California's Coastal Power Plants: Alternative Cooling System Analysis

— prepared by —

Tetra Tech, Inc.

Golden, CO

Tim Havey, Project Manager

— prepared for —

California Ocean Protection Council

Oakland, CA

Christine Blackburn, Ph.D., Project Manager

February 2008

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This report was funded by the California Ocean Protection Council and has benefitted greatly from the many contributions provided by individuals and organizations, including state agency staff, industry representatives, technology vendors and third-party experts. Their input and insight has been critical to the final analysis and is reflected throughout the document.

California Ocean Protection Council
Christine Blackburn, Project Manager
Drew Bohan, Executive Policy Officer
Jon Gurish, Staff Counsel

California Coastal Commission
Tom Luster

State Water Resources Control Board
Dominic Gregorio

California Energy Commission
Jim McKinney
Joe O'Hagan
John Kessler
Caryn Holmes
Matt Layton

Technical review of segments of this report provided by:

- John Maulbetsch, Ph.D., Maulbetsch Consulting
- Bill Powers, P.E., Powers Engineering
- Ron Rimelman, Tetra Tech, Inc.

Representatives of companies whose facilities comprise California's coastal power plants:

- AES Southland, LLC.
- Dynegy, Inc.
- El Segundo Power, LLC.
- Los Angeles Department of Water and Power
- Mirant Delta, LLC.
- Pacific Gas and Electric
- Reliant Energy, Inc.
- Southern California Edison

Technology vendors:

Particular appreciation is extended to Aaron Atherton of GEA Power Cooling, Inc. for providing numerous cooling tower budget estimates and technical specifications for individual facilities in this report.

Also noted for their contributions are:

- Enviroair (on behalf of Marley/SPX Cooling, Inc.)
- Price Brothers Company
- HiTech Piping, Ltd. (on behalf of Reinforced Plastic Systems, Inc.)
- Romatec (on behalf of Mosser Valves)
- Weir Pumps
- Holtec International, Inc.
- Groupe Laperrière & Verreault Inc.

Also recognized are the significant contributions from Hatch, Ltd., under subcontract to Tetra Tech, Inc., in developing cost and engineering estimates for each facility profile. The final report reflects a collaborative effort in these areas between Bernard Bruman, Hatch, Ltd. Project Manager, and the author.

CALIFORNIA'S COASTAL POWER PLANTS: ALTERNATIVE COOLING SYSTEM ANALYSIS

— FINAL REPORT —

— prepared for —

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ACRONYMS AND ABBREVIATIONS

ACC	Air-cooled condenser
AFB	Aquatic Filtration Barrier
AGS	Alamitos Generating Station
APCD	Air Pollution Control District
AQMD	Air Quality Management District
ASHRAE	American Society of Heating, Refrigerating and Air-conditioning Engineers
BAAQMD	Bay Area Air Quality Management District
BACT	Best Available Control Technology
BAT	Best Available Technology Economically Achievable
BCDC	Bay Conservation and Development Commission
BHP	Brake horsepower
BPJ	Best Professional Judgment
BTA	Best Technology Available
BTU	British Thermal Unit
CARB	California Air Board
CCA	California Coastal Act
CCC	California Coastal Commission
CCPP	Contra Costa Power Plant
CCR	California Code of Regulations
CCRWQCB	Central Coast Regional Water Quality Control Board
CDFG	California Department of Fish and Game
CDP	Coastal Development Permit
CEC	California Energy Commission
CEMS	Continuous Emission Monitoring System
CEQA	California Environmental Quality Act
CIMIS	California Irrigation Management Information System
CNEL	Community noise equivalent levels
CPUC	California Public Utilities Commission
CTI	Cooling Tower Institute
CTR	California Toxics Rule
Cu-Ni 70-30	Copper-Nickel alloy (70% to 30%)
Cu-Ni 90-10	Copper-Nickel alloy (90% to 10%)
CVRWQCB	Central Valley Regional Water Quality Control Board
CWA	Federal Water Pollution Control Act (“Clean Water Act”)
CWC	California Water Code (Porter-Cologne Water Quality Control Act)
CWIS	Cooling Water Intake Structure
DCPP	Diablo Canyon Power Plant
EAP	Energy Action Plan
EIR	Environmental Impact Report
ELG	Effluent Limitation Guideline
EPA	US Environmental Protection Agency

EPCM	Engineering, Procurement, and Construction Management
ERC	Emission Reduction Credit
ESGS	El Segundo Generating Station
ESHA	Environmentally Sensitive Habitat
FPS	Feet per Second
FRP	Fiber Reinforced Plastic
GIS	Gas Insulated Switchgear
gpm	Gallons per Minute
HBGS	Huntington Beach Generating Station
HEI	Heat Exchange Institute
HGS	Harbor Generating Station
HHV	Higher Heating Value
HnGS	Haynes Generating Station
hp	Horsepower
HRSG	Heat Recovery Steam Generator
ICE	Intercontinental Exchange
IM&E	Impingement mortality and entrainment
ITD	Initial temperature difference
kWh	Kilowatt-hour
LA	Load allocation
LADWP	Los Angeles Department of Water and Power
LAER	Lowest achievable emissions rate
LARWQCB	Los Angeles Regional Water Quality Control Board
LCP	Local coastal program
LHV	Lower Heating Value
MBPP	Morro Bay Power Plant
MBUAPCD	Monterey Bay Unified Air Pollution Control District
MCC	Motor Control Center
mgd	Million Gallons per Day
MGS	Mandalay Generating Station
MLPP	Moss Landing Power Plant
MW	Megawatt
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NCDC	National Climatic Data Center
NOAA	National Oceanographic and Atmospheric Administration
NO_x	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NPV	Net present value
NPV_{20}	20-year Net Present Value
NSPS	New Source Performance Standards
NSR	New Source Review
O&M	Operations and Maintenance
OBGS	Ormond Beach Generating Station
OPC	California Ocean Protection Council
PCCP	Prestressed Concrete Cylinder Pipe
PG&E	Pacific Gas and Electric

PM_{10}	Particulate Matter 10 microns or less in size
POTW	Publicly Owned Treatment Work
PPP	Pittsburg Power Plant
ppt	Parts per thousand
PWR	Pressurized Water Reactor
RBGS	Redondo Beach Generating Station
RWQCB	Regional Water Quality Control Board
SCAQMD	South Coast Air Quality Management District
SCC	California State Coastal Conservancy
SCCOOS	Southern California Ocean Observing System
SCE	Southern California Edison
SDAPCD	San Diego Air Pollution Control District
SDRWQCB	San Diego Regional Water Quality Control Board
SFBRWQCB	San Francisco Bay Regional Water Quality Control Board
SGS	Scattergood Generating Station
SIP	Policy for Implementation of Toxics Standards for Inland Surface Waters, Enclosed Bays, and Estuaries of California
SLC	California State Lands Commission
SO_2	Sulfur Dioxide
SONGS	San Onofre Nuclear Generating Station
SWRCB	California State Water Resources Control Board
TDS	Total Dissolved Solids
TMDL	Total maximum daily load
VCAPCD	Ventura County Air Pollution Control District
VFD	Variable Frequency Drive
VSP	Variable Speed Pump
WQBEL	Water quality–based effluent limits
ZLD	Zero liquid discharge

EXECUTIVE SUMMARY

1.0 BACKGROUND

The California Ocean Protection Council (OPC), created under the 2004 California Ocean Protection Act, is responsible for facilitating interagency regulatory and oversight efforts related to the protection of California's coastal resources. On April 20, 2006, the OPC adopted a resolution titled *Regarding the Use of Once-Through Cooling Technologies in Coastal Waters* ("2006 Resolution") acknowledging that steam electric power plants that withdraw large, continuous volumes of water can have a significant environmental impact on coastal resources. Further, the resolution urges state agencies to "implement the most protective controls to achieve a 90−95 percent reduction in [impingement and entrainment] impacts" and analyze the costs and constraints involved with the conversion of each once-through cooling system to an alternative technology.

This study evaluates the feasibility of impingement and entrainment control technologies that can meet the 2006 Resolution benchmark in the most cost-effective manner. Although many technologies and operational measures exist that might achieve reductions approaching the benchmark levels, the certainty of their performance at California's coastal facilities cannot be assured without a companion analysis of each location's biological characteristics. Accordingly, this study focuses on those technologies with proven performance data that demonstrate an ability to meet the benchmark reductions, without evaluating biological criteria as well. The most effective technology that can meet these criteria is closed-cycle cooling, commonly referred to as "wet" or "dry" cooling towers.

This study includes an engineering assessment and cost profile for each facility based on retrofitting once-through cooling systems to wet cooling towers. Dry systems were not considered in detail because both wet and dry cooling can meet the 2006 Resolution benchmarks, but dry systems generally present greater technical, logistical and economic constraints. Dry cooling becomes more competitive when considered for repowering projects, where the generating unit undergoes substantial modification or replacement and can more easily be configured to operate with a dry system.

Repowering is of particular interest in California, where many of the coastal power plants are 30 to 40 years old, or more, and are likely to be replaced with more efficient technologies in the coming years. Economically, it may be more practical to repower an existing facility with closed-cycle cooling rather than retrofit the existing system. A repowered facility is generally more compatible with closed-cycle technologies, operates more efficiently, emits less CO_2 per kilowatt-hour (kWh), and has a greater potential to increase operating revenues, among other benefits.

This study evaluates the cooling system's redesign only; the role of repowering, which enables consideration of a wider range of cooling options, is not addressed.

2.0 CALIFORNIA'S COASTAL POWER PLANTS

In California, reference is often made to 21 coastal power plants that operate once-through cooling systems. As of the publication of this study, only 18 of these facilities are actively generating power and withdrawing water from marine or estuarine sources. Three facilities—Humboldt Bay, Hunter's Point, and Long Beach—have ceased operations that rely on once-through cooling; Humboldt Bay and Long Beach are in the process of repowering with technologies that do not require cooling water.

The remaining 18 facilities are concentrated along the southern coastline but also extend north to the San Francisco Bay and Sacramento-San Joaquin Delta. These plants are summarized in Table ES-1 and shown in Figure ES-1 and Figure ES-2.

Of these 18 facilities, only 15 are addressed in this study. The Carlsbad Energy Center Project is intended as a replacement for the Encina Power Station using air-cooled combined-cycle units and is currently undergoing certification review by the CEC. The South Bay Replacement Project was pursuing CEC approval for a similar repowering effort at the time this study began, but the project was formally withdrawn from consideration on October 24, 2007 following the Administrative Draft's publication. Potrero Power Plant, with one active generating unit, is likely to close pending the implementation of the San Francisco Energy Reliability Project.

Table ES-1. California Power Plants with Once-Through Cooling

Facility	Source water body	Fuel type	Generating capacity (MW)	Design intake flow (mgd)
Alamitos	Los Cerritos Channel	Natural gas	1,970	1,077
Contra Costa	Sacramento/San Joaquin Delta	Natural gas	680	440
Diablo Canyon	Pacific Ocean	Uranium	2,202	2,500
El Segundo	Santa Monica Bay	Natural gas	670	424
***Encina* [a]**	*Aqua Hedionda Lagoon / Pacific Ocean*	*Natural gas*	*966*	*857*
Harbor	Los Angeles Harbor	Natural gas	462	108
Haynes	Long Beach Marina	Natural gas	1,606	966
Huntington Beach	Pacific Ocean	Natural gas	1,013	516
Mandalay	Channel Islands Harbor	Natural gas	573	253
Morro Bay	Morro Bay Harbor	Natural gas	912	668
Moss Landing	Elkhorn Slough/Moss Landing Harbor	Natural gas	2,484	1,224
Ormond Beach	Pacific Ocean	Natural gas	1,613	688
Pittsburg	Sacramento/San Joaquin Delta	Natural gas	1,370	495
***Potrero* [a]**	*San Francisco Bay*	*Natural gas*	*366*	*226*
Redondo Beach	Santa Monica Bay	Natural gas	1,343	871
San Onofre	Pacific Ocean	Uranium	2,254	2,574
Scattergood	Santa Monica Bay	Natural gas	803	496
***South Bay* [a]**	*San Diego Bay*	*Natural gas*	*706*	*601*

[a] Potrero, South Bay, and Encina are not evaluated in this study.
mgd = million gallons per day.

Figure ES-1. North Coast Power Plants

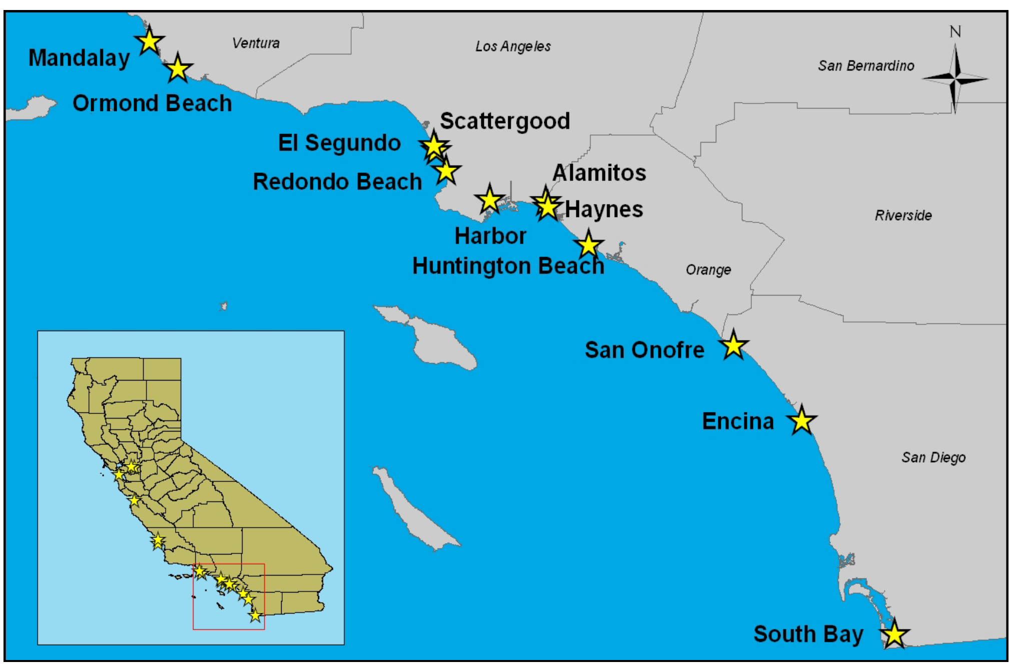

Figure ES-2. South Coast Power Plants

3.0 REGULATORY FRAMEWORK

Retrofitting to a closed-cycle system potentially creates conflicts or inconsistencies with other state and local regulations. This study reviews regulatory concerns in two ways: first, at the programmatic level across the entire state to assess potential conflicts that might follow a retrofit; and second, in determining whether any regulations or standards might preclude the installation of a wet cooling tower system at an individual site. Retrofitting is consistent with the OPC's 2006 Resolution and other state agency policies that discourage the use of seawater for once-through cooling purposes. Converting to a wet cooling tower system might involve other statewide regulatory issues, including:

- Despite slight losses in generating efficiency, the California Energy Action Plan (EAP) is not expected to preclude cooling system retrofits, since the first priorities are energy conservation, development and use of renewable resources, ensuring reliable generation, and distribution system reliability. In addition, conversion is consistent with EAP's goal of enhanced environmental protection.
- Conversion is consistent with the California Coastal Commission's goal of conserving marine resources but may necessitate site-specific mitigation to address requirements to protect visibility, recreation, habitat, and other coastal resources.
- Conversion will affect surface water discharge characteristics and require modification of National Pollutant Discharge Elimination System (NPDES) wastewater discharge permits for each facility. A wet cooling system reduces the wastewater discharge volume by 90−95 percent but may increase the concentrations of some pollutants contained therein. While pollutant mass emissions are not likely to increase as a result of retrofitting, concentration changes may create conflicts with effluent limitations and require additional treatment prior to discharge or alternative discharge methods.
- Clean Air Act permitting requirements are not likely to preclude conversion. Conversions will, however, likely trigger new source review at some facilities due to increased particulate emissions from cooling tower exhaust. This would necessitate facilitywide evaluation of control technologies and possibly require new controls. In particulate nonattainment areas, facilities may have to acquire particulate emission credits to offset the increases in emissions from cooling towers.
- Conversion will require California Environmental Quality Act (CEQA) compliance, although the level of analysis will vary by facility. As part of the CEQA process, a range of mitigation measures will likely be required to address effects on physical, biological, cultural, and social resources.

4.0 EVALUATION OF OTHER TECHNOLOGIES

While the primary focus of this study is retrofitting with wet cooling systems, the study also includes a *limited* review of other technologies that could be used to meet the performance benchmarks included in the 2006 Resolution. Dry cooling systems can effectively eliminate the withdrawal of surface water by using air to condense steam. As noted in Section 1.0, however, dry cooling was not considered in detail in this study because, in a strictly retrofit application, the logistical constraints and total cost will be greater, often significantly so, than a comparable wet cooling system retrofit.

Fine-mesh wedgewire screens were found to be a viable, less costly option for two facilities, although a more detailed, site-specific analysis would need to be completed to confirm their performance at each location. Use of this technology in coastal waters has not been evaluated in detail, although further research into different design configurations may allow for their deployment in coastal waters at some point in the future.

Variable speed pumps/variable frequency drives allow a facility to moderate its cooling water intake flow depending on seasonal and operational conditions. The maximum benefit is typically limited to a 50 percent reduction of impacts (depending on intake flow) but actual reductions will based on the time of year and generating load of the facility. Variable speed pumps are technically feasible at all facilities; any benefit, however, is dependent on the frequency and degree to which flow can be reduced without impacting operations.

A number of plants that withdraw water directly from the Pacific Ocean in southern California have offshore intake structures with velocity caps. These offshore structures may limit impingement and entrainment compared to a conventional onshore intake location, but sufficient biological data were not available to determine site-specific performance. In addition, several state agencies have been hesitant to state conclusively that offshore intake locations are sufficient to meet the best technology available (BTA) standard in Section 316(b) of the Clean Water Act.

Where available, reclaimed water was considered as a potential source of makeup water for wet cooling towers, or, at a few facilities, as a direct replacement for the existing once-through cooling water source. Obtaining reclaimed water requires the construction of transmission pipelines and may require additional treatment prior to use in a cooling tower. These factors are likely to increase the total cost of a wet cooling tower installation. Use of reclaimed water can yield additional benefit such as avoiding conflicts with water discharge limits and reduced air emissions of particulates.

5.0 STUDY FRAMEWORK AND METHODS

This study specifically evaluates the site-specific technical and logistical feasibility and cost of wet cooling towers at 15 of the 18 coastal power plants listed in Table ES-1. The intent is to establish a more precise understanding of the engineering options and associated costs of a once-through cooling system retrofit, and the factors that influence those costs, in order to assist state agencies in the regulatory development process as it moves forward. This study does not reach any overall conclusions regarding a site-specific feasibility determination, such as that which would be required in a CEQA analysis.

For each facility, a conceptual design of a wet cooling tower system was developed that would meet the minimum identified requirements at each location. This "preferred option" is the design that can reduce impingement and entrainment impacts by 90 percent or more and can comply with site-specific restrictions in the most cost-effective manner.

