$1,028,000	$129,000	$17,646,000	$48,198,000	35
Vendor 3	$16,797,000	$8,227,000	$1,028,000	$129,000	$15,111,000	$41,292,000	35
Average	$18,997,000	$8,484,000	$1,114,000	$129,000	$16,586,000	$45,309,000	40
Scaled to 2007 $	$25,422,000	$10,105,000	$1,491,000	$172,000	$21,470,000	$58,660,000	

This would result in the cost of the plant's retrofit cost to dry cooling of over $190,000,000 and consume approximately 20 MW of fan power.

Effect on Plant Performance

A retrofitted cooling system of either the wet or dry type would have a deleterious effect on the plant net heat rate. This arises from two effects:

1. Considering only the wet system, the power requirements will be higher than the current pumping power requirements for the once-through system. This power is used for the additional circulating pumps and for the cooling tower fans and represents power that must be generated but cannot be sold.
2. The plant will operate at a higher backpressure and therefore a higher heat rate with closed cycle cooling. This effect will be much more pronounced for a dry system than for a wet system.

The additional power requirements are estimated as follows:

Pumping power: The circulating water flow rate must be pumped through an additional head rise. This will be estimated at 40 feet to account for the lift out of the sump, the rise to the hot water distribution deck on the top of the tower and the head loss through the circulating water lines. A combined pump/motor efficiency of 75% is assumed. Each of these factors would be refined in a detailed analysis, but these are considered adequate to give a reasonable estimate of the effect of additional operating power on the plant. For the four units at South Bay:

Table B-166
South Bay Units: Retrofit Additional Pumping Power

Unit	Flow	Head	Eff	Power	Motor
	gpm	ft		kW	MW
1	68,000	40	0.75	512.2	0.68
2	68,000	40	0.75	512.2	0.68
3	105,000	40	0.75	790.9	1.05
4	107,000	40	0.75	806.0	1.07

Fan power: Similarly cooling tower fan power can be roughly estimated. It is assumed for retrofits on older, lower capacity factor units, the tower would be sized to "low first cost" design since the number of operating hours is low and power penalties are less severe. This is consistent with the assumptions made in the retrofit capital cost estimates. The number of cells will be estimated as one cell per 10,000 gpm of circulating water flow, the fan horsepower at 200 HP and a motor efficiency of 90%. For the South Bay units this results in:

Table B-167
South Bay Units: Retrofit Fan Power

Unit	Flow	Cells	Eff	Power	Motor
	gpm	n		hp	kW
5	72,000	7	0.9	1,400	1,160
6	72,000	7	0.9	1,400	1,160
7	234,000	23	0.9	4,600	3,813
8	234,000	23	0.9	4,600	3,813

This represents a combined, full-load operating power requirement of approximately 10. MW or slightly less than 1.5 % of the plant power rating of approximately 700 MW. The actual annual cost will obviously depend on the capacity factor, the number of hours on-line, and whether some fans are turned off when operating at part load. Also, the cooling system was sized for full load at acceptable backpressures at so-called "1%" ambient conditions, it would be well oversized for nearly the entire year. Therefore, the effect of requiring additional operating power for the pumps and fans coupled with operation at higher heat rate would be an increase in the fuel burned rather than a reduction in plant output.

Heat rate penalty: As seen in the earlier plot of comparative backpressure, the condensing pressure with closed-cycle wet cooling will run typically 0.5 to 1.0 in Hga higher than it would with once-through ocean cooling and increases to about 2.5 in Hga on the hottest days. The effect is less at part load. No information is available to estimate the heat rate penalty under these operating conditions.

Capacity Limits

The increased back pressure will likely result in an output restriction at the hottest day. The magnitude of the shortfall will depend on the operating philosophy. If the firing rate is held constant, a 1 to 2 % heat rate penalty (plausible estimate based on units of similar age and design) would correspond to roughly a 1 to 2 % reduction in output. This might be compensated for partially by overfiring the unit if possible, but the heat rate penalty and hence the fuel costs, would increase even further.

If, however, it were to be decided that operation at a backpressure of 2.5 in Hga constituted an unacceptable maintenance risk to the turbine, then the firing rate would need to be reduced to hold whatever backpressure was consider acceptable. Information to estimate what the shortfall would be in that case is not available but presumably could be estimated by plant staff based on the information given above.

Maintenance Costs

Commonly used factors for maintenance (labor, materials, chemicals, etc.) for wet cooling systems range from 2. to 3. % of the system capital costs.

For wet systems, the important costs are for water treatment, biofouling control and keeping the basin clean. Using salt water and having salt drift around the plant would require rust control, extra painting, etc. Using the high end of typical factors, assume 3. to 3.5% of the capital cost of the tower. It is unclear how these costs would be allocated between operation and maintenance, but an estimate of 3% of the "average" capital costs for all units of $10 million could amount to approximately $3,000,000 per year.