The preferred option is based on accepted industry standards and practices, as well as best professional judgment when evaluating the following broad criteria:

5.1.1 ENGINEERING CONSTRAINTS

1. **Technical / Logistical.** The availability of sufficient space is the most limiting factor in a wet cooling tower retrofit analysis. As part of this process, a conceptual design of the cooling tower system was developed within the logistical constraints identified at each facility. At most locations, space is available but may require relocation of existing structures. Optimal siting generally places wet cooling towers at a reasonable distance from the generating units to minimize costs. This was not always possible because of land availability and conflicts with other land uses at or immediately adjacent to the site. Other factors, such as integration with the generating unit and conflicts with other facility systems, were also evaluated.

2. **Regulatory / Local Use.** This study evaluated local land use policies and public health and safety requirements that might affect the design or feasibility of wet cooling tower systems. Where necessary to ensure compliance with other regulatory programs, mitigation measures were incorporated into the tower design, e.g., noise and plume abatement.

5.1.2 COST ESTIMATE

Comprehensive cost estimates were based on four categories: (1) initial capital and startup, (2) operations and maintenance, (3) shutdown revenue loss, and (4) energy penalty. In the study, all capital costs were assumed to be amortized over a 20-year period based on an assumed average lifespan for saltwater towers before significant repair or replacement costs are incurred. The basis does not reflect the potential lifespan of the individual facility or generating unit. The results are presented as net present costs and annualized costs (in current dollars) over this 20-year period and include:

1. **Initial capital.** This category addresses all construction and design-related activities required for a wet cooling tower retrofit, including the following:
   - Cooling tower costs. Cooling tower construction costs were obtained from cooling tower vendors based on the conceptual designs.
   - Civil, structural, mechanical, and electrical costs. These costs are associated with the supporting structures and equipment necessary to integrate the cooling towers with the power generating units.
   - Indirect costs. These are other costs associated with cooling tower management, including start-up, permitting, engineering, etc. These costs are not itemized but estimated as 25 percent of all direct costs (cooling tower plus civil, structural, mechanical, and electrical).
   - Condenser modification. This cost is an allowance for a facility to reinforce its condenser in order to accommodate the higher circulating water pressures that can result from converting to wet cooling towers. This cost was estimated at 5 percent of all direct costs.
   - Contingency. This is an allowance for project unknowns, accidents, and delays that often affect complex construction projects. Based on the level of detail available for this study and following professional estimator guidelines, the contingency cost is calculated as 25 percent of all direct, indirect, and condenser modification costs.
2. **Operations and maintenance.** This category reflects the annual cost associated with maintaining wet cooling towers over a 20-year period. Based on information from cooling tower vendors, it is calculated as a fixed amount per gallon per minute of cooling system flow.
3. **Shutdown costs.** This category reflects the lost revenue resulting from a necessary cessation of power generation during the construction and tie-in period. For Diablo Canyon and San Onofre, this is a significant cost component because of their size and high capacity utilization rate. Shutdown losses were also estimated for Haynes and Moss Landing, although the total value is substantially less. At all other facilities, the seasonal or infrequent operation of individual units allows construction and integration to be completed while units are not operational.
4. **Energy penalty.** The energy penalty is based on two components: the increased electrical usage associated with the operation of tower fans and pumps, and the reduced generating efficiency associated with a wet tower retrofit. The manner in which a facility chooses to adapt to these changes will influence the actual cost of the energy penalty. In some cases a facility may opt to absorb the net loss of revenue-generating electricity. Natural gas-fired units may be able to increase the turbine firing rate, or thermal input, to make up some, or all, of the net generating shortfall—in which case the energy penalty cost is the value of the additional fuel that is consumed.

   Nuclear facilities such as Diablo Canyon (Pacific Gas & Electric [PG&E]) and San Onofre (Southern California Edison [SCE]) generally cannot modify thermal inputs to the system because of safety and design constraints. As investor-owned utilities, PG&E and SCE must compensate for the net generating shortfall by purchasing replacement power from other sources or on the open market, the cost of which is often much higher than the nuclear cost of generation

6.0 RESULTS

This study shows that retrofitting existing once-through cooling systems with the preferred wet cooling design could be technically and logistically feasible at 12 of the 15 active coastal power plants (Table ES-2).

Table ES-2. Feasibility Summary

Infeasible	Feasible	
• El Segundo • Ormond Beach • Redondo Beach	• Alamitos • Diablo Canyon • Haynes • Mandalay • Moss Landing • San Onofre	• Contra Costa • Harbor • Huntington Beach • Morro Bay • Pittsburg • Scattergood

Retrofitting to wet cooling towers is not feasible at Redondo Beach because of its immediate proximity to office buildings and residential areas. Compliance with local use requirements would be unlikely.

For two other facilities—El Segundo and Ormond Beach—the preferred option could not be configured to meet the minimum site constraints. At both locations, interference from a wet cooling tower's visible plume with nearby flight operations made it probable that plume-abated towers would be required. An acceptable configuration could not be designed for either location due to limited space availability and potential interference with other major structures. Because the plume abatement requirement could not be confirmed for either facility, the study proceeded with an analysis of conventional cooling towers for El Segundo and Ormond Beach, which are logistically feasible at both sites may face other obstacles.

For other facilities, wet cooling tower retrofits are technically and logistically feasible based on the study's criteria but may have to overcome other impediments. At Diablo Canyon, the constraints of the existing site and the disruption caused by a wet cooling tower retrofit will require both units to be offline for 8 months or more. At San Onofre, a retrofit would require additional regulatory approval because of potential effects on sensitive plant species and the disruption to environmentally sensitive habitats. At Moss Landing and other central coast facilities, particulate emission increases from a wet cooling tower may require the facility to purchase emission reduction credits, which may be costly, if they are available at all.

Table E-3 summarizes 20-year annualized cost estimates for 11 of California's coastal facilities where cooling tower retrofits are considered technically and logistically feasible.[1] Per megawatt-hour costs are presented based on rated capacities and 2006 net output for each generator category. Table ES-4 presents the same costs for each facility.

In sum, the annual cost to retrofit the 11 facilities noted above with wet cooling towers translates to 0.45 cents per kilowatt hour (kWh) based on the facilities' collective generating capacity. Compared with their 2006 generating output, the annual cost translates to 1.16 cents/kWh. If passed entirely to the ratepayer, retrofit costs would represent an increase ranging from 3.5 to 9.0 percent based on the 2006 average end-use retail cost of 12.93 cents/kWh in California.[2]

Table ES-3. Annualized Cost Summary—Generating Sector

Facility category	20-year total annualized cost [a],[b] ($)	Rated capacity (GWh)	Cost per MWh ($/MWh)	2006 net output (GWh)	Cost per MWh ($/MWh)
Nuclear [c]	442,600,000	39,017	11.34	34,873	12.69
Steam turbine [d]	113,600,000	75,257	1.64	8,304	14.86
Combined-cycle [e]	30,400,000	16,557	1.24	7,537	2.73
All facilities	**586,600,000**	**130,831**	**4.48**	**50,714**	**11.57**

[a] 20-year annualized cost of all initial capital and startup costs, operations and maintenance, and energy penalty. Value represents the total annualized cost for all facilities in each category.

[b] Annual costs do not include any revenue loss associated with shutdown during construction. This loss is incurred in the first year of the project but not amortized over the 20-year project life span. Estimates of shutdown losses were developed for the following facilities:

Diablo Canyon: $ 727 million
San Onofre: $ 595 million
Haynes: $ 5 million
Moss Landing: $ 2 million

[c] Diablo Canyon and San Onofre

[d] Alamitos, Contra Costa, El Segundo (Units 3 & 4 only), Haynes (Units 1, 2, 5, & 6 only), Huntington Beach, Mandalay, Moss Landing (Units 6 & 7 only), Pittsburg, and Scattergood.

[e] Harbor, Haynes (Unit 8 only), and Moss Landing (Units 1 & 2 only).

GWh = gigawatt hour
MWh = megawatt hour

[1] Costs for Morro Bay are not included in either table because the analysis was developed based on the repowering project the previous owner (Duke Energy) had proposed for the facility. Cost estimates, therefore, are not directly comparable to the retrofit analyses conducted for the other coastal facilities. Based on a previous analysis prepared by Tetra Tech, Inc. for the Central Coast Regional Water Quality Control Board in 2002 and the general methodology of this study, the updated annual cost for Morro Bay is $9.6 million.

[2] *California Average Retail Price of Electricity to Ultimate Customers—All Sectors (Residential, Commercial Industrial) Year to Date through October 2006.* US Energy Information Agency, 2006.

Table ES-4. Annualized Cost Summary—Facility

Facility	Category [a]	20-year annualized cost [b],[c] ($)	Rated capacity (GWh)	Cost per MWh ($/MWh)	2006 net output (GWh)	Cost per MWh ($/MWh)
Alamitos	ST	25,400,000	17,082	1.49	1677	15.15
Contra Costa	ST	9,900,000	5,957	1.66	139	71.32
Diablo Canyon	N	233,700,000	19,272	12.13	18,465	12.66
Harbor	CC	2,700,000	2,059	1.31	107	25.21
Haynes [d]	CC	6,000,000	5,037	1.19	2065	2.91
Haynes [d]	ST	13,900,000	9,145	1.52	2263	6.14
Huntington Beach	ST	15,400,000	7,709	2.00	991	15.54
Mandalay	ST	5,800,000	3,767	1.54	236	24.58
Moss Landing [e]	CC	11,900,000	9,461	1.26	5,364	2.22
Moss Landing [e]	ST	21,700,000	12,299	1.76	1044	20.81
Pittsburg	ST	12,700,000	12,264	1.04	457	27.79
San Onofre	N	208,900,000	19,745	10.58	16,408 [f]	12.73
Scattergood	ST	18,600,000	7,034	2.64	1,498	12.42
All facilities		**586,600,000**	**130,831**	**4.48**	**50,714**	**11.57**

[a] CC = combined-cycle; ST = simple cycle steam turbine (natural gas); N = nuclear-fueled steam turbine
[b] 20-year annualized cost of all initial capital and startup costs, operations and maintenance, and energy penalty.
[c] Annual costs do not include any revenue loss associated with shutdown during construction. This loss is incurred in the first year of the project but not amortized over the 20-year project life span. Estimates of shutdown losses were developed for the following facilities:

Diablo Canyon:	$ 727 million
San Onofre:	$ 595 million
Haynes:	$ 5 million
Moss Landing:	$ 2 million

[d] Haynes operates one combined-cycle unit (Unit 8) and four simple cycle units (Units 1, 2, 5, & 6). Costs are specific for each unit type; facility-wide cost is the sum of both categories.
[e] Moss Landing operates two combined-cycle units (Unit 1 & 2) and two simple cycle units (Units 6 & 7). Costs are specific for each unit type; facility-wide cost is the sum of both categories.
[f] 3-year average output for SONGS.
GWh = gigawatt hour
MWh = megawatt hour

1. INTRODUCTION

1.0 BACKGROUND

Steam-powered turbines remain the principal technology used to generate electricity in the United States, accounting for nearly three-quarters of the total annual output. Because a limited amount of electricity can be extracted from steam, a balance of waste heat remains that must be removed from the system to maintain optimal efficiencies. The most basic approach to remove waste heat has been to circulate large volumes of water through a condenser and back to the water body, where the heat is rejected to the surrounding environment. These single-pass, or once-through, systems have been the most commonly used cooling methods because of their relatively low capital and operating costs and, in most cases, their ability to provide the lowest cooling temperature, which enables electricity to be generated more efficiently.

There are currently more than 1,200 steam-generating units using this cooling method in the United States. Together, these units account for 65 percent of the steam electric capacity and maintain the capability of withdrawing up to 177,000 million gallons per day (mgd) from surface water sources, the largest categorical use of surface water. California's coastal power plants alone maintain the capacity to withdraw more than 13,000 mgd.

Although once-through cooling systems continue to predominate, various trends over the last several decades have encouraged the development and implementation of alternative technologies that can reduce or eliminate the adverse impacts associated with once-through cooling. Increased competition for water resources, whether for potable or recreational purposes, has expanded the use of cooling methods that rely on substantially less water (evaporative cooling) or effectively eliminate the use of water altogether (dry cooling). Technological advances such as combined-cycle systems generate electricity more efficiently by capturing waste heat from gas combustion turbines to generate steam, thus requiring less cooling water per megawatt of capacity. Finally, the expanding awareness and general consensus that once-through cooling water systems can have a significant adverse impact on aquatic environments has contributed to increased efforts on the part of state and federal agencies to address these effects through regulatory measures.

2.0 PURPOSE

The California Ocean Protection Council (OPC), created under the 2004 California Ocean Protection Act, is charged with facilitating interagency efforts as they relate to the protection of California's coastal resources. Specifically, the OPC is tasked with the following:

- Coordinating activities of ocean-related state agencies to improve the effectiveness of state efforts to protect ocean resources within existing fiscal limitations.
- Establishing policies to coordinate the collection and sharing of scientific data related to coast and ocean resources between agencies.

- Identifying and recommending to the Legislature changes in law.
- Identifying and recommending changes in federal law and policy to the Governor and Legislature.

On April 20, 2006, the OPC adopted a resolution titled Regarding the Use of Once-through Cooling Technologies in Coastal Waters that acknowledges that power plants with once-through cooling systems, through their high use of coastal waters, can have a significant environmental impact on coastal resources. Further, the resolution urges various state agencies to "implement the most protective controls to achieve a 90–95 percent reduction in impacts" and analyze the costs and constraints involved with the conversion of each once-through cooling system to an alternative technology (OPC 2006). Partner agencies in this effort include the California Coastal Commission (CCC), Bay Conservation and Development Commission (BCDC), California Energy Commission (CEC), State Water Resources Control Board (SWRCB), State Lands Commission (SLC), and California Public Utilities Commission (CPUC).

This study has been undertaken to support the efforts of these agencies in determining whether California's once-through cooling facilities can implement alternative technologies that would allow them to reduce adverse impacts to the level set forth in the OPC resolution. The principal reasons for this study and its focus are twofold.

First, the decision to modernize an existing facility's once-through cooling system requires careful consideration of a broad range of issues, especially when retrofitting to closed-cycle technologies. These technologies can dramatically reduce the adverse effects to California's coastal waters attributed to once-through cooling systems but may create other environmental effects, such as increased greenhouse gas emissions, that could conflict with other regulations. The duration a facility may be offline during construction may strain local grid reliability requirements, especially for large baseload facilities. In addition, the associated costs for some technologies, both initial and long-term, may be significant and may not be economically practical for many of California's aging steam facilities.

Second, previous efforts to quantify the technical feasibility and costs for broad groups of facilities have relied upon models and case studies to develop assumptions that could then be extrapolated based on a common metric. These studies are useful for understanding broader issues and, in some cases, may be an acceptable method for estimating facility-level costs, but often underestimate or ignore important factors that heavily influence a technology's design, feasibility, and cost at a particular location. This effort attempts to more accurately account for the unique conditions and requirements at each of California's coastal facilities and quantify their impact on the overall evaluation.

It is important to note that the conclusions reached by this study are driven by the baseline assessment of technical and logistical feasibility; that is, could a closed-cycle cooling system be installed at each facility and at what cost. They do not constitute a final determination of what is "feasible" at any individual facility under the California Environmental Quality Act (CEQA), which is defined as "capable of being accomplished…taking into account social, environmental, economic and technological factors." It is the OPC's intention that this study will be used as an important component of the state's efforts to address cooling water impacts and provide the necessary information to formulate broader conclusions about the overall feasibility of alternative cooling systems.

References to feasibility in this study are limited to technical and logistical considerations, except as noted. Additional information describing the steps used in this evaluation is contained in Section 4.0 of this chapter.

3.0 ONCE-THROUGH COOLING IMPACTS

Assessing adverse impacts due to cooling water withdrawals is a complex undertaking, one that requires detailed information about the facility in question and the ecology of its source water. Many site-specific factors influence the level of impact a once-through system may have; for example, two systems operating identically, but in different locations, may have very different effects on their surroundings. While there may be variability from one facility to another, the consensus among regulatory agencies at both the state and federal levels is that once-through systems contribute to the degradation of aquatic life in their respective ecosystems. In its 2005 report, the CEC concluded once-through cooling systems were “partly responsible for ocean degradation” and contributed to declining fisheries and impaired coastal habitats through the intake of large volumes of water and the discharge of elevated-temperature wastewater (CEC 2005).

Most facilities that obtain cooling water from surface water sources use some method of primary screening to prevent large objects from being drawn through the cooling system, where they may clog or damage sensitive equipment. These screens typically have mesh panels with slot sizes ranging from 3/8 inch to 1 inch and are rotated periodically or removed to clean off any debris, including aquatic organisms.

3.1 IMPINGEMENT

Impingement occurs when organisms are trapped against the screen as a result of the force of the intake water and are unable to escape. Impinged organisms may asphyxiate if the force of the oncoming water prevents their gills from operating normally. Starvation or mortality from fatigue may result if organisms are held against the screen for prolonged periods. Even those organisms that are able to escape may suffer physical injuries, such as descaling, that make them more susceptible to death or predation. Impingement does not, however, always result in the death of the organism. Hardier species, particularly larger ones in their adult phases, are sometimes capable of withstanding the stresses of impingement. Modifications to screening systems may enable the capture and release of organisms before mortality or significant injury can occur.

Susceptibility to impingement is dependent on many factors, not the least of which is the target species and its inherent ability to out swim the current induced by the intake system or its ability to withstand any physical injury that may occur from interaction with the screens. Survival, or avoidance of impingement altogether, is also influenced by the life stage and general health of the target organism. Environmental factors, such as relative areas of light and dark in the vicinity of the intake structure, may also contribute to an increased rate of impingement by triggering behavioral responses. Changes in temperature beyond the optimal range for some species may induce lethargy and impair the organism’s ability to avoid or escape from the intake structure. In some cases, these behavioral responses can be exploited to prevent organisms from being impinged, although they are highly species specific and limited in their application.

EPA, in its development of national regulations addressing impingement and entrainment impacts, considered an "impingeable" organism to be one that is free swimming and larger than 3/8 inch in size (USEPA 2002). This generally applies to organisms that are juveniles or, in certain species, adults.

3.2 ENTRAINMENT

Entrainment is the action of drawing smaller objects through the entire cooling water system, including the pumps and condenser tubes, and discharging them along with the cooling water and other plant wastes. Organisms susceptible to entrainment through cooling water systems are among the most fragile in the aquatic community because of their relatively small size (less than 3/8 inch) and life stage (typically fish eggs and larvae). Planktonic organisms such as these cannot independently escape the influence of an intake system and are instead reliant upon screening mechanisms or other methods to prevent their intake.

Organisms that find themselves entrained through a power plant cooling system will be subjected to dramatic changes in pressures as they pass through the pump and condenser. Water temperatures will rapidly increase by 10 to 25° F, or more, and decrease upon discharge and mixing with the receiving water. Physical injury may occur from the interaction with mechanical equipment and the shearing forces of pumps. Chemicals used to control biofouling in the system, such as chlorine, further complicate the ability of organisms to survive entrainment until they are discharged back to the water body.

There is some disagreement within the stakeholder community over the ability of certain organisms to survive entrainment and maintain their long-term viability. Limited data are available that can reliably demonstrate the survival of entrained organisms in relation to the number entrained overall. For this reason, EPA assumed 100 percent mortality for entrained organisms during the development of regulations addressing cooling water impacts (USEPA 2004). Accordingly, the preferred method to reduce the adverse effects of entrainment is to prevent the interaction of susceptible organisms and the cooling system altogether. This can be accomplished in one of two ways: the use of a barrier technology with pores small enough to exclude entrainable organisms, or by reducing the volume of water withdrawn by the facility.

3.3 COASTAL POWER PLANTS IN CALIFORNIA

There are currently 18 large steam electric power plants in California that use once-through systems. Most of these facilities are concentrated in southern California and withdraw cooling water directly from the Pacific Ocean or nearby estuaries. Together, these facilities are permitted to withdraw more than 13,000 mgd from California's coastal waters and discharge the same volume back to the source water at an elevated temperature. Many of the generating units at these stations were first placed into service decades ago; the average age of coastal fossil fuel units in California is 40 years. In part because of their age and lower efficiency, these units are dispatched less frequently than newer, more efficient stations and may only be operational for a few weeks or months of the year. General information about California's coastal facilities is summarized in Table 1-1. The general location of each facility is shown in Figure 1-1 and 1-2.

Table 1-1. California Coastal Facilities

Facility name (Location)	Design flow (mgd)	Water body type	Unit	In-service year	2001–2006 capacity utilization (%)	Dependable capacity (MW)
Alamitos Generating Station (Long Beach)	1,077	Estuary	1	1956	6.7	175
			2	1957	8.7	175
			3	1961	27.7	326
			4	1962	20.8	324
			5	1969	27.4	485
			6	1966	22.2	485
Contra Costa Power Plant (Antioch)	440	Estuary	6	1964	16.4	340
			7	1964	23.1	340
Diablo Canyon Power Plant (Avila Beach)	2,500	Ocean	1	1985	89.0	1,103
			2	1986	89.3	1,099
El Segundo Generating Station (El Segundo)	424	Ocean	3	1964	19.4	335
			4	1965	24.8	335
Encina Power Station (Carlsbad)	857	Ocean	1	1954	18.7	107
			2	1956	21.0	104
			3	1958	25.1	110
			4	1973	36.0	300
			5	1978	33.0	330
Harbor Generating Station (Los Angeles)	108	Enclosed bay / harbor	CC	1994	20.5	227
Haynes Generating Station (Long Beach)	966	Estuary	1	1962	20.5 [a]	1,606 [a]
			2	1963		
			5	1966		
			6	1967		
			8	2005		
Huntington Beach Generating Station (Huntington Beach)	516	Ocean	1	1958	31.5	215
			2	1958	31.0	215
			3	2002	9.6	225
			4	2003	8.5	225
Mandalay Generating Station (Oxnard)	253	Enclosed bay / harbor	1	1959	20.6	218
			2	1959	23.4	218
Morro Bay Power Plant (Morro Bay)	552	Estuary	3	1962	18.8	300
			4	1963	18.8	300
Moss Landing Power Plant (Moss Landing)	1,224	Enclosed bay / harbor	1	2002	41.1	540
			2	2002	41.4	540
			6	1967	19.7	702
			7	1968	24.2	702
Ormond Beach Generating Station (Oxnard)	688	Ocean	1	1971	16.3	806
			2	1973	17.7	806

Facility name (Location)	Design flow (mgd)	Water body type	Unit	In-service year	2001–2006 capacity utilization (%)	Dependable capacity (MW)
Pittsburg Power Plant (Pittsburg)	495	Estuary	5	1960	23.7	325
			6	1961	21.0	325
			7	1972	23.5	720
Potrero Power Plant (San Francisco)	226	Estuary	3	1956	38.1	207
Redondo Beach Generating Station (Redondo Beach)	871	Ocean	5	1954	4.9	179
			6	1957	5.6	175
			7	1967	22.2	493
			8	1967	19.6	496
San Onofre Nuclear Generating Station (San Clemente)	2,574	Ocean	2	1983	86.8	1,127
			3	1984	79.4	1,127
Scattergood Generating Station (Los Angeles)	496	Ocean	1	1958	22.1 [a]	803 [a]
			2	1959		
			3	1974		
South Bay Power Plant (Chula Vista)	532	Estuary	1	1960	39.8	136
			2	1962	38.7	136
			3	1964	27.9	210
			4	1971	6.8	214

[a] Facility-wide totals. Unit-level data unavailable.

Figure 1-1. North Coast Power Plants

Figure 1-2. South Coast Power Plants

4.0 FRAMEWORK

This study evaluates the logistical, regulatory, and economic factors that arise when a facility modifies its cooling water system by implementing technology-based measures designed to achieve the OPC performance benchmark. Previous attempts to quantify the cost and complexity associated with retrofitting an existing cooling water system have been based on broad assumptions and extrapolated from models or case studies. Because the circumstances and operating limitations can vary widely from facility to facility, this approach can have the effect of underestimating or overestimating the true costs and logistical considerations of an actual retrofit scenario.

This report moves beyond a model-based approach by using facility-specific data to develop comprehensive cost and engineering profiles that are unique to each of California's affected facilities. It is not, however, intended to be exhaustive in terms of the many obstacles that may exist and the different technology configurations that can be evaluated, nor can it be considered a substitute for the more rigorous engineering assessment that would be conducted prior to the implementation of one of the evaluated options. Instead, the intent is to establish a more precise understanding of the engineering options and associated costs of a once-through cooling system retrofit, and the factors that influence those costs, in order to assist state agencies in the regulatory development process as it moves forward.

4.1 TECHNOLOGY EVALUATION

The technologies considered for this study are limited to those with a proven capability to achieve measurable and consistent reductions of impingement mortality or entrainment (IM&E), or both. These reductions are generally independent of the biological makeup of the affected water body and can be evaluated based on quantifiable physical and logistical criteria.

The exclusion of any technology from detailed evaluation in this study does not correspond to a determination of the potential effectiveness it may have in achieving comparable IM&E reductions. Individual facility conditions may allow for deployment of an alternate technology, but an assessment of its effectiveness cannot be made without the rigorous biological analysis that must complement the logistical evaluation of the local environment. Some of these technologies are discussed further in Chapter 2.

Taking into account only physical and logistical factors, this study evaluates each facility with respect to technologies that can achieve a 90–95 percent reduction of IM&E impacts as discussed in the 2006 OPC resolution. Dry cooling technologies were not considered for this study because of the numerous difficulties associated with their use in a purely retrofit application (see Chapter 4). Thus, this study primarily focuses on the technical and logistical considerations associated with retrofitting an existing once-through system with wet cooling towers (evaporative cooling).

For a particular facility and technology, the determination of feasibility was based on the technology's ability to satisfy the following general criteria as they apply to that facility:

1. *Logistical Feasibility.* Are there physical constraints or other logistical considerations that would preclude its successful use at the particular location? Examples include lack of sufficient space or incompatibility with the configuration of the existing facility or its cooling water system.
2. *Operational Feasibility*. Would the technology conflict with the facility's design criteria and operating limits? In some cases, retrofitting to closed-cycle cooling may raise turbine backpressures to unacceptable levels and place undue strain on turbine and condenser equipment. Variable speed pumps can reduce intake volume from 30 to 40 percent and achieve a similar reduction of IM&E impacts, but this benefit cannot be realized unless operating conditions allow reduced circulating water flows. If the periods in which variable speed pumps operate at their maximum capacity overlap with seasonal spawning or migration times, any potential benefits may be negated.
3. *Local Use Restrictions.* Are there local planning and zoning ordinances, such as those that relate to building height, noise, or public safety, that would affect the design or configuration of the technology so as to preclude its use? If so, can the technology be configured differently to avoid conflict?
4. *Aesthetic and Environmental Restrictions.* What impacts will the operation of the technology have on the surrounding environment? Are there state or federal regulations that restrict activities to protect public beneficial uses or endangered or threatened species? Will the facility be able to comply with new and revised regulatory requirements that address issues such as increased air emissions and altered wastewater discharges?

The first two criteria (logistical and operational feasibility) are the most critical for consideration in this study; a technology's inability to meet either is considered a "fatal flaw" for that particular facility and precluded any further evaluation. The second two criteria were primarily used to guide the selected technology's design and configuration at each location. In some cases, local use or environmental restrictions would preclude a technology's deployment at a particular location analysis despite the ability, from a logistical perspective, to install and operate that technology at a particular location.

For the wet cooling tower retrofit analysis, these criteria were used to develop a "preferred option" for each facility based on the minimum identified requirements and assumptions used in this study (see Chapter 5). Feasibility determinations are based on the preferred option's ability to satisfy these requirements.

At Redondo Beach Generating Station, for example, sufficient space exists to accommodate wet cooling towers, but the proximity to office buildings and residential areas, and the general approach to development taken by the city of Redondo Beach, creates a regulatory and zoning scenario in which compliance with public health, noise and aesthetic restrictions is highly unlikely. Thus, this study concludes that wet cooling towers are infeasible at this location; a detailed analysis is not developed.

In some cases, the preferred option is based on best professional judgment and the presumed requirements at a particular location in lieu of definitive guidelines. The proximity of El Segundo Generating Station and Ormond Beach Generating Station to airport facilities (Los Angeles International and Pt. Mugu Naval Air Station, respectively) would seem to require plume abatement technologies to avoid interference with flight operations, but no specific mandate could be confirmed. The preferred option (plume-abated towers) for each facility requires a larger available area than would be required for conventional (non plume-abated) towers, but because space is limited at each location, cannot be configured to meet the design criteria.

This study considers wet cooling tower retrofits at El Segundo and Ormond Beach to be infeasible because the preferred option is unavailable, although the discussion chapters for each facility do include an engineering and cost analysis based on conventional towers. This is provided because it could not be determined whether the appropriate regulatory agency would absolutely require the preferred option.

4.2 RETROFIT VS. REPOWER

In the context of this study, the term *retrofit* describes the conversion of an existing cooling water system to incorporate a new technology (or technologies) designed to reduce IM&E impacts to the benchmark levels set forth in the OPC resolution. Elements that may be modified or replaced as part of a retrofit include the intake screens, circulating water pumps and piping, and intake location, in addition to the new technology itself. Unless specifically required, upgrades to or replacements of power generation components (mainly boilers and turbines) were not considered as long as the installation of the new technology would not result in a detrimental effect on the ability of these components to function within their original design tolerances.

By contrast, the term *repower* as it applies in this context is a more comprehensive overhaul to a steam-generating unit. Repowering typically involves the replacement of, or substantial upgrade to, the principal generating components—specifically the boiler, turbine, and condenser. These improvements often involve the installation of more modern and efficient equipment, such as combustion turbines and heat recovery steam generators (HRSGs). When viewed in conjunction with a broader repowering project, the options to retrofit the cooling water system with a desirable technology become more numerous and more economically practical. Elements that may have been problematic in a retrofit scenario can be addressed more readily when they are considered as part of the initial design. This study does not evaluate alternative cooling system technology options as they might apply to a repowering project because the decision to repower a particular unit is driven, in part, by external factors, such as market conditions, corporate strategy, and contractual obligations, which are beyond the scope of this report.

Repowering is of particular interest in California, where many of the coastal power plants are 30 to 40 years old, or more, and are likely to be replaced with more efficient technologies in the coming years. Economically, it may be more practical to repower an existing facility rather than retrofit the existing cooling system. A repowered facility is generally more compatible with closed-cycle cooling technologies, operates more efficiently, emits less CO_2 per kWh, and has a greater potential to increase operating revenues, among other benefits. Figure 1-3 shows the relative CO_2 emissions from an average retrofitted unit and a new combined cycle unit.[1] Figure 1-4 shows the difference in fuel-cost-to-gross-revenue ratio for the same facilities.

Examples of repowering projects and cooling system retrofits are discussed in Chapter 6.

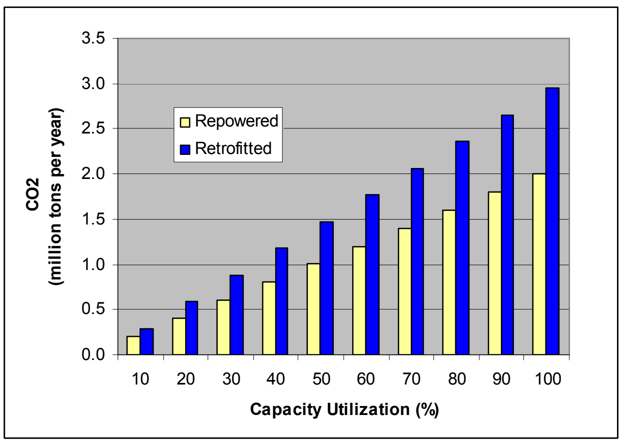

Figure 1-3. Annual CO_2 Emissions

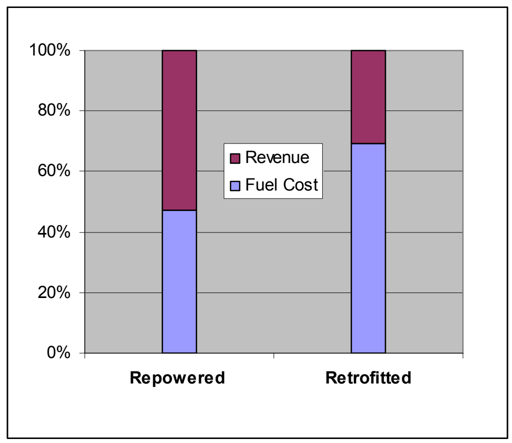

Figure 1-4. Fuel Cost to Revenue Ratio

[1] Each unit with a generating capacity of 575 MW. Heat rates: 10,000 BTU/kWh (retrofitted); 6,800 BTU/kWh (repowered).

5.0 COST EVALUATION

Using the OPC resolution as the performance benchmark for a selected technology, this study evaluates the cost of potential retrofit options on a "most practical/least costly" basis. Essentially, this approach assesses the options available to a facility that allow it to achieve the benchmark at the lowest reasonable cost, while at the same time acknowledging other technology options or configurations that may enable a facility to exceed the benchmark reduction levels, but at a higher cost. The OPC recognizes that site-specific considerations or other regulatory concerns may make these additional measures equally, or more, desirable than the lowest-cost option.

Comprehensive cost estimates for this study are unique for each location and based on specific data provided by the facility. In some cases, the data, given its level of detail and usefulness, limited the development of a more precise estimate and may not fully reflect the design parameters of the facility. Capital costs are developed for each facility based on budgetary quotes provided by vendors that supply the various technologies to power plants throughout the country. Annual costs for operations and maintenance (O&M) are calculated based on the approximate life span of the selected technology, vendor information, and best professional judgment (BPJ).

Energy penalty costs, those that result from the changes to the overall efficiency of a facility, are developed based on the design specifications provided by each facility. The methodology used to develop the design configuration and estimate the cost of installing wet cooling towers is discussed in detail in Chapter 5.

6.0 REPORT ORGANIZATION

Following this introduction, this report is organized into the following sections:

- Chapter 2: Discussion of various background elements that are fundamental to understanding the broader implications of retrofitting a once-through cooling system, including the regulatory history of Clean Water Act Section 316(b); previous retrofit analyses; the performance and design of closed-cycle cooling systems, including wet and dry cooling towers; and other IM&E technologies.
- Chapter 3: Discussion of the overall regulatory environment beyond measures that specifically address impacts associated with once-through cooling water withdrawals (the scope of changes that result from adopting wet cooling towers may impact a facility's ability to comply with other regulations, such as air emission standards, modified water discharge limitations, and local use restrictions)
- Chapter 4: Discussion of closed-cycle cooling systems
- Chapter 5: Assumptions and methodology used to develop the conceptual design and cost estimate for a wet cooling tower retrofit at each facility
- Chapter 6: Examples of facilities that have retrofitted or repowered their existing systems
- Chapter 7.A – 7.O: Individual facility analyses
- Appendices

7.0 REFERENCES

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USEPA (U.S. Environmental Protection Agency). 2002. *Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule.* EPA821-R-02-003. U.S. Environmental Protection Agency, Washington, DC.

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2. GENERAL BACKGROUND

1.0 FEDERAL REGULATORY HISTORY

The Federal Water Pollution Control Act Amendments, enacted in 1972 and amended in 1977 (commonly known as the Clean Water Act [CWA]), seek to "restore and maintain the chemical, physical, and biological integrity of the nation's waters" 33 U.S.C. 251(a). Impacts associated with the operation of cooling water intake structures are addressed in CWA Section 316(b), which reads, in its entirety, as follows:

> Any standard established pursuant to section 301 or section 306 of this Act and applicable to a point source shall require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact.

Authority for implementing Section 316(b) resides with EPA and is addressed through the issuance of National Pollutant Discharge Elimination System (NPDES) permits. States may assume this responsibility if they implement an approved permitting program. California received authorization to implement its water quality permitting program in 1989 and currently administers NPDES permits through the actions of the State Water Resources Control Board (SWRCB) and Regional Water Quality Control Boards (RWQCBs) throughout the state. EPA retains the authority to establish the minimum standards that are to be met through the implementation of an NPDES permit, although authorized states may adopt conditions that exceed any federal requirements.

1.1 1977 DRAFT GUIDANCE

In 1976 EPA published a final rule implementing Section 316(b). Following a lawsuit filed by a group of utility companies, the Court of Appeals for the Fourth Circuit remanded the rule citing EPA's failure to comply with the Administrative Procedures Act by not properly publicizing the rule's supporting documentation. EPA later withdrew most of the final rule. During the implementation phase of the 1976 rule, however, EPA published a draft guidance document titled *Draft Guidance Document for Evaluating the Adverse Impact of Cooling Water Intake Structures on the Aquatic Environment.* This document would serve as the basis for implementation of Section 316(b) in subsequent years by regional and state permitting authorities.

The draft guidance outlined an approach for collecting information that would support any determinations made by the permitting authority but did not establish a national technology-based standard for best technology available (BTA), as required by the CWA (USEPA 1977). Following the remand of the 1976 rule, compliance with Section 316(b) varied from state to state and region to region, with many permitting authorities evaluating facility performance based on site-specific criteria. California, through the SWRCB and RWQCBs, continued to implement Section 316(b) on a case-by-case basis in lieu of national standards.

1.2 CONSENT DECREE

In 1993 a group of environmental organizations, led by Hudson Riverkeeper, filed suit against EPA, claiming its failure to establish national technology-based standards violated the CWA. In the plaintiff's view, the case-by-case, site-specific approach that existed following the remand of the 1976 rule created an inconsistent application of the CWA by ignoring the mandate to minimize adverse impacts to a level based on the performance of the best performing technology. In 1995 EPA entered into a consent decree with Riverkeeper and other environmental plaintiffs that established a framework for the development and promulgation of national technology-based standards that would implement Section 316(b).

Subsequent amendments to the consent decree established a phased approach for implementation. Phase I would address new steam electric and manufacturing facilities. Phase II was reserved for large, existing steam electric facilities (those with a design capacity greater than 50 mgd), while Phase III would address all manufacturing facilities with a capacity greater than 2 mgd and steam electric facilities not covered by Phase II.