Additional Cost Considerations

Although the S&W costs are pretty close to the Maulbetsch Consulting survey's "Average" difficulty estimate, neither of those estimates can account for any site-specific difficulties which might be encountered at the South Bay site. Those items that could cause a retrofit at this site to be in a different, either "High" or "Easy" category include:

- Difficulty in locating the tower
- Unusual site preparation costs
- Significant interferences to the cost of installation of the circulating water lines
- The need for cooling tower plume abatement
- Stringent noise control
- The use of an alternate make-up water

Location of Tower/Unusual Site Preparation Costs/Interferences

Although no definite information on restrictions on the use of areas of the plant property are available, it appears from the aerial view of the plant boundaries and the neighboring areas, that adequate room for cooling towers exists, particularly to the east of the plant.

No information is available on site geology or soil characteristics. If, as is sometimes the case in near coastal areas, the ground is saturated and unstable, the installation of the tower basin and the circulating water lines may be difficult.

There is no information on underground infrastructure from which to estimate the likelihood of interferences to the installation of circulating water lines.

Plume Abatement

Based on the view in the aerial photo of the neighboring area, it appears that a visible plume may be a serious issue at this site primarily both from an aesthetic perspective to nearby residential areas and from a safety viewpoint to the nearby highway. There would be a need to consider a plume abatement tower at this site.

Plume abatement towers have an air-cooled section on top of the wet tower. The hot water is pumped to the top of the tower, passes down through the dry section and then discharged onto the hot water distribution deck of the wet section. The air passing across the finned tubes of the dry section mixes with the wet plume coming off the wet section and keeps it from becoming saturated and condensing in the cold atmosphere. The need for a plume abatement tower would increase both the capital cost of the tower itself by a factor of perhaps 2. to 2.5 and the additional pumping power by an additional 30 to 50% due to the greater height to which the hot water must be pumped.

Aesthetics

In addition to any issues with a visual plume, the simple appearance of a cooling tower is sometimes considered an aesthetic affront. In this instance, even though it appears that the towers would be visible from the highway and residential areas, considering the size and bulk of the plant buildings already present, this may not present a major problem.

Noise Control

Noise from wet cooling towers comes both from the fans and from the water cascading through the fill. Fan noise can be diminished by fan design or the reduction in air velocity which sometime requires the use of bigger, or more, cells. The water noise is more difficult to reduce and usually requires the construction of sound barriers around the cooling tower. As in the case of the plume abatement question, the aerial photo of the plant and the neighboring area makes it appear that cooling tower noise may be a serious constraint.

Alternate Sources of Make-Up Water

No information is available to identify the availability of alternate water sources. Therefore, the use of seawater make-up is assumed for this site.

Shutdown Period

There is often concern over the period of post plant availability during the retrofit construction period. In this instance, it appears that the major part of the construction could be done while the plant is on-line, with shutdown required only for the final tie-in of the circulating water lines to the existing water circuit. There is no information available to estimate how long this might be. However, recent capacity factors are quite low at least on Units 3 and 4, and it would appear that the tie-in could be accomplished with no significant downtime for those units. No information is available to render a judgment for Units 1 and 2.

Other Environmental Issues

Retrofit to a closed-cycle cooling system introduces some environmental issues which a once-through cooling system does not. These are increased air emissions from the stack and drift from the cooling tower.

Stack Emissions

In an earlier section it was noted that a closed-cycle retrofit increase the unit net output because of heat rate penalties and the use of increased operating power. Although no specific heat rate information is available for these units, a reasonable estimate based on units of similar age and design might be in the range of from 2 %. Therefore, the delivery of the same amount of electric power to the grid may require the burning of additional fuel at some location to make up that lost at South Bay. If the relatively low frequency of operation at South Bay implies that, when it does operate, it does so at full load then the lost power will have to be made up elsewhere. On the other hand, if operation is normally at partial load, the output might simply be increased at the site except on the very hottest days when the units might be backpressure limited. Therefore, no attempt is made to asses the effect in quantitative terms beyond pointing out that reliable estimates of the shortfall to be expected from full load operation can be made.

Drift

It is assumed that any cooling tower would be equipped with state-of-the-art drift eliminators rated at about 0.0005% of circulating water flow. The following table estimates the amount of drift to be expected from such designs. In addition, as discussed earlier, Federal EPA and State regulations characterize all solids carried off in cooling tower drift as PM10. The cost of offsetting this amount, should it be necessary will vary considerably from site to site as will the severity of the regulatory constraints.

Table B-168
South Bay Drift Estimates

Unit	Flow	Drift[1]	Drift	PM10	PM10	Cap. Factor	PM10
	gpm	gpm	lb/hr	lb/hr	tons/year[2]	%	tons/year[3]
1	**68,000**	0.34	170	8.50	37.2	**24.7**	**9.2**
2	**68,000**	0.34	170	8.50	37.2	**24.7**	**9.2**
3	**105,000**	0.53	262	13.12	57.5	**25.7**	**14.8**
4	**107,000**	0.54	267	13.37	58.6	**26.7**	**15.6**

1. At drift eliminator efficiency of 0.0005%
2. Assumes full load all year
3. At 2006 capacity factor

The aerial view of the surrounding area indicates that salt deposition might be a concern. Although experience at other sites with salt water towers equipped with modern, high efficiency drift eliminators has indicated no detectable off-site damage, the possibility should be analyzed in advance of retrofit.

General Conclusion

On balance, it is concluded that there are no obvious problems associated with a retrofit to closed-cycle wet cooling at this site which would differentiate South Bay from a retrofit of “average” difficulty although there may be factors unknown to this study.