1.3 PHASE I

EPA issued the Phase I rule in 2001 and implemented a two-track compliance approach for new facilities. Track I restricts the facility's intake flow to a level commensurate with a closed-cycle cooling system and limits the through-screen intake velocity to 0.5 feet per second. Track II allows a facility to demonstrate it can achieve impingement mortality and entrainment reductions comparable to those achieved with closed-cycle cooling by using other technologies, including restoration.

A subsequent lawsuit by environmental and industry petitioners challenged several components of the Phase I rule. The Court of Appeals for the Second Circuit, on February 3, 2004, upheld nearly all the provisions of Phase I with the exception of restoration. The court held that restoration was incompatible with the expressed intent of the statute, which requires "that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." Restoration in this context was deemed an action taken to mitigate the effects of an adverse impact, not one to minimize the impact in the first place. Use of restoration as a compliance option was barred as a compliance alternative under Phase I (*Riverkeeper, Inc. et al. v. U.S. EPA,* 358 F.3d 174 [2d Cir 2004]).

1.4 PHASE II

EPA issued the Phase II rule for large (50 mgd capacity or greater) existing steam electric facilities in 2004. The Phase II rule established performance standards for reductions in impingement mortality (80–95 percent) and entrainment (60–90 percent) over a baseline value. These standards were developed based on the performance of different technologies at existing facilities but are presented as ranges to allow for the biological variability between different locations and other site-specific factors that would make a single numeric limitation difficult to evaluate (USEPA 2004). Facilities with an annual capacity utilization rate under 15 percent, based on a 5-year average, would not be required to meet the rule's entrainment performance standard. An individual unit at a facility that operated below the 15 percent limit would similarly be exempt, provided it did not share an intake structure with other units that together exceeded the threshold.

Phase II required a facility to demonstrate compliance with these standards by choosing one of the following five alternatives:

1. Demonstrate that the facility has reduced cooling water flow to levels commensurate with wet recirculating systems or reduced cooling water intake velocity to 0.5 feet per second or less (for impingement only).

2. Demonstrate that the existing design and construction technologies, operational measures, and/or restoration measures meet the performance standards established by the regulations.

3. Demonstrate that the facility has selected design and construction technologies, operational measures, and/or restoration measures that will, in combination with any existing design and construction technologies, operational measures, and/or restoration measures, meet the performance standards.

4. Demonstrate that the facility has installed and properly operates and maintains an approved technology.

5. Demonstrate that a site-specific determination of best technology available is appropriate through the use of a cost-cost or cost-benefit test.

As in Phase I, industry and environmental petitioners sued EPA over the requirements of the Phase II rule. The Court of Appeals for the Second Circuit, on January 25, 2007, remanded several key components of the rule as either unsupported by EPA's analysis or contradictory to established procedures and the intent of the CWA (Riverkeeper, Inc. et al. v. U.S. Environmental Protection Agency, No. 04-6692-ag[L] [2nd Cir, January 25, 2007]). In response to the Second Circuit's ruling, EPA suspended implementation of the Phase II rule on March 20, 2007, and directed permitting authorities to base permitting conditions for Section 316(b) on best professional judgment (BPJ) (Grumbles 2007).[1] The principal elements of the Second Circuit decision are the following:

1. **BTA Determination.** The court found that EPA had improperly used a cost-benefit methodology to support the final BTA analysis, noting that the cost-benefit approach "compares the costs and benefits of various ends, and chooses the end with the best net benefits." This approach does not comply with the Section 316(b) requirement to develop a technology-based standard and instead relies on a cost-driven analysis that weighs "the desirability of reducing adverse environmental impacts in light of the cost of doing so." Cost

[1] As of the publication of this study, EPA has not formally withdrawn the Phase II rule, noting that future litigation may be possible.

may be used as a consideration in the final BTA determination, but it may not serve as the principal basis for that decision.

The court also found that, when considering cost in relation to BTA assessments, EPA must first determine the best-performing technology and then evaluate whether its cost can be "reasonably borne" by industry, thus making it "available" to the permitted community. In doing so, EPA must consider only the best-performing facilities and not an average performance level across a range of facilities. Only after making this initial assessment can EPA consider other factors, such as whether different technologies can achieve essentially the same results but at a lower cost. This "cost-effectiveness" approach allows EPA, or the permitting authority, to weigh any incremental benefits that may be achieved by one technology over another and determine whether the added cost is justified by the increased benefits. Cost-effectiveness, the court notes, is different from cost-benefit in that it determines "which means will be used to reach a specified level of benefit that has already been established," rather than influencing the initial selection of the standard.

2. **Performance Standards as Ranges**. In Phase II, EPA established performance standards for impingement mortality and entrainment reductions expressed as broad ranges, noting that ranges were necessary to address the variable characteristics that may affect the performance of a technology. A single numeric limitation was considered impractical in light of these differences. The court did not disagree with EPA's use of performance standards as ranges, but noted the omission of any requirement for a facility to maximize its performance under the standard. As written, the Phase II rule could be interpreted to allow a facility to meet the lower end of the performance standards and be considered compliant with the rule's requirements even if a greater degree of performance could be achieved.

3. **Restoration.** The Phase II rule included restoration as a compliance option. EPA argued that the considerations for existing facilities and the more limited technology options available to them were different from the Phase I rule. The court did not agree and rejected EPA's argument, stating the use of restoration was incompatible with the CWA.

All facilities evaluated in this study are considered Phase II facilities, i.e., they have intake capacities greater than 50 mgd, among other qualifying characteristics. EPA, however, has not indicated how it intends to resolve the issues raised in the Second Circuit decision (the court did not remand the rule in its entirety). Future regulatory efforts by EPA may redefine what constitutes a "Phase II" facility.

1.5 PHASE III

EPA issued the Phase III rule on June 1, 2006. Phase III established categorical requirements for new offshore oil and gas extraction facilities with design intake capacities greater than 2 mgd and that withdraw at least 25 percent of the water exclusively for cooling purposes. EPA did not establish uniform national standards for the remaining Phase III facilities (manufacturers and small steam electric facilities). Instead, Phase III continues the implementation of all statutory requirements through the NPDES program on a BPJ basis.

As of the publication of this study, the Phase III rule remains in litigation.

2.0 PREVIOUS RETROFIT ANALYSES

Other studies have developed cost estimates of cooling system retrofits (from once-through to closed-cycle cooling) to try and identify a reasonably certain correlation between plant-specific factors, such as generating capacity, fuel type, and circulating water flow, and the total cost of the new system. A common weakness of these analyses becomes evident when attempting to apply these cost estimates to actual facilities: the numerous site-specific factors that must be evaluated when attempting to retrofit an existing facility greatly influence the final cost and feasibility assessment. Applying unit-based costs such as $/gpm or $/kWh can lead to widely varying estimates that may underestimate or overestimate the true cost. Figure 2–1compares the capital cost estimates developed by other generic studies with this study's individual estimate for California's fossil fuel coastal power plants.[2] These costs only reflect the installation of the cooling towers and all other civil, mechanical, and electrical components; energy penalty, operations and maintenance (O&M), and shutdown losses are not included.

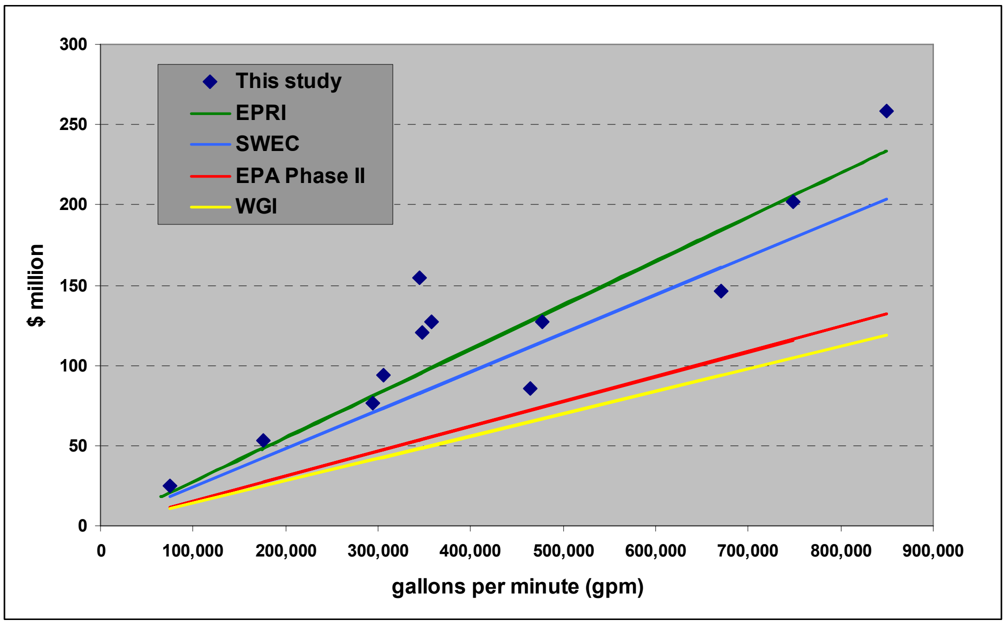

Figure 2–1. Capital Cost Comparison for Fossil Fuel Plants

2.1 STONE AND WEBSTER ENGINEERING CORPORATION

Stone and Webster Engineering Corporation (SWEC) prepared a retrofit cost estimate in a report to the Utility Water Act Group (UWAG)3 in 2002 during the development of the Phase II rule (Yasi 2002). The estimates were based on detailed cost estimates previously conducted for six

[2] All cost values in this chapter have been adjusted to 2007 dollars, except where indicated.

[3] The Utility Water Act Group (UWAG) is an association of 205 electric utilities and four national trade associations of electric utilities: Edison Electric Institute, National Rural Electric Cooperative Association, American Public Power Association, and Nuclear Energy Institute. UWAG frequently represents the interests of the electric power industry in the legislative and regulatory development processes related to the Clean Water Act.

unidentified facilities and extrapolated to the 1,041 units that comprise the Phase II universe. The reference facilities consist of one coal-fired plant located on a freshwater river, while the others (two coal, two nuclear, and one oil) all use marine or brackish waters for cooling. No natural gas facilities were part of the initial data set.

Reference data were compiled into four categories—materials, equipment, labor, and indirect costs—that provided the basis for extrapolated costs. Estimates for all units were then scaled from the reference facility considered to be most similar in terms of size, fuel, and cooling water type, and adjusted for regional differences in labor costs. The circulating water flow rate served as the comparative variable used to correlate costs between the evaluated units and reference data set. Summary data are provided in Table 2–1. The lower cost for Facility 5 is explained by the lower overall effort required to upgrade the existing system in order to accommodate the new closed-cycle cooling system.

Table 2–1. SWEC Reference Facility Costs

Facility	Fuel type	Water body type	Capacity (MW)	Cooling flow (gpm)	Nominal cost ($)	Cost ($/gpm)
1	Coal	Estuary	250	174,627	41,760,000	239
2	Coal	Estuary	620	279,403	66,120,000	237
3	Oil	Estuary	440	259,701	55,680,000	214
4	Nuclear	Marine	863	570,448	140,360,000	246
5	Nuclear	Marine	1,137	895,522	146,160,000	163

2.2 WASHINGTON GROUP INTERNATIONAL

Washington Group International (WGI) developed closed-cycle cooling retrofit estimates for each Phase II unit based on general information regarding the steam cycle and unit size collected from an industry database. Facilities were grouped according to their generating system, steam conditions, and unit size. Other values, such as the thermal load rejected to the condenser and total flow rate, were calculated using heat balance and heat exchange equations and an assumed condenser temperature rise of 12° F. No other site-specific criteria describing the facility were included in the development of the cost estimate.

Cost information was obtained directly from cooling tower vendors for saltwater and freshwater applications with different size and flow specifications. Other elements, such as pumping capacity, additional civil and structural works, and treatment systems, were estimated based on contractor experience and BPJ. The total distance of supply and return piping was estimated based on an assumed maximum distance between the condensers and the cooling towers of 500 feet (for a total of 1,000 feet). WGI included project multipliers to account for indirect and contingent costs such as management, profit, start-up, and engineering. Final costs for the sample facilities in each group were then normalized to a dollar per gpm value and scaled to each unit based on the calculated circulating water flow rate (WGI 2001).

Final costs ranged from $110 to $140 per gpm in saltwater applications.

2.3 EPRI

EPRI developed a closed-cycle cooling retrofit cost estimate during the Phase II rule development in support of public comments submitted by UWAG to EPA. EPRI developed its estimate using cost data obtained directly from facilities and through a literature search of previous studies (EPRI 2002). Information was compiled for 50 representative facilities (unidentified) and categorized by generating capacity, fuel type, and water body type. The cost estimates provided by each facility or obtained from other studies were normalized to account for the level of detail included in each cost estimate and adjusted to current year dollars (2002). Where it could be determined that the provided estimate only included capital costs, EPRI increased the project total value by adding 40 percent of the direct cost to account for "ancillary costs" (engineering, management, and contingencies).

Reference cost estimates were grouped according to the scope of the retrofit and classified as either a "minimum modifications" or "re-optimized" retrofit. The minimum modifications approach leaves most elements of the cooling system unchanged and incorporates a wet cooling tower into the existing system together with other necessary components and upgrades (e.g., pumps, treatment systems, and additional piping).

Re-optimized systems, however, expand the scope of the retrofit primarily by modifying the surface condenser to maintain its design performance with lower flow rates and higher condenser rise temperatures that are part of an optimized cooling tower. This is not always an easy, or inexpensive, undertaking, as EPRI notes:

> [Condenser modification] would be accomplished by changing the tube side from one-pass to two-pass in order to maintain the water velocity in the tubes at an acceptably high level. This in turn requires substantial rearrangement of the inlet and outlet headers and piping and often considerable demolition (and subsequent rebuilding) of the turbine building walls in order to gain access to the condenser for the modifications. (EPRI 2002)

An optimized system will have lower performance penalties and operating costs (fan and pump capacity) but can add significantly to the initial capital cost. EPRI considers the re-optimized approach generally more applicable to baseload facilities with long remaining operational lives over which the increased capital cost can be amortized and notes that there are limited data for this type of re-optimization. Most of the cost data used in its analysis is based on the "minimum modifications" approach.[4]

Cost estimates ranged from $165/gpm to $425/gpm depending on the degree of difficulty associated with the retrofit. Costs reflect a 7 percent increase to account for saltwater applications (EPRI 2007).

2.4 EPA PHASE I AND PHASE II RULES

EPA evaluated the cost of wet cooling tower retrofits in support of the Phase II rule using a model-based approach expanded from the development of costs for new facilities in Phase I

[4] Two of the 50 reference facilities provided data for a re-optimized system, but are not identified in the report.

(USEPA 2001; USEPA 2002). As with other studies, EPA did not assume any major modifications to the condenser except those required to allow the system to function within its design parameters. The new cooling tower would be inserted into the cooling water loop without changing the circulating water flow rate or basic characteristics of the condenser.

New facility costs are developed using a base cooling tower construction cost, in $/gpm, and adjusting upward for various facility and design elements, such as tower material, size, and location. EPA established four base cost estimates depending on the circulating water flow (greater or less than 10,000 gpm) and the design approach temperature (5° F or 10° F). This value was then modified to account for the base tower material (fiber reinforced plastic [FRP], concrete, redwood, Douglas fir) and the type of fill material (splash or film). An installation cost factor accounted for all civil and structural projects as well as management, engineering, profit, and contingencies. Finally, an adjustment was made to account for regional labor and material cost differences. Table 2–2 summarizes the Phase I cost factors that are comparable to the materials evaluated in this study.

Table 2–2. Phase I Cost Factors

Design element	Cost factor
FRP construction	1.1
Splash fill	1.1
Installation	1.8
Regional adjustment (California)	1.081

Beginning with a base capital cost of $35/gpm (capacity greater than 10,000 gpm and 10° F approach temperature) results in a California new facility cooling tower estimate of $82.40/gpm.

In the Phase II rule, EPA developed additional cost factors to address the complexities and logistical obstacles that would be expected when building wet cooling towers at an existing facility. These elements build upon the new facility cost factors and are summarized in Table 2–3.

Table 2–3. Phase II Cost Factors

Design element	Cost factor
Capital cost adjustment	1.25
Retrofit factor	1.2 (low) or 1.3 (high)
Contingency	1.1
Unknowns	1.05

These retrofit cost factors, together with the modified base cost for a new facility, results in an existing facility cost estimate ranging from $143 to $155/gpm, depending on the retrofit factor used.

3.0 IMPINGEMENT MORTALITY AND ENTRAINMENT CONTROLS

Numerous technologies have been developed over the last several decades that attempt to minimize either impingement mortality or entrainment, or both. This section summarizes the basic characteristics of the more widely used technologies, including their advantages and limitations, effectiveness, and general considerations for use at California's coastal facilities. This summary is not an exhaustive review. Instead, it reviews other technology resources to provide context for the larger discussion in this study. The following resources offer a more comprehensive analysis of the different technologies, including performance and cost, and provide examples of onsite evaluations:

> EPA (U.S. Environmental Protection Agency). February 12, 2004. *Technical Development Document for the Final Section 316(b) Phase II Existing Facilities Rule*. EPA 821-R-04-007.
>
> EPRI. 1999. *Fish Protection at Cooling Water Intakes: Status Report.* TR-114013.

The most commonly used technologies discussed in this chapter are generally categorized as follows:

- Physical Barriers: traveling screens; cylindrical wedgewire screens (including fine mesh); nets; aquatic filter barriers
- Collection Systems: modified traveling screens with fish returns
- Behavioral Barriers: velocity caps
- Flow Reduction: closed-cycle cooling; variable speed pumps
- Operational Modifications: intake relocation; seasonal operation

While many of these methods have been employed successfully and can achieve the level of impact reduction contained in the California Ocean Protection Council (OPC) resolution, actual reductions vary from site to site depending on many factors. The key to maximizing a technology's potential effectiveness lies in the evaluation of the mix of physical *and* biological characteristics that are unique to each location, and subsequently optimizing its design and installation with respect to those parameters. Ongoing monitoring and system modifications are often necessary to ensure that the desired reduction is achieved consistently following installation.

This study, therefore, limited detailed evaluation to technologies whose impact reductions can be reasonably assumed when certain physical and logistical requirements are met. In addition, greater emphasis is placed on the ability of a technology to reduce entrainment impacts rather than impingement. While impingement mortality remains a concern at most, if not all, of California's coastal facilities, entrainment impacts are common to all facilities and are thought to have a greater adverse impact on aquatic habitats, especially those located in more productive waters.

Most technology options that reduce entrainment can often be configured to reduce impingement mortality as well. Fine-mesh traveling screens, for example, are typically designed with the same collection and return system that also serves as an impingement mortality control.[5] Likewise, aquatic filtration barriers (AFBs) will reduce both impingement and entrainment if they can be maintained properly. The same cannot be said for many impingement controls, such as barrier nets, velocity caps, or behavioral barriers, which cannot be configured to reduce entrainment.

Many facilities with once-through cooling systems employ some type of primary screening device to prevent larger debris from being drawn into the facility cooling system and damaging sensitive equipment. Vertical traveling screens are the most common screening technology used at California's coastal facilities. Traveling screens, as their name implies, consist of mesh panels fixed on a continuous loop that rotate through the water column and remove large objects from the intake forebay. Most often configured in a vertical orientation with slot sizes ranging from 3/8 inch to 1/2 inch, traveling screens typically rotate on a predetermined time cycle or based on a maximum pressure differential between the upstream and downstream faces of the screen panels. High-pressure sprays are used to remove debris from the screen, which is then disposed of in a landfill or returned to the source water. These screening systems are not designed to distinguish between debris and impinged fish and, due to their large slot sizes, do not offer any protection against entrainment.

3.1 BARRIER NETS

Fish barrier nets are constructed of wide-mesh fabric panels and configured to completely encircle the cooling water intake structure inlet from the bottom of the water column to the surface. The relatively large slot sizes (1/2 inch) combined with the larger overall area of the net reduce impingement mortality by preventing physical contact with the main intake structure and by maintaining a low through-net velocity (typically 0.2 feet per second [fps] or less), which prevents organisms from being drawn against the net. Fish barrier nets have been deployed most successfully in locations where seasonal migrations create high impingement events, and their use can be limited to these same periods. Seasonal use avoids damage that may be caused by winter icing or high waves. Impingement mortality reductions have exceeded 90 percent at some locations (USEPA 2004).

Barrier nets are not considered for further evaluation in this study because their use at most California facilities is infeasible and they offer no protection against entrainment impacts. Most of the intake structures in this study are located either directly on the Pacific Ocean at shoreline or submerged a considerable distance offshore. To date, there are no facilities that have deployed a barrier net in a submerged configuration or for a shoreline intake located directly on the ocean. The conditions that would be expected at these locations, particularly during winter storms, present significant challenges to the deployment of a barrier net, especially one that would be required year round. At other facilities, where intakes are located within harbors or estuaries, the large overall size of a barrier net will likely conflict with other uses of the water body, such as shipping, boating, swimming, or recreational and commercial fishing.

[5] This is by no means a guaranteed result. A 1985 test evaluation of fine-mesh screens at Brayton Point Station in Massachusetts produced measurable entrainment reductions but significantly increased the impingement mortality of bay anchovy (LMS 1987).

3.2 AQUATIC FILTRATION BARRIERS

Aquatic filtration barriers (AFBs) are fabric panels constructed of small-pore (< 20 microns) materials and deployed in front of an intake structure much like a barrier net. The small openings in the fabric allow water to pass through while screening out most organisms, including those that are susceptible to entrainment. The small openings reduce the through-fabric flow rate to a maximum of 10 gpm per ft^2, as opposed to 25–27 gpm per ft^2 for barrier nets. At a given facility, an AFB will be approximately 2.5 times larger than a barrier net and require a larger open area for placement. The smaller openings are also more susceptible to fouling and clogging by sediment or debris and require a more active maintenance effort to minimize performance losses. An AFB deployed in marine or brackish waters, where clogging and fouling is more of a concern than in a freshwater environment, would likely operate below its design maximum and further increase the initial size of the system required to reliably provide sufficient water to the facility.

To date there has been only one deployment of an AFB at a facility with a large intake volume comparable with the facilities in this study.[6] The Lovett Generating Station, located on the Hudson River in New York, with an intake capacity of 391 mgd, has conducted a comparative evaluation of a seasonally-deployed AFB between one protected and one unprotected intake in different configurations since 1995. Impingement reductions have been substantial, with observed reductions of 90 percent or better. Entrainment has consistently been reduced by 80 percent, compared to the unprotected intake that serves as the baseline (LMS 2000). Wave overtopping and screen fouling present the greatest challenges to maintaining the system at its optimal level of performance.

AFBs are not considered for further evaluation in this study due to the lack of data for deployments at large facilities and the significant logistical challenges that must be overcome to ensure successful installation. If local conditions can be met, AFBs would be expected to reduce impingement and entrainment to levels comparable with reductions observed at Lovett. As with barrier nets, however, there have been no evaluations of AFBs under conditions that approximate those encountered along the Pacific coast. With their greater overall size and higher susceptibility to performance degradation from fouling or clogging, AFBs are more limited in their potential deployment than barrier nets.[7]

3.3 FINE-MESH CYLINDRICAL WEDGEWIRE SCREENS

Fine-mesh cylindrical wedgewire screens reduce impingement by maintaining a low through-screen velocity (0.5 fps), which allows larger organisms to escape the intake current. Entrainment is reduced through the use of screen mesh with slot sizes small enough to prevent eggs and larvae from passing through.[8] The phenomenon of hydrodynamics resulting from the cylindrical shape of the screen aids in the removal of small "entrainable" organisms that become caught against the screen. The low through-screen velocity is quickly dissipated and allows organisms to escape the

[6] An AFB evaluation was proposed for Contra Costa Power Plant but halted due to maintenance difficulties (CEC 2005).
[7] In its Proposal for Information Collection, El Segundo Generating Station proposed a pilot study of a submerged AFB configuration. The current status of this project is unknown (El Segundo 2005).
[8] Screens with slot sizes ranging from 1 to 2 mm are generally considered to be "fine mesh," although the effective size in each installation must be determined based on the target species in the affected water body.

influence of the system, provided there is a sufficient ambient current present to carry freed objects away from the screen (Weisberg et al. 1984). Organisms that are impinged against the screens are released through the action of a periodic airburst cleaning system and carried away by the ambient current.

Alden Research Laboratories, in coordination with EPRI, conducted laboratory evaluations of the effectiveness of fine-mesh cylindrical wedgewire screens using screens with different slot sizes and through-screen velocities. Reductions approached 100 percent for impingement and 90 percent for entrainment, depending on the specific design conditions (Amaral et al. 2003). These reductions compare favorably to results from facilities that have deployed or tested fine-mesh cylindrical wedgewire screens for entrainment reductions (Seminole: 99 percent; Logan: 90 percent) (EPRI 1999). Using these results and other data, EPA determined that fine-mesh cylindrical wedgewire screens used at certain freshwater river facilities with sufficient ambient current and a through-screen velocity of 0.5 fps or less could meet BTA requirements under Section 316(b). This determination was not extended to facilities in other water body types, such as estuaries and oceans, due to the lack of available information about such deployments, although their use may be determined on a case-by-case basis.

Despite the expanding use of fine-mesh cylindrical wedgewire screens in marine and brackish waters, current data remains insufficient to determine their effectiveness with reasonable certainty at many of California's facilities, most of which are situated on the Pacific Ocean and would require placement offshore along the seabed. Existing applications are located in water bodies with known ambient currents that are unidirectional and allow the screens to be oriented in line with the current, which aids in fish avoidance and removal of small organisms and debris from the screens. The near-shore currents found at coastal facilities are less easily predicted and can slacken or change direction along with the tide, potentially impacting the ability of the screens to remain free of debris and impinged organisms. Without a consistent current, screens may quickly clog and impact the performance of the facility. The distance from shore that would be required (2,000 feet or more) further complicates the use of wedgewire screens because the ability to maintain sufficient air pressure for the airburst cleaning system decreases substantially at those distances, and they cannot be assured to function at all times (Someah 2007).

This study evaluates fine-mesh cylindrical wedgewire screens for Pittsburg and Contra Costa, both of which are located on the Sacramento/San Joaquin Delta, where sufficient ambient currents are more likely to be present. The actual deployment of this technology would require more careful consideration of the various species (and their life stages) that would be protected by the screens.

A portion of the cost estimate developed for these facilities is based on the methodology prepared by EPA for the Phase II rule and scaled to 2007 dollars. Initial capital costs have been revised with updated estimates from cylindrical wedgewire screen vendors. The reason for this update is largely due to the increases in the cost of materials used in construction that have outpaced inflation, particularly for the preferred material for saltwater and brackish environments: 316-stainless steel. Costs are developed from vendor estimates for fine-mesh screens (1.4-mm slot size) based on the total flow required for each facility. At this mesh size, the initial capital cost of the screens ranges from $6.30 to $7.40/gpm depending on the overall length of each screen and the total number of screens required (GLV 2007). This cost includes the airburst system (except piping to the screens) and installation but does not allow for any changes or additions to the circulating water pipes or pump capacity that may be needed. These additional elements, if necessary, and the increased O&M costs, are scaled from the Phase II estimates (USEPA 2004) and other data used in the development of this report.

3.4 MODIFIED TRAVELING SCREENS (RISTROPH SCREENS)

Vertical traveling screens, such as those at most of California's facilities, can be modified to capture and remove fish that are impinged against the screens and return them to the source water body without inducing serious injury or mortality. The term "Ristroph screens" refers to a particular modification where individual screen panels are fitted with water-filled buckets that collect fish temporarily. As the screens rotate, the buckets empty into a return trough or pipeline that is flushed with water to carry the captured fish back to the source. A low-pressure spray is employed to gently remove any organisms that remain impinged on the screens and send them to the return trough, followed by a high-pressure spray to remove other debris. The critical design elements of this system include the screens' rotation speed, the material and shape of the collection buckets, and the method of return to the water body. Ristroph screens designed to reduce impingement mortality are relatively easy to install and do not involve substantial modification to the existing intake structure. The principal new component is usually the fish return system.

Modified traveling screens have been shown to reduce impingement by up to 90 percent or more (USEPA 2004; EPRI 1999). Common to most of these applications is the need to tailor the final design and operation of the system to the unique mix of species and hydrodynamic conditions at each facility. Factors ranging from the screen and collection bucket material to the speed at which the screens are rotated can directly affect the overall effectiveness, which may vary from species to species. Hardier species may exhibit higher latent survival rates than smaller, more fragile species.

These systems can be fitted with fine-mesh panels to reduce the entrainment of eggs and larvae as well. Screen slot sizes typically need to be within the range of 1–2 mm in order to be effective as an entrainment reduction measure, although the size used at a particular location is dependent on the target species. With a smaller open area per square foot than standard screens, fine-mesh screens require a larger overall intake structure in order to maintain desirable intake velocities. The need to expand the intake structure to accommodate the new screens may result in a temporary shutdown.

Entrainment reductions can also range as high as 90 percent or more when fine-mesh panels are used in conjunction with a return system. What is less understood, however, is the viability of eggs and larvae following their impingement against a fine-mesh screen and their return to the water body. Few studies have been conducted that evaluate viability, primarily because of the smaller number of facilities that have adopted fine-mesh traveling screens.[9] Screened organisms,

[9] Big Bend Power Plant in Tampa Bay conducted a viability analysis that showed that latent survival rates for eggs and larvae impinged against the fine-mesh screen and returned to the water were comparable to the control sample (EPRI 1999).

although they have been prevented from being entrained through a cooling water system, may suffer serious injury or mortality, which effectively results in the same adverse impact.[10]

It is unclear how this uncertainty can be reconciled with the OPC resolution's benchmark of reducing entrainment *impacts* rather than simply reducing the number of organisms that are entrained in the first place. For this reason, and the site-specific nature of their performance, fine-mesh traveling screens are not evaluated further in this study.

3.5 VELOCITY CAPS

Offshore intakes may be fitted with a device know as a velocity cap, which is a physical barrier placed over the top of an intake pipe rising vertically from the sea floor. Water is drawn into the pipe through openings placed on the sides of the cap, which converts what had been a vertical current to a horizontal one. Motile fishes are less likely to react to dramatic changes in vertical currents, but exhibit a more consistent flight response when the changes are sensed in the horizontal current, thus preventing their capture by the intake system (ASCE 1982). Velocity caps are classified as an impingement reduction technology because they function by discouraging "impingeable" fishes from entering the system. Velocity caps offer no reduction in the rate of entrainment.

Ormond Beach, Scattergood, El Segundo, Redondo Beach, Huntington Beach, and San Onofre currently employ offshore intakes with velocity caps for their cooling systems. While the impingement reductions can be substantial, performance may vary unexpectedly. Studies at Huntington Beach and El Segundo have shown impingement reductions ranging as high as 90 percent (Musalli et al. 1980). San Onofre operates two separate intake structures that are essentially mirror images of each other. The intakes for Units 2 and 3 are located offshore with velocity caps in relative proximity to one another at similar depths and bathymetry. Impingement data for 2003, however, showed more than 2.5 million fish impinged at Unit 3, a rate nearly 2.5 times that for Unit 2 (SCE 2005).[11]

Velocity caps are not considered for further evaluation in this study due to their inability to address entrainment and the need for site-specific biological information. All of California's facilities that currently operate submerged offshore intakes already use velocity caps. Modification of the remaining facilities would also involve the relocation of the intake to deeper waters.

3.6 CLOSED-CYCLE COOLING

Options and considerations for closed-cycle cooling are discussed in more detail in Chapter 4.

[10] The Phase II performance standards expressly require an entrainment *reduction* rather than an entrainment *impact reduction*.

[11] The intake structure at San Onofre also incorporates guiding vanes and a fish elevator to capture and return any fish that have been drawn past the velocity cap. The citation summarizing the disparity in impingement rates does not offer any information describing the role played by the velocity cap or return system. The species abundance was relatively similar for each intake (SCE 2005).

3.7 VARIABLE FREQUENCY DRIVES

A variable frequency drive (VFD) (similar to variable speed pumps [VSPs]) allows a facility to lower the cooling water withdrawal rate by reducing the electrical load to the pump motor. The pump speed can be tailored to suit the cooling water demands at a certain time or under certain conditions. VFDs can throttle a pump's flow rate more precisely according to operating conditions, but must operate at a minimum flow rate in order to maintain sufficient head and prevent damage to the pump from cavitation. Depending on the initial design specifications, VFDs can achieve flow reductions ranging from 20 to 50 percent of their maximum capacity (Treddinick 2006).

Actual flow reductions with a VFD vary throughout the year depending on seasonal conditions and facility operations. At their maximum efficiency, VFDs enable a facility to withdraw the same volume of water as conventional circulating water pumps, thereby negating any potential benefit. Baseload units would not be ideal candidates for this technology, since they operate in the upper range of their load capacity for significant portions of the year. Units that are designated for peak or intermittent dispatch are more likely to accrue benefits from this method of flow reduction. In these situations, the use of VFDs must be evaluated against the operational profile of that facility and any seasonal variations in the makeup or abundance of affected species in the water body.

A facility that employs VFDs may be able to reduce its intake flow by 40 percent on an annual basis, but may operate at its maximum capacity during the most critical periods of the year, i.e., during spawning or migration seasons. An annual flow reduction might be a suitable metric if the potential for impact is equally distributed throughout the year. This method skews the actual benefit, however, if 80 percent of the potential annual impact occurs within a short time period that also corresponds to maximum pump operation.

At Contra Costa Power Plant, for example, VFDs are installed on the circulating water pumps for Units 6 and 7. From May 1 to July 15, which overlaps with periods of striped bass larval abundance, operating procedures call for the VFDs to operate at 50 percent capacity until the unit is generating a 172 MW load. Above that threshold, the pumps gradually increase the intake flow until they reach 95 percent of the maximum capacity. Depending on the amount of time in operation and the corresponding generating load, VFDs may reduce intake volumes by as little as 5 percent (Mirant Delta 2006).

The inability to determine seasonal variations in the potential use of VFDs excludes them from further consideration in this study.

3.8 INTAKE RELOCATION

Cooling water intakes that are located at an ocean shoreline or within an estuary are thought to have a greater environmental impact due to their presence in more biologically productive areas. Deep offshore locations may avoid or reduce some of these impacts by nature of their location in less sensitive areas. EPA recognized this distinction in the Phase II rule when it defined a baseline facility as one located flush with the shoreline at the surface, but acknowledged the limited data available that support this claim and the need to evaluate each installation on a case-by-case basis (USEPA 2004).

Six of the facilities in this study already utilize a deep offshore intake in conjunction with a velocity cap. Despite the location of these intakes in "less productive" waters, there has been no formal acceptance of their comparative benefit versus intakes located onshore or in estuaries, if any, by the NPDES permitting authorities for these facilities. Various state agencies have also demurred on a consensus opinion regarding the relative effectiveness of offshore intake locations (CCC 2000; SLC 2006; CEC 2005; SWRCB 2006). This study, therefore, does not evaluate intake relocation as a control technology because it must be viewed in conjunction with a site-specific biological assessment.

3.9 SEASONAL OPERATION

Seasonal operation may allow for significant reductions of impingement and entrainment at non-baseload facilities, provided the operational period does not overlap with times of highest impingement and/or entrainment susceptibility in the affected water body. The limitations associated with seasonal operation are similar to the issues concerning the use of VFDs, discussed in Section 3.7.

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3. Regulatory Review

1.0 General Regulatory Considerations for Cooling System Retrofits

The conversion of an existing power plant's cooling system from once-through to a wet cooling tower would involve considerations and reviews across a range of regulatory programs. The following discussion provides an overview of the programs and agencies that would be involved and highlights the specific aspects that would need to be addressed as part of a conversion. The review focuses on environmental and planning programs at the federal, state, and local government levels, including executive orders, statutes, regulations, and policies. In some cases, the objectives of different programs and policies may conflict with one another.

The lead agency for permitting each power plant conversion project cannot be projected for this study and is likely to vary on a site-by-site basis. The Regional Water Quality Control Boards (RWQCBs), Air Pollution Control Districts (APCDs)/Air Quality Management Districts (AQMDs), California Energy Commission (CEC), California Coastal Commission (CCC), Bay Conservation and Development Commission (BCDC), and State Lands Commission (SLC) all will likely play significant roles, and may serve in a lead role for a specific facility.

The Nuclear Regulatory Commission (NRC) will also play an important role in overseeing any retrofit projects undertaken at Diablo Canyon Power Plant and San Onofre Nuclear Generating Station to ensure any proposed redesign complies with all applicable operating and safety requirements.

2.0 Agency Roles and Responsibilities

A number of state and local agencies would be involved in the review and permitting of a cooling system retrofit at existing power plants. In addition federal agencies may become involved where federal issues, such as endangered aquatic species, nuclear safety, navigable/harbor waters, military zones, etc., are present at the intake structure site. The roles of these agencies are summarized below and further described in sections 3.0-7.0.

2.1 State Lands Commission

The SLC has jurisdiction and control over public trust lands, which can generally be described as all ungranted tidelands and submerged lands and beds of navigable rivers, streams, lakes, bays, estuaries, inlets, and straits in the state. These lands include a wide section of tidal and submerged land adjacent to the state's coast and offshore islands, including bays, estuaries, and lagoons, and are managed by the SLC under a multiple-use policy for water-related commerce, navigation, fisheries, recreation, open space, and other recognized public trust uses.

In its administration of surface leases on public trust lands, the SLC considers numerous factors in determining whether a proposed use is appropriate, including the protection of natural resources and other environmental values as well as preservation or enhancement of the public's access to state lands. Where a lease is issued, the SLC can serve as the lead agency for California Environmental Quality Act (CEQA) analyses. The SLC also comments on Environmental Impact Reports (EIRs) for land use changes within its jurisdiction and on projects that affect state lands. The SLC also conducts a review of applications submitted to the CCC.

2.2 CALIFORNIA ENERGY COMMISSION

The Warren-Alquist Act grants the CEC the exclusive authority to license new power plants with capacity greater than 50 MW or repower projects that increase the facility capacity by 50 MW or more. As part of this process, the CEC is required to make findings regarding the project's conformance with applicable laws, ordinances, regulations, and standards (LORS). The CEC also serves as the lead agency for CEQA compliance. The Warren-Alquist Act includes specific provisions for compliance with the California Coastal Act, including specific CEC requirements for coordination with the CCC.

If an existing power plant was originally licensed by the CEC, a modification to the cooling system would require an amendment to the original decision, including an assessment of compliance with CEQA. If the facility was not originally licensed by the CEC, a modification to only the cooling system would not require CEC permitting or approval.

2.3 NUCLEAR REGULATORY COMMISSION

A nuclear facility's design is understandably more complex than a typical fossil-fueled facility and incorporates additional systems that require cooling in addition to the main condenser. Auxiliary and safety systems, such as component cooling, spent fuel storage, and emergency cooling, may operate in parallel with the main condenser system with dedicated pumps and supply lines. These systems may also be integrated as part of facility-wide cooling system. In either case, special consideration must be given to ensure these systems could continue to operate as intended following conversion to wet cooling towers.

The Energy Reorganization Act of 1974 established the NRC and tasked the agency with the oversight of commercial nuclear operations, material and waste management, and decommissioning activities. Accordingly, the NRC exercises broad regulatory authority over commercial nuclear power plants to protect public health and safety and maintains rigorous design criteria to meet these goals. Any major modification proposed for an existing facility would be subject to NRC review and approval to ensure compliance with all applicable regulations and standards.

2.4 OCEAN PROTECTION COUNCIL

The OPC is responsible for coordinating the activities of ocean-related state agencies and improving ocean protection. The objectives of the OPC are more narrowly defined than many other agencies. With respect to conversion to once-through cooling, the OPC may have a coordination role but does not have specific permitting or approval authority for individual facilities.

2.5 REGIONAL WATER QUALITY CONTROL BOARDS

California has nine RWQCBs that are responsible for implementing the requirements of the Porter-Cologne Water Quality Control Act and the Clean Water Act (CWA), including CWA Section 316(b), which governs cooling water intake structures. Each RWQCB implements the requirements of the CWA and Porter-Cologne through the issuance of National Pollutant Discharge Elimination System (NPDES) permits, which include standards set forth in each RWQCB's Basin Plan as well as State Water Quality Control plans such as the Thermal Plan, Ocean Plan, and California Toxics Rule (CTR). NPDES permits issued to power plants address the operation of cooling water intake structures that withdraw water from surface waters of the state as well as the direct discharge of cooling water and other wastewaters. Since conversion of a once-through cooling system to a wet closed-cycle system would require a major modification to the facility's NPDES permit, the RWQCBs will have a primary role in permitting power plant conversions.

2.6 CALIFORNIA COASTAL COMMISSION

The Coastal Act of 1976 permanently established the CCC, which, in partnership with local county and municipal planning authorities, plans and regulates development in the coastal zone. Development within the coastal zone can proceed only subsequent to issuance of a coastal development permit issued by an approved local coastal program or, in limited circumstances, by the CCC itself. Where the CCC issues a permit, the commission or the local coastal planning agency must comply with CEQA and may serve as the lead agency for a CEQA analysis.

An exception to the CCC's permitting authority is provided under the Warren-Alquist Act for new power plants or those projects involving an increase of 50 MW or more. In these cases, the CCC participates in the CEC's review process but does not have independent permitting authority. The CCC's role (under Section 30413[d] of the Coastal Act) is to provide to the CEC a report describing what measures are necessary for the proposed project to conform to Coastal Act policies. The CEC must then adopt those measures as part of any approval, unless it finds that the measures are infeasible or would cause greater adverse environmental harm.

2.7 BAY CONSERVATION AND DEVELOPMENT COMMISSION

San Francisco Bay is excluded from the California Coastal Act and instead is addressed by the McAteer-Petris Act. Under this act, the BCDC functions similarly to the Coastal Commission in the Bay Area. Only two power plants addressed by this study (Pittsburg and Contra Costa) are under BCDC jurisdiction.[1]

[1] Potrero Power Plant was not included in this study.

2.8 REGIONAL AIR POLLUTION CONTROL DISTRICTS/AIR QUALITY MANAGEMENT DISTRICTS

In California, authority to enforce the requirements of the Clean Air Act (CAA) and its implementing regulations, as well as state and local air pollution laws and regulations, rests with 35 regional air pollution authorities known as the APCDs/AQMDs. These are established by county or by larger regional area. APCDs/AQMDs issue all permits and approvals required by the CAA. The State Air Resources Board develops statewide standards, while the APCDs/AQMDs establish individual airshed plans.

3.0 ENERGY AND ONCE-THROUGH COOLING POLICIES

3.1 CALIFORNIA ENERGY ACTION PLAN

Reacting to a statewide energy crisis manifested in high energy costs and rolling blackouts, the state approved an Energy Action Plan (EAP) in 2003. The EAP, created by California's three principal energy agencies (the CEC, the California Public Utilities Commission (CPUC), and the Consumer Power and Conservation Financing Authority, which is now defunct), identifies specific goals and actions to eliminate energy outages and excessive price spikes in electricity and natural gas. The EAP, which is a living document and was supplemented by the Energy Action Plan II in 2005, "will be ever mindful of the need to keep energy rates affordable, and is sensitive to the implications of energy policy on global climate change and the environment generally."

The EAP envisions a "loading order of energy resources" to guide decisions made by the three regulating agencies, jointly and singly. The loading order is a priority sequence for agency actions addressing the state's energy needs, described as follows:

- Optimize all strategies for increasing conservation and energy efficiency to minimize increases in electricity and natural gas demand.
- Encourage that new generation needs are first met by renewable energy resources and distributed generation.
- Support additional clean fossil fuel, central-station generation until the preferred resources have had sufficient investment and adequate time to "get to scale."
- Provide the bulk electricity transmission grid and distribution facility infrastructure to support growing demand centers and the interconnection of new power generation.

The CPUC's approach to the loading order prioritizes energy resources on the demand side to emphasize energy conservation, resource efficiency, and reduction of per capita demand; and on the supply side, favors renewables over fossil fuel resources. The Energy Action Plan II specifically includes climate change as an action area, acknowledging a strong connection between energy use and climate change. Regarding climate change, the plan identifies several key action steps for the state's energy agencies, including implementation of strategies to meet the greenhouse gas emission reduction goals established by Executive Order S-3-05 (discussed below). More broadly, throughout the EAP and Energy Action Plan II, there is emphasis on developing environmentally sound energy sources. In addition, under Research, Development, and Demonstration, Action Item 8 encourages the development of cost-effective dry cooling technologies and reduction of once-through cooling practices to minimize the impact of new generation on California's water resources.

Converting power plants to wet cooling tower systems would generally be consistent with the goal of reducing environmental impacts. At the same time, the minor loss of generating efficiency associated with conversion could be construed as conflicting with some of the plan goals, although the primary focus is on retiring older plants and replacing them with cleaner, more efficient energy sources. Overall, on a plant-by-plant basis, the implementing agencies will have to consider the plan goals in evaluating conversion scenarios.

3.2 CALIFORNIA OCEAN PROTECTION COUNCIL RESOLUTION ON THE USE OF ONCE-THROUGH COOLING TECHNOLOGIES IN COASTAL WATERS

The OPC passed a resolution on April 20, 2006, that effectively discourages the use of once-through seawater cooling. The OPC has resolved to accomplish the following:

- Urge the State Water Board to implement CWA Section 316(b) and any more stringent state requirements that require reductions in entrainment and impingement at existing coastal power plants, and encourage the state to implement protective controls to achieve a 90–95 percent reduction in such impacts.
- Encourage the State Water Resources Control Board (SWRCB) to form a group to provide technical review of each coastal power plant's data collection proposals, analyses, and impact reductions; and implement statewide data collection standards to comply with CWA Section 316(b) requirements.
- Establish an interagency committee from the RWQCBs, the CEC, the CPUC, the CCC, and others to integrate agency actions and to coordinate regulatory authorities.
- Fund a six-month study to analyze each existing coastal power plant's conversion to alternative cooling technologies or installation of best technology available.
- Work with the RWQCBs, the CEC, the CPUC, the CCC, and others to investigate non-regulatory incentives to accelerate conversion from once-through cooling.

The resolution highlights OPC's desire to encourage interagency cooperation to facilitate the implementation of protective controls that can address the impacts associated with once-through cooling water withdrawals. Specifically targeting the protection of marine resources, the resolution does not explicitly take operational efficiencies into account. The resolution's call for an interagency workgroup that includes the CEC and CPUC may enable the various entities to reconcile any inconsistencies between the OPC's objectives and those established under the EAP. The impact of the resolution on the retrofitting process will be determined by the subsequent work by the interagency workgroup and actions taken by the SWRCB and RWQCBs.

As adopted, the OPC resolution did not explicitly call for a technology cost evaluation as part of this study. Interagency and staff discussions following its adoption, however, identified the need to develop cost assessments as part a technology's overall feasibility evaluation at each coastal power plant. The OPC believes that collecting cost data in conjunction with the engineering assessments is an appropriate step in assisting other state agencies in the regulatory process.

While this study contains initial cost data in addition to providing long-term cost estimates, no conclusions are reached with respect to a particular retrofit option's *economic* feasibility.

3.3 CALIFORNIA COASTAL ACT

On land, the coastal zone varies in width from several hundred feet in highly urbanized areas up to five miles in rural areas; and it extends three miles offshore. The coastal zone established by the Coastal Act excludes San Francisco Bay, where development is regulated under the McAteer-Petris Act. The Coastal Act includes specific policies regarding such subjects as public access to the shore, protection of terrestrial and marine habitat, visual resources, land form alteration, and agricultural lands. These policies are the standards that are applied to the planning decisions affecting the coastal zone made by local authorities and the CCC.

The CCC is the designated coastal management agency for the purpose of administering the federal Coastal Zone Management Act, which grants to those agencies, when coastal resources are affected, regulatory control over all federal activities and federally licensed, permitted, or assisted activities. Such activities may include outer shelf oil and gas leasing, exploration, and development; military projects at coastal locations; and issuance of Corps of Engineers dredge and fill (CWA Section 404) permits.

Implementation of the California Coastal Act is carried out through a partnership between the CCC and local planning authorities that includes approximately 15 counties and 60 municipalities. These entities prepare local coastal programs (LCPs), which include land use plans (zoning maps, zoning ordinances, and other legal instruments) that are consistent with the policies established by the act and approved by the CCC. Development within the coastal zone can then proceed only subsequent to issuance of a coastal development permit by local planning authority and/or, for any submerged portion of a project, by the CCC itself under its retained jurisdiction. Projects that are larger than 50 MWe are subject to the exclusive siting authority of the CEC.

The Coastal Act includes the following statements of policy regarding development within the coastal zone. These policies could affect the conversion of a power plant from once-through cooling to a wet closed-cycle cooling system.

- Regarding electrical generating facilities the Coastal Act specifically states, "Notwithstanding the fact electrical generating facilities … may have significant adverse effects on coastal resources or coastal access, it may be necessary to locate such developments in the coastal zone in order to ensure that inland as well as coastal resources are preserved and that orderly economic development proceeds within the State."
- Development in the coastal zone shall not interfere with the public's right of access to the sea.
- Coastal areas that are well suited for water-oriented recreational activities that cannot be readily provided at inland water areas shall be protected for such uses.
- Upland areas necessary to support coastal recreational uses shall be reserved for such uses, where feasible.

- Marine resources shall be maintained, enhanced, and, where feasible, restored. Uses of the marine environment shall be carried out in a manner that will sustain the biological productivity of coastal waters.
- Development in areas adjacent to environmentally sensitive habitat areas, parks, and recreation areas shall be sited and designed to prevent impacts that would significantly degrade those areas, and shall be compatible with the continuance of those habitat and recreation areas.
- California Code of Regulations (CCR) Section 30250 establishes policy that new residential, commercial, and industrial development shall be located within, contiguous with, or in close proximity to existing developed areas able to accommodate it or, where such areas are not able to accommodate it, in other areas with adequate public services and where it will not have significant adverse effects on, either individually or cumulatively, coastal resources.
- The scenic and visual qualities of coastal areas shall be considered and protected as a resource of public importance. Permitted development shall be sited and designed to protect views and, along the ocean and scenic coastal areas, to minimize the alteration of natural land forms, to be visually compatible with the character of surrounding areas, and, where feasible, to restore and enhance visual quality in visually degraded areas.
- Industrial facilities shall be encouraged to locate or expand within existing sites and shall be permitted reasonable long-term growth, consistent with the policies of the Coastal Act. Where new or expanded coastal-dependent industrial facilities cannot feasibly be accommodated in a manner consistent with the polices of the Coastal Act, such facilities may still be permitted if (1) alternative locations are infeasible or more environmentally damaging; (2) to do otherwise would adversely affect the public welfare; and (3) adverse environmental effects are mitigated to the maximum extent feasible.

The conversion of power plants to closed-cycle cooling is clearly consistent with some of the policies of the Coastal Act (e.g., conserving, enhancing, and restoring marine resources) but may be inconsistent with others (e.g., related to visibility, land use, and public access). The effects of the conversion and overall consistency with the act must be determined on a site-by-site basis, including mitigation measures to address specific act requirements.

4.0 WATER QUALITY

4.1 PORTER-COLOGNE WATER QUALITY ACT

The Porter-Cologne Water Quality Act (California Water Code [CWC] Section 13000 et seq.) provides for the preservation, enhancement, and restoration of the state's water quality. Specifically, CWC Section 13142.5 establishes state policy that wastewater discharges be treated to protect present and future beneficial uses and, where feasible, to restore past beneficial uses. Highest priority is given to improving or eliminating discharges that adversely affect the following:

- Wetlands, estuaries, and other biologically sensitive sites
- Areas important for water contact sports
- Areas that produce shellfish for human consumption
- Ocean areas subject to massive waste discharges

In determining the effects of such discharges, the policy requires consideration of ocean chemistry and mixing processes, marine life conditions, other present or proposed outfalls in the vicinity, and relevant aspects of area wide waste treatment management plans and programs, *but not* convenience to the discharger. The policy suggests that wastewater containing "toxic and hard-to-treat substances" should be discharged to a sanitary sewer system or pretreated before being discharged to a sanitary sewer system.

CWC Section 13142.5 also expresses policy regarding (1) facility siting, design, and treatment technology, and mitigation measures, when seawater is used for cooling; (2) new thermal discharges to coastal wetlands and areas of special biological significance (ASBSs); (3) baseline marine studies, when new or expanded facilities use seawater for cooling; and (4) preference for use of recycled water, when it is feasible. When new or expanded coastal power plants use seawater for cooling, "the best available site, design, technology, and mitigation measures feasible shall be used to minimize the intake and mortality of all forms of marine life."

CWC Section 13142.5 applies to power plants that use once-through cooling or wet cooling towers, since in each case, plants would require intake and discharge facilities. A plant using seawater as makeup water in wet cooling towers would need to meet the same provisions, including the use of the best available site, design, technology, and mitigation measures on the intake, although the volume of water passing through the system would be reduced significantly from a once-through system.

Other sections of the CWC are also relevant to cooling system conversions. Section 13240 requires RWQCBs to develop and implement Regional Water Quality Control Plans (Basin Plans), which establish water quality criteria for all state waters in their region. Section 170.2 requires the development of the Ocean Plan by the SWRCB, which establishes procedures for the use and protection of ocean waters.

4.2 CLEAN WATER ACT

4.2.1 SECTION 316(B)

This section is discussed in the Chapter 3 of this report.

4.2.2 SECTION 402

Discharges to surface water from power plants must be permitted under CWA Section 402 through NPDES permits. These permits include both technology- and water quality–based discharge limitations to protect the designated uses of the receiving water. Because of the substantive changes in discharge characteristics, the conversion from once-through cooling to wet cooling towers would require a major modification to the facility's NPDES permit. The power plant would apply for the modification and the permit would be reissued by the appropriate RWQCB. As part of this process, the RWQCB would reevaluate the discharge characteristics and discharge limitations and prohibitions.

For a once-through cooled power plant, the discharge is overwhelmingly dominated by the heated water from the cooling system (greater than 99 percent by volume), with smaller contributions from low-volume wastes such as boiler blowdown, laboratory drains, and facility sumps. Discharges of thermal waste are regulated under the State Water Resources Control Board's *Water Quality Control Plan for Control of Temperature in the Coastal and Interstate Water and Enclosed Bay and Estuaries of California (Thermal Plan),* which includes water quality objectives for temperature. Depending on the final configuration selected for a particular facility, the conversion of once-through cooling system to a wet cooling tower system will likely reduce the temperature of the final discharge and, because the volume is substantially less, will also reduce the size of any associated thermal plume in the receiving water.

A power plant that converts its cooling system to wet cooling towers will no longer discharge once-through cooling water. Instead, the facility will generate cooling tower blowdown, which, if discharged to a surface water, is subject to technology-based effluent limitation guidelines (ELGs) promulgated by EPA at 40 CFR 423.13. These ELGs contain numeric effluent limitations for chromium and zinc (0.2 mg/L and 1.0 mg/L, respectively) and narrative criteria for the remaining priority pollutants (no detectable amount). The ELGs for chromium and zinc were based on the common practice of using chromium compounds, such as chromate-zinc, to inhibit corrosion and fouling in cooling towers. While the use of chromium-based compounds in cooling towers has been prohibited since 1994, the ELGs are still applicable to cooling tower blowdown, including the narrative limitation for priority pollutants.

Many facilities utilize condenser tubes consisting of zinc and copper alloys (brass, bronze, copper-nickel) and may contribute small amounts of these and other metals to the circulating water flow through the effects of corrosion. In addition, trace amounts of these metals may be present in the water used to provide makeup water to the cooling tower. If present, their concentrations in the final discharge would increase according to the cycles of concentration used in the design of wet cooling towers and may trigger an exceedance of the ELGs. Because ELGs are applicable at the point of discharge from the cooling tower and not at the point of final discharge, there is no benefit from dilution that might result from commingling with other waste streams the facility may generate. A facility that exceeds these limitations would be required to adopt treatment measures or possibly secure an alternative source of makeup water for the cooling tower.

Water quality–based effluent limits (WQBELs) are generally derived from two sources, depending on the nature of the receiving water. For ocean dischargers, WQBELs are derived statewide from the Ocean Plan. For inland waters, including estuaries and enclosed bays, WQBELs are derived from the CTR (implemented through the *Policy for Implementation of Toxics Standards for Inland Surface Waters, Enclosed Bays, and Estuaries of California)* and the Basin Plans for each RWQCB. Changes in the volume and composition of the final effluent resulting from a conversion may impact a facility's ability to meet effluent limitations established under these plans due to the concentrating effects of the cooling tower.

Larger mixing zones or additional dilution may be necessary to meet the applicable criteria. In some cases, such dilution may not be available either because of the flow characteristics of the receiving water and/or the existing background pollutant concentrations (e.g., where the receiving water is already listed as impaired under CWA Section 303(d) for the pollutant). Without such dilution, additional treatment may be required to meet the effluent limits. Likewise, intake credits would not be available because the cooling towers alter the physical and chemical makeup of the water by concentrating various pollutants prior to discharge.

4.2.3 SECTION 404

CWA Section 404 is administered by the U.S. Army Corps of Engineers (with oversight by EPA) and protects waters of the United States, including wetlands. The program requires avoidance, minimization, and mitigation for impacts to "jurisdictional" wetlands. Jurisdictional wetlands are delineated based on vegetation, soils, and hydrologic criteria.

Construction of cooling towers in coastal areas would have the potential to impact jurisdictional wetlands if they were present on the site. In this case, a permit from the Corps of Engineers would be required. The permitting process could involve minimizing disturbances to wetlands, the development of compensatory mitigation, and/or participation in a wetland banking program, depending on the extent of impacts and the location of the project.

5.0 AIR QUALITY

Conversion to wet cooling towers would require revisions to facility air quality permits issued by the APCDs/AQMDs. The scope of such revisions is somewhat dependent on the expected increases in emissions associated with the cooling towers, as discussed below.

Significant programs of the CAA pertain to National Ambient Air Quality Standards (NAAQS), New Source Performance Standards (NSPS), New Source Review (NSR), nonattainment area requirements, hazardous air pollutants, and acid deposition control, as described below.

5.1 NATIONAL AMBIENT AIR QUALITY STANDARDS

The NAAQS program addresses pervasive pollution that endangers public health and welfare and has resulted in the establishment of air quality standards for six pollutants: sulfur dioxide (SO_2), nitrogen dioxide (NO_2), particulate matter (PM_{10}), carbon monoxide (CO), ozone (O_3), and lead. States have primary responsibility for ensuring that emissions are maintained at levels consistent with the NAAQS by establishing source-specific requirements in State Implementation Plans (SIPs). CAA Section 110(a)(2) describes the components of a SIP, which include (1) enforceable emission limitations, (2) provisions for developing ambient air quality data, (3) requirements for preconstruction review and approval of major new stationary sources in attainment areas, and (4) preconstruction permitting requirements relating to construction of new sources and the operation of existing sources in nonattainmnet areas. Incorporation of a wet cooling tower system will result in an increase in PM_{10} from the towers themselves (in the form of drift particles that evaporate and leave particulate matter behind). Total stack emissions of PM_{10} and other pollutants may increase if changes to a facility's efficiency result in the combustion of additional fuel.

5.2 NEW SOURCE PERFORMANCE STANDARDS

EPA has identified certain stationary source categories and promulgated NSPS for those industrial categories—technology-based emission limitations that are imposed on new or modified sources. EPA has promulgated NSPS for (1) fossil fuel–fired steam generators built or modified after August 17, 1971, and (2) fossil fuel–fired steam generators built or modified after September 18, 1978. Both apply to new or modified units with thermal input rates greater than 250 MMBTU/hr, and both strictly control PM_{10}. Emission sources built prior to 1971 are exempt from the NSPS unless they are modified or reconstructed. NSPS regulations are more general (than New Source Review) and are based on what is technologically and economically feasible within an industrial category.

5.3 NEW SOURCE REVIEW

NSR requirements are more site and project specific than NSPS and allow state regulating authorities to set stricter limitations based on what they determine to be the best technology currently available. The CAA designates "major emitting facilities" that are subject to the NSR program, including fossil fuel–fired steam electric plants of more than 250 MMBTU/hr heat input that emit, or have the potential to emit, 100 tons per year or more of any air pollutant. The NSR program then distinguishes between areas where NAAQS are met and nonattainmnet areas.

Major emitting sources in attainment areas that are being constructed or modified must undergo PSD (prevention of significant deterioration) permitting and must implement the best available control technology (BACT). In nonattainmnet areas, the lowest achievable emissions rate (LAER) applies to such sources. BACT and LAER are technology-based standards and must be as stringent as, or more stringent than, the applicable NSPS emission limitation.

For existing plants to trigger NSPS or NSR, two criteria must be satisfied: (1) there must be a physical or operational change and (2) there must be a significant net emissions increase. EPA defines "significant net emissions increase," differently for the two programs, using a total annual emissions test (tons or kg/yr) in the NSR program and using an emissions rate test (tons or kg/hr) for NSPS purposes. If a modification results in an increase in emission rate to the atmosphere of any pollutant to which a standard applies, the source must comply with the NSPS requirements for its industrial category.

For power plants, an important threshold is the emissions of PM_{10}. A cooling tower would increase the total PM_{10} emissions from a facility, although the increase would be based on the capacity utilization for the facility. The threshold for determining a significant net emissions increase is 15 tons per year. This analysis has assumed the use of high-efficiency air pollution controls (drift eliminators) to minimize PM_{10} emissions from cooling towers. These controls represent the accepted BACT for cooling towers. Even with these controls, however, some of the towers may trigger NSR for the entire facility. This would involve BACT or LAER evaluations of all emission sources at the plant as part of the permit modification process. Many of the plants may already have scrubbers or pollution control equipment that meets BACT or LAER requirements, but a final determination of what additional controls could be required and the associated costs is beyond the scope of this analysis.

5.4 STATE NONATTAINMENT AREAS

All the power plants addressed by this study are located in areas designated as nonattainment for PM_{10} as required by Health and Safety Code Section 39608. As a result, the State Air Resources Board and the APCDs/AQMDs have established plans that will lead to future attainment. These plans have specific provisions to allow for new sources. In addition to requiring control technologies, retrofit facilities may have to acquire PM_{10} credits within the airshed to offset any increased emissions. A principal hurdle to securing credits is determining their availability and total cost. In some airsheds, such as the Los Angeles Basin, credits may be unavailable in sufficient quantities. Such an analysis is beyond the scope of this study but could impact the permittability and cost of conversions. Table 3-1 describes state and federal ambient standards. Figure 3-1 shows the county-level attainment status for state PM_{10} ambient air quality standards.

Table 3-1. State and Federal PM_{10} Ambient Air Quality Standards

	California ARB	U.S. EPA
Annual Average	20 $\mu g/m^3$	N/A
24-Hour Average	50 $\mu g/m^3$	150 $\mu g/m^3$

Figure 3-1. State PM10 Attainment Status

5.5 HAZARDOUS AIR POLLUTANTS

CAA Section 112 includes several provisions that address the emission of hazardous air pollutants, including a requirement that EPA establish technology-based emission standards for sources of 188 specifically identified pollutants that reflect the maximum achievable control technology (MACT). Of interest to the electric power industry, at 40 CFR 63.400, EPA has established National Emission Standards for Hazardous Air Pollutants for Industrial Cooling Towers; these standards, however, simply prohibit the use of chromium-based water treatment chemicals in cooling tower systems and have been effect since 1994.

5.6 ACID DEPOSITION CONTROL

The CAA acid deposition program caps SO_2 emissions at existing sources through a tonnage limitation and at future plants through an allowance system; new sources must obtain allowances or offsets from existing sources that hold allowances or authorization to emit specified amounts of SO_2. EPA has also established NO_x emission standards for several types of boilers and has established NSPS for NO_x emitted from fossil fuel–fired steam generating units.

Local and state requirements and Clean Air Act programs, including those pertaining to NAAQS, NSPS, NSR, air toxics, and acid rain, are controlled by operating permits, which include emission limitations, schedules of compliance, and monitoring requirements as well as requirements regarding self-reporting and certification of compliance.

Operating permits are typically valid for five years; however, permittees must seek a permit revision if changes (such as retrofitting to install cooling towers) trigger a requirement that had not previously been applicable, e.g., NSR. Minor permit revisions are subject to limited review requirements and streamlined procedures, whereas significant permit revisions are subject to all procedural requirements applicable at the time of permit issuance.

6.0 GREENHOUSE GASES

6.1 EXECUTIVE ORDER S-3-05

On June 6, 2005, the governor of California signed Executive Order S-3-05, establishing the following targets for reduction of greenhouse gas emissions:

- By 2010, reduce greenhouse gas emissions to 2000 levels.
- By 2020, reduce greenhouse gas emission levels to 1990 levels.
- By 2050, reduce greenhouse gas emission levels to 80 percent below 1990 levels.

The state's Climate Action Team is tasked with implementing global warming emission reduction programs and reporting on the progress made toward meeting the emission targets established in the executive order.

6.2 ASSEMBLY BILL 32

Assembly Bill 32 is also known as the California Global Warming Solutions Act of 2006. Regulations have yet to be promulgated to support this act. The legislature acknowledges, however, that the Climate Action Team established by the governor to coordinate the efforts set forth under Executive Order S-3-05 will continue its role in coordinating overall climate policy. The act charges the State Air Resources Board with responsibility for monitoring and regulating emissions of greenhouse gases, including (1) developing regulations to require reporting and verification of statewide greenhouse gas emissions, beginning with categories of sources that represent the largest contributors of greenhouse gas emissions; (2) determining what the statewide greenhouse gas emissions level was in 1990 and establishing a greenhouse gas emissions limit at that level to be achieved by 2020; and (3) by 2011, adopting regulations, to become effective on January 1, 2012, establishing greenhouse gas emission limits and emission reduction measures to achieve maximum technologically feasible and cost-effective reductions in greenhouse gas emissions.

6.3 SENATE BILL 1368

Senate Bill 1368 builds on Executive Order S-3-05 and establishes policy requiring the consideration of greenhouse gas emissions when long-term electricity procurement decisions are made, and the development of performance-based emissions standards to be linked to long-term electricity procurement. The enactment of Senate Bill 1368 established the following requirements:

- A performance standard for greenhouse gases for all "baseload generation of load serving entities" based on greenhouse gas emissions for combined cycle natural gas baseload generation.
- A performance standard for greenhouse gases for all "baseload generation of local publicly owned electric utilities" as those facilities are defined in Section 9604 of the Public Utilities Code. The standard is again based on the rate of greenhouse gas emissions for combined cycle natural gas baseload generation and, in effect, will be applicable to local publicly owned electric utilities.
- No "load serving entity" or "local publicly owned electric utility" may enter into a long-term financial commitment, nor may the CEC approve a long-term financial commitment by an electrical corporation, unless the baseload generation supplied complies with the greenhouse gas emissions performance standards that are established.

On January 25, 2007, the CPUC adopted the Interim Greenhouse Gas Emissions Performance Standards for all baseload generation of investor-owned utilities, requiring new long-term commitments for baseload generation to come from power plants with greenhouse gas emission rates comparable to combined cycle facilities—a rate equivalent to 1.1 lb/kWh, or a heat rate of approximately 9,600 BTU/kWh for a natural gas facility. Most of the generating units covered in this study are utilized to provide capacity to the grid during peak demand periods, particularly during summer months, and have maximum heat rates ranging from 9,300 to 10,500 BTU/kWh (excluding nuclear and combined cycle units).

The conversion to a wet cooling system will impact the efficiency of a generating unit and increase the overall heat rate, which, although small, may be enough to cause an exceedance of the CPUC standard for baseload plants. This could affect the economic viability of a facility, i.e., its ability to negotiate long-term contracts, which could, in turn, affect its ability to secure financing for long-term capital improvement projects such as a wet cooling system retrofit (exclusive of repowering).

7.0 NATURAL RESOURCES

7.1 CALIFORNIA ENVIRONMENTAL QUALITY ACT

The California Environmental Quality Act (CEQA) requires state and local agencies to identify the significant environmental impacts of their actions and to avoid or mitigate those impacts, if feasible. CEQA is applicable to all activities undertaken by public or private entities, including development projects and government decisions that may not immediately result in physical development, when those activities must receive some discretionary approval from a government agency and when those activities may affect the quality of the environment.

CEQA is intended to be used in conjunction with discretionary powers granted to public agencies by other laws. As such, state and local agencies have integrated the requirements of CEQA with planning and environmental review procedures otherwise required by law or by local practice, so that all of those procedures, to the maximum extent feasible, run concurrently, rather than consecutively.

When a project is proposed by a nongovernmental entity, the lead agency for CEQA purposes is typically the public agency with the greatest responsibility for supervising or approving the project as a whole. Lead agencies are responsible for considering the environmental effects, both individual and collective, of all activities involved in a project and must determine whether an EIR, a negative declaration, or a mitigated negative declaration is required for any project subject to CEQA. Lead agencies have authority to require feasible changes in any or all activities involved in a project in order to substantially lessen or avoid significant effects on the environment.

Prior to determining whether a negative declaration or EIR is required for a project, the lead agency must consult with all responsible and trustee agencies. A responsible agency considers only the effects of those activities involved in a project that it is required by law to carry out or approve. Responsible agencies may require changes in a project to lessen or avoid only the effects, either direct or indirect, of that part of a project for which it is responsible. Trustee agencies are state agencies with jurisdiction over natural resources affected by a project.

A lead agency must determine if a proposed project, not otherwise exempt from CEQA, will or will not have a significant effect on the environment. "Significant effect on the environment" means a substantial, or potentially substantial, adverse change in any of the physical conditions within the area affected by the project, including land, air, water, minerals, flora, fauna, ambient noise, and objects of historic and aesthetic significance.

If there is substantial evidence, in light of the whole record before the lead agency, that a project may have a significant effect on the environment, an EIR must be prepared. Following such a determination, the lead agency must notify all responsible and trustee agencies; those agencies must then identify the scope and content of the environmental information that is germane to their responsibilities and shall be addressed in the EIR. Following a determination of no significant effect, the lead agency must adopt a negative declaration to that effect.

As described in Article 9 of the CEQA regulations, an EIR must include the following components:

- Summary of proposed actions and their consequences
- Project description
- Description of the environmental setting, consideration of environmental impacts
- Consideration and discussion of significant environmental impacts
- Consideration and discussion of mitigation measures proposed to minimize significant effects
- Consideration and discussion of alternatives to the proposed project
- Effects not found to be significant
- Organizations and persons consulted
- Discussion of cumulative impacts

Under the CCR sections 15250 and 251, certain agency actions, e.g., those of the CCC and local coastal planning agencies, can be certified as exempt from the CEQA requirement for preparing EIRs, negative declarations, and initial studies. They are not exempt from the other requirements of CEQA, including avoiding significant adverse effects on the environment, wherever possible. Environmental analyses performed for such agencies may be used by other agencies in lieu of an EIR as long as specific requirements in CCR sections 15252 and 15253 are met. In such cases, the exempt agency is designated as the lead agency and the agency adopting the substitute document/analysis is designated as the responsible agency.

Projects may be approved even though a significant effect on the environment may result if the agency makes a fully informed and publicly disclosed decision that (1) there is no feasible way to lessen or avoid the significant effect and (2) specifically identified expected benefits from the project outweigh the policy of reducing or avoiding significant environmental impacts of the project.

CEQA would likely be triggered by the conversion of a facility from once-through cooling to cooling towers. The lead agency for such an action could be the CEC, the APCD/AQMD, local planning authority, or others, depending on the nature of the modification and the regulatory requirements. Alternatively, an agency exempt from CEQA, e.g., the CCC, could be the lead agency. Given site-specific effects and regulatory applicability, the lead agency may be different at each facility.

The level of review required is also likely to vary. In some areas with the potential for significant visual, noise, land use, or other physical, biological, cultural, or social effects, an EIR may need to be prepared. For other facilities where the effects are less significant, a mitigated negative declaration may be appropriate. In addition, under CCR Section 15887, the regulatory agency that adopts the conversion requirement will need to comply with CEQA and likely prepare an EIR for adoption of the regulation or policy. Under Section 15888 of the California Code of Regulations, a focused EIR could then be prepared for each facility during the permitting process that only describes effects not originally addressed by the statewide EIR.

Consistent with CEQA requirements, a range of mitigation measures could be required in a cooling system conversion to mitigate effects on physical, biological, cultural, and social resources.

7.2 ENDANGERED SPECIES ACT

The Endangered Species Act (ESA) is administered by the U.S. Fish and Wildlife Service (USFWS) and the National Marine Fisheries Service (NMFS), which share responsibility for protecting "listed" plant and animal species and their critical habitat (when critical habitat is identified). Generally, USFWS manages land and freshwater species, while NMFS manages marine and anadromous species. Section 10 of the ESA applies to projects undertaken in the private sector. If a nonfederal entity, including a private landowner, proposes to undertake an activity that might incidentally (not intentionally) "take" a listed species, they must obtain an incidental take permit from the USFWS or NMFS. A request for an incidental take permit includes the preparation of a Habitat Conservation Plan, which is designed to minimize and mitigate any potential effects the activity may have on the species. The presence of threatened or endangered species (or designated critical habitat) would need to be assessed prior to any construction of new facilities (e.g., cooling towers).

7.3 CALIFORNIA ENDANGERED SPECIES ACT

The California Endangered Species Act (CESA) is administered by the California Department of Fish and Game (CDFG) to protect state-listed threatened, endangered, and candidate species. Similar to the incidental take permit available under the federal Endangered Species Act, the CDFG can issue an incidental take permit for activities meeting specific criteria. Criteria for an incidental take include impacts being minimized and mitigated, with mitigation measures being roughly proportional to the extent of the impact on the species. Adequate funding of mitigation activities is also a requirement for issuance of the incidental take permit.

7.4 FISH AND GAME CODE

The Fish and Game Code is administered by CDFG for the protection and conservation of the fish and wildlife resources of the state. The code includes the following:

> **Section 1602. (a)** An entity may not substantially divert or obstruct the natural flow of, or substantially change or use any material from the bed, channel, or bank of, any river, stream, or lake, or deposit, or dispose of debris, waste, or other material containing crumbled, flaked, or ground pavement where it may pass into any river, stream, or lake, unless... specific conditions defined within the code are met.
>
> **Section 1603. (a)** After the notification is complete, the department (CDFG) shall determine whether the activity may substantially adversely affect an existing fish and wildlife resource.... The draft agreement shall describe the fish and wildlife resources that the department has determined the activity may substantially adversely affect and include measures to protect those resources.

7.5 CALIFORNIA NATIVE PLANT PROTECTION ACT

The California Native Plant Protection Act is also administered by the CDFG to preserve, protect, and enhance rare and endangered plants in the state. Enacted prior to the CESA, the Native Plant Protection Act extends protections to plants that are considered "rare," in addition to those designated threatened or endangered. Requirements under the act are not as stringent as under the CESA; mitigation measures for impacts to rare plants are identified in a formal agreement between the project proponent and the CDFG.

8.0 SUMMARY

As noted above, a range of regulatory and permitting/approval requirements affect the conversion from once-through cooling to a wet cooling tower system. The specific requirements that will apply to individual facilities vary on a site-by-site basis. In addition, the roles and responsibilities of each agency will also vary for each site. For facilities that were originally permitted by the CEC, or where the project involves the addition of ≥50MWe of generating capacity, the CEC will generally be lead agency for the permitting and review process. Where CEC does not have a role, the lead agency could be the CCC or local coastal planning agency, the RWQCB, the SLC, or another agency that regulates local development, such as BCDC.

In summary, conversion of once-through cooling systems to wet cooling towers

- Is consistent with the Ocean Protection Council resolution discouraging the use of once-through cooling, but does not call for conversion to closed-cycle cooling immediately.
- Will achieve compliance with RWQCB requirements for compliance with CWA Section 316(b). Though each plant must be evaluated individually, significant intake reductions may obviate the need for an NPDES permit for the intake structure, though a permit will be required for discharge structures under Section 402 of the CWA.
- Is consistent with the EAP's goal of enhanced environmental protection. At the same time, the minor loss of efficiency may be inconsistent with other goals. The agencies involved in permitting will have to coordinate their actions to ensure compliance with the EAP. Overall, the EAP is not expected to preclude conversion, since the first priorities are energy conservation, development and use of renewable resources, and ensuring generation and distribution system reliability.
- Must be addressed with respect to long-term statewide and regional planning for climate change. A more immediate issue may be the CPUC's recent determination to limit long-term contracts with baseload facilities to those with heat rates not exceeding 9,600 BTU/kWh. Retrofitting to wet cooling towers could cause a facility's heat rate to exceed this threshold and impact long-term economic viability.
- Is consistent with the California Coastal Commission's goal of conserving marine resources but may necessitate site-specific mitigation to address requirements to protect visibility, recreation, habitat, and land use resources.
- Will alter effluent characteristics and require modification of the facility NPDES permit (if effluent discharge is maintained). Increased concentrations of some pollutants, combined

with requirements to meet ELGs for cooling tower blowdown, may compel some facilities to adopt additional treatment systems or secure alternative discharge measures.

- Is not likely to be precluded by CAA permitting requirements. Conversion will likely trigger NSR at some facilities due to increased particulate emissions. This would necessitate facilitywide evaluation of control technologies and may require new or additional controls. In PM_{10} nonattainment areas, facilities may have to obtain PM_{10} emission reduction credits.
- Must address the unique design and safety criteria present at nuclear facilities and ensure that any proposed retrofit complies with applicable NRC design and safety regulations.
- Will require a determination of CEQA compliance, although the level of analysis will vary by site. At sites with limited impacts, a mitigation negative declaration may suffice. At other sites, particularly those with potentially significant land use, visibility, air quality and other impacts, an EIR may be required. A range of mitigation measures may also be required to address any effects on physical, biological, cultural, and social resources.

4. CLOSED-CYCLE COOLING SYSTEMS

1.0 BACKGROUND

Closed-cycle cooling systems are an increasingly common technology used to provide the necessary heat rejection for steam electric power plants. Environmental and regulatory trends have made these systems—both wet and dry cooling—the nearly universal cooling option for newly-constructed power plants. California reflects this trend as well, with new and repowered facilities adopting this approach and reducing impingement and entrainment impacts to California's coastal waters.

Unlike screening technologies, closed-cycle systems, as a retrofit technology, will more broadly affect a facility's operation and may trigger other environmental effects that may require mitigation of their own. These effects may be more pronounced at an aging facility that is less efficient and more susceptible to process changes.

This chapter provides general background information on the types of closed-cycle cooling systems their function and some secondary effects of their use as a retrofit technology.

2.0 HEAT TRANSFER

The function of any cooling technology is to transfer waste heat from the turbine to the environment as efficiently as possible. In a wet cooling system, heat rejection from a cooling tower is primarily due to the evaporation, or latent heat, of water into the surrounding air and is responsible for approximately 80 percent of the tower's cooling capacity. Sensible heat transfer, which results from the direct contact between warm water and cooler surroundings, provides the remaining 20 percent. In either a natural or mechanical draft tower, latent and sensible heat transfer must be maximized in order to achieve the full cooling capacity at the most economically efficient rate (Hensley 2006). Dry cooling systems, as the name implies, do not use water as a cooling medium and instead rely on sensible heat transfer only.

Because wet cooling towers rely primarily on evaporation, their overall efficiency is governed by the differential between the circulating water temperature in the tower and the wet bulb temperature of the ambient atmosphere. The wet bulb temperature measures the ambient air temperature (also referred to as the "dry bulb" temperature) and the relative humidity of the surrounding atmosphere. By accounting for the saturation level of the atmosphere, the wet bulb temperature represents the additional cooling capacity that can be exploited by wet cooling towers through evaporation. Thus, wet cooling towers function most efficiently in environments where the relative humidity is low and the surrounding atmosphere can more rapidly accommodate evaporative heat loss. This does not preclude their use in more humid environments, however, since the wet bulb temperature, on average, will always be lower than the dry bulb temperature (Hensley 2006).

In theory, a wet cooling tower can lower the temperature of the circulating water to the ambient wet bulb temperature if sufficient evaporation is achieved. In practical application, however, this is not feasible due to the diminishing ability of the tower to induce evaporation in the circulating water as the temperature decreases. A wet cooling tower designed to achieve the ambient wet bulb temperature would need to be extraordinarily large in order to achieve the desired air-water interaction to facilitate the necessary evaporation. Instead, the design of wet cooling towers is based on the "approach" temperature, which is the difference between the temperature of the water exiting the cooling tower and the ambient wet bulb temperature.[1]

The approach temperature is critical to estimating the overall size and cost of the cooling tower, and is fixed prior to design based on the ambient conditions and the desired cooling capacity. Common industry practice does not call for the design of a wet cooling tower with an approach temperature that is less than 5ºF. In general, as the wet bulb temperature decreases the economically achievable approach temperature will increase. An accepted industry practice is to start with an approach temperature of 10ºF and adjust upwards if site-specific conditions warrant (Hensley, 2006). In general, as the wet bulb temperature decreases the economically achievable approach temperature will increase.

Dry cooling systems rely solely on radiation and convection to reject heat from the steam cycle. Their overall efficiencies are largely governed by the dry bulb temperature of the surrounding atmosphere. The dry bulb temperature is synonymous with what is commonly referred to as "air temperature" and is measured using a thermometer freely exposed to the air but shielded from any radiation source (sunlight) or moisture condensation. Except when the relative humidity is 100 percent and the dew point is equal to the air temperature, the dry bulb temperature will always be higher than the corresponding wet bulb temperature.

Like wet systems, dry systems are also limited in how close they can come to approximating the governing cooling variable (dry bulb). As a dry system approaches the dry bulb, the efficiency of the system drops off dramatically and requires an increasingly larger cooling surface area to achieve progressively smaller gains in cooling capacity. Costs will also increase substantially as the system and its associated operational demands grow, making the diminishing returns of a large system designed to maximize the theoretical cooling capacity economically unpalatable (Hensley 2006). Instead, the level of cooling in a dry system is a function of the initial temperature difference (ITD), which reflects the difference between the dry bulb temperature of the ambient atmosphere and the temperature of the steam condensate in the system.

A lower ITD in a dry system translates to a cooler steam condensing temperature and a lower backpressure at the steam exhaust point, which in turn limits the loss of turbine efficiency. Lower ITD values enable a facility to operate under more demanding conditions, but are comparatively larger and require more operating power than a system designed for a higher ITD. For example, a system with an ITD of 20 ºF might have an initial capital cost 67 percent higher than a comparable system designed with an ITD of 35 ºF. Operating costs might be twice as high or more (EPRI 2002b), although these costs will be partially offset by the increased efficiency.

[1] Under certain conditions, the ambient wet bulb temperature used for design purposes may be increased if the arrangement of the cooling tower cells or local climate factors results in the reuptake or recirculation of the warm, humid tower exhaust. This modified temperature is referred to as the "entering wet bulb."

While design ITD values vary from place to place depending on the relative climatic conditions, recent applications have used design ITD values ranging from 35 to 45 ºF, which are considered applicable to coastal sites in California.

3.0 EVAPORATIVE COOLING SYSTEMS

Evaporative cooling systems, more often referred to as “wet cooling towers”, function by transferring waste heat to the surrounding air through the evaporation of water, thus enabling the reuse of a smaller volume of water several times to achieve the desired cooling effect. Compared to a once-through cooling system, wet cooling towers may reduce the volume of water withdrawn from a particular source by as much as 97 percent depending on various site-specific characteristics and design specifications. The environmental benefits associated with a closed-cycle system, through their reduced water use, may be substantial when compared to a once-through system but are not without significant drawbacks of their own.

Consideration must be given to other environmental impacts (air emissions, visual, noise, etc.) that may result from the use of a closed-cycle system and the comprehensive cost associated with its installation and operation. In a retrofit situation, where a wet cooling tower is proposed to replace a once-through cooling system, these impacts may be greater, and come at a higher cost, than for a facility that adopts closed-cycle cooling from the start.

3.1 NATURAL DRAFT COOLING TOWERS

Wet cooling towers are classified into two broad categories depending on the mechanism used to induce draft—the flow of cooler, drier air through the tower: natural or mechanical. The term “cooling towers” usually calls to mind the tall, hyberbolic shape of natural draft cooling towers (Figure 4–1). These towers rely on the naturally-occurring chimney effect that results from the temperature difference between warm, moist air at the top of the tower and cooler air outside. . Fans are not required to maintain the flow of air, but hyperbolic towers must be fairly tall to achieve the desired temperature differential. The overall height of these structures can approach 500 feet or more.

Natural draft towers were not considered at any of the coastal power plants that are part of this study, primarily due to the increased cost and difficulty of placing such large structures at existing facilities. All of the coastal power plants in California are located within Seismic Zone 4 of the Uniform Building Code (UBC) (ICBO 1997). Standards for this zone are the most stringent with regard to structural integrity and resistance to damage, and result in substantial increases in design and construction costs for progressively taller structures. In addition, placement of obtrusive structures 450 feet tall or more in the California Coastal Zone is unlikely at many locations given the Coastal Act’s requirement that “development shall be sited and designed to protect views and… to be visually compatible with the character of surrounding areas, and where feasible, to restore and enhance visual quality in visually degraded areas.” In many of the highly developed areas where California’s coastal power plants are located, the cost and regulatory considerations, in addition to the likely local opposition, are not justified when compared to less-costly and less-obtrusive options that can achieve similar results.

Figure 4–1. Natural Draft Cooling Tower

3.2 MECHANICAL DRAFT COOLING TOWERS

Mechanical draft cooling towers rely on motorized fans to draw air through the tower structure and into contact with the water. Without the same need for height as natural draft towers, the mechanical draft design presents a much lower visual profile against the surrounding area with typical heights ranging from 30 to 75 feet, depending on local constraints and design considerations. The overall area devoted to cooling towers, however, may be comparable to natural draft units since one mechanical draft unit, or "cell", has a smaller cooling capacity. Mechanical systems are arranged into multi-cell units, which are collectively referred to as the cooling tower, and can be placed in a single row (inline) or back to back. Although often more feasible, and in some cases more practical, than natural draft towers, mechanical systems place an added draw on the facility's net generating output in order to operate the fans that induce the draft. Figure 4–2 shows a multi-cell mechanical draft cooling tower in an inline configuration.

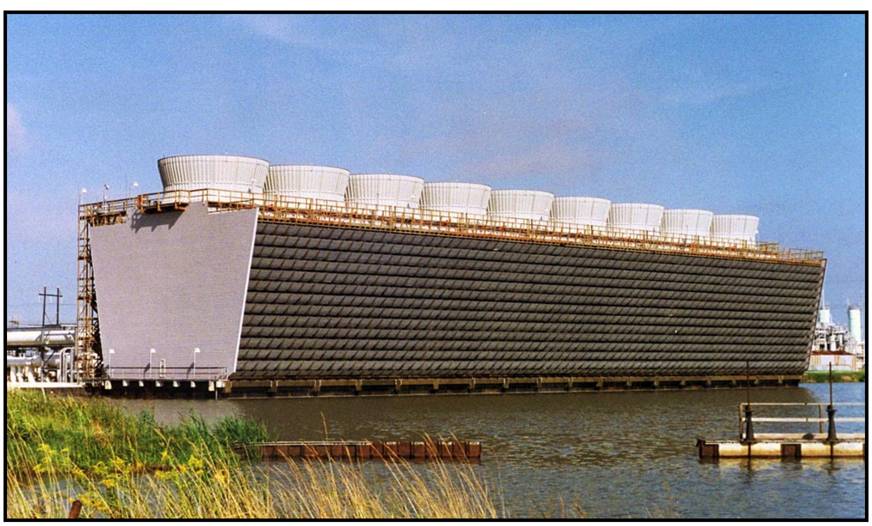

Figure 4–2. Multi-cell Mechanical Draft Cooling Tower

3.3 SALTWATER COOLING TOWERS

In the past, wet cooling towers were considered to be ill-suited for seawater applications due to the more corrosive effects of salt on construction materials, the degradation of the condenser performance due to scaling and the reduced rate of evaporation resulting from salt concentrations in the circulating water (Ying and Suptic 1991). Advances in tower design and construction materials have enabled cooling towers to be successfully deployed in numerous locations with high salinity water. Table 4–1 contains a list of facilities that have deployed wet cooling towers in high salinity environments (Marley 2001).

Table 4–1. Installation of Seawater/Saltwater Cooling Towers

Location	Project Owner	Design Flow (MGD)	Installation Year
Oklahoma, USA	Oklahoma Gas & Electric Company	87	1953
Kansas, USA	American Salt Company	7	1964
New Jersey, USA	Exxon Chemical Company	32	1968
Stenungsund, Sweden	ESSO Chemical AB	146	1969
Judibana Falcon, Venezuela	Lagoven Amuay	49	1970
Okinawa, Japan	Exxon Petroleum Company	21	1971
Florida, USA	Gulf Power Company	239	1971
Texas, USA	Dow Chemical Company	87	1973
Maryland, USA	Potomac Electric Power Co. Plant 3	376	1974
Virginia, USA	Virginia Electric Company	477	1975
North Carolina, USA	Pfizer Company	79	1975
California, USA	Dow Chemical Company	17	1976
Washington, USA	Italco Aluminum Company	59	1976
California, USA	Pacific Gas & Electric Company	538	1976
Texas, USA	Houston Lighting & Power Company	347	1977
Mississippi, USA	Mississippi Power Company	250	1980
Maryland, USA	Potomac Electric Power Co. Plant 4	376	1981
Arizona, USA	Palo Verde I Plant	849	1985
Arizona, USA	Palo Verde II Plant	849	1986
Florida, USA	Stanton Energy #I Station	289	1986
Arizona, USA	Palo Verde III Plant	849	1987
Texas, USA	Houston Lighting & Power Company	348	1987
Delaware, USA	Delmarva Power & Light	293	1989
California, USA	Delano Biomass Energy Company	28	1991
Florida, USA	Stanton Energy #2 Station	289	1995

Most cooling towers today, especially those in seawater environments, are built with materials that are more corrosion resistant than were used in the past (e.g., pressure treated wood) and designed for lower cycles of concentration to minimize impacts on the condenser. This lower cycle of concentration, however, means that a saltwater tower using seawater will often require more makeup water than a tower using freshwater.

All of the facilities in this study currently use seawater or brackish water for cooling in once-through cooling systems. Given the increasing demands on freshwater sources throughout California and state policies discouraging the use of freshwater as a cooling water source, all cooling towers designed in this study are assumed to rely on saltwater or brackish water as the makeup water source.

The average concentration of dissolved solids for seawater is approximately 35 parts per thousand. Input from cooling tower vendors and data from other seawater applications suggest that 1.5 cycles of concentration is an acceptably conservative estimate on which to base tower design specifications. The principal tower construction materials for facilities evaluated in this study are fiberglass reinforced plastic (FRP) and prestressed concrete cylinder pipe (PCCP) suitable for seawater application, unless site-specific factors warrant another selection.

Additional information describing the use of saltwater cooling towers can be found in the CEC's 2007 report, Cost, Performance, and Environmental Effects of Salt Water Cooling Towers.

3.4 GENERAL DESIGN AND CONFIGURATION

Wet cooling towers are designed with fill materials that promote heat transfer by maximizing the contact between a volume of water and the air flowing through the system. Splash fill creates smaller and smaller droplets by disrupting the cascading flow of water from top to bottom. Film fill draws water into progressively thinner sheets as it flows downward. Each method increases the surface area to volume ratio of the water, which in turn maximizes the heat transfer potential.

The heat transfer rate is also influenced by the relative water-to-air direction inside the tower structure. Crossflow towers place fill material along the inside perimeter of the structure surrounding a vacant central column, with water distributed through the fill material (rain zone) by a gravity flow system. Air is drawn horizontally through the rain zone before exiting vertically through the fan (Figure 4–3). Counterflow towers arrange fill material throughout the structure and use pressurized spray nozzles to distribute the water evenly through the rain zone. Air is drawn vertically through the tower in direct opposition to the falling water (Figure 4–4).

Counterflow towers are generally more efficient than crossflow towers because they tend to provide greater interaction between air and water in a given space. To achieve the same degree of cooling, a crossflow tower will be somewhat larger or require more individual cells, thus increasing initial construction costs and the overall tower footprint. Counterflow towers require marginally greater pumping capacities because of the design, but any increase in cost is considered insignificant and does not outweigh the advantages that they provide over the crossflow design. With available space at California's coastal facilities often limited, the need to maximize cooling capacity in relation to the overall tower footprint was a primary consideration in this study; all tower designs are counterflow.

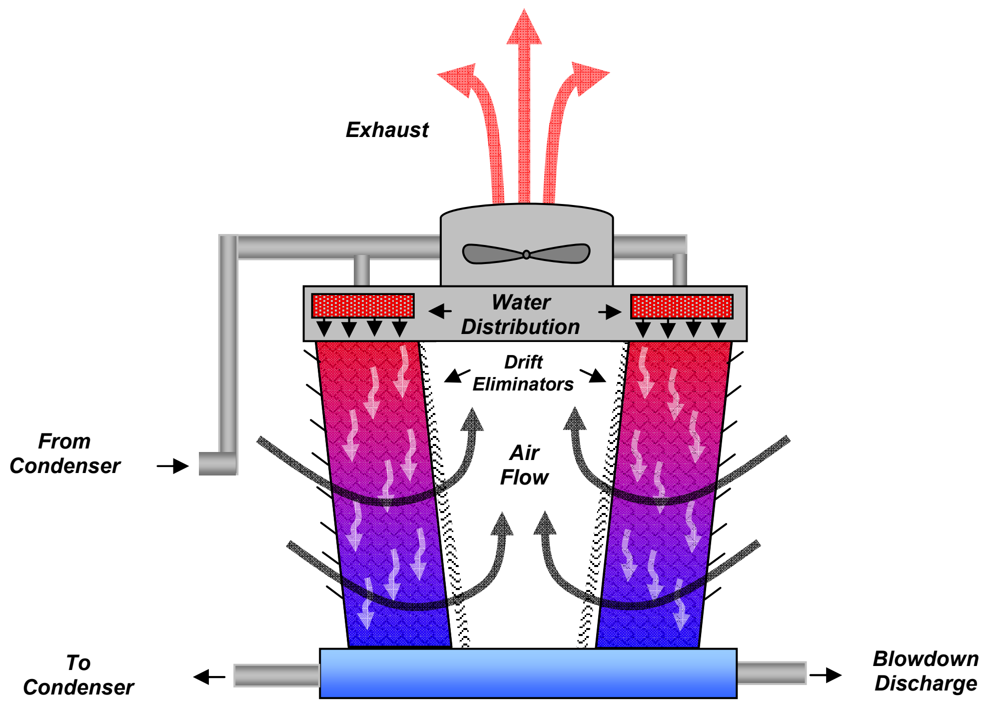

Figure 4–3. Crossflow Cooling Tower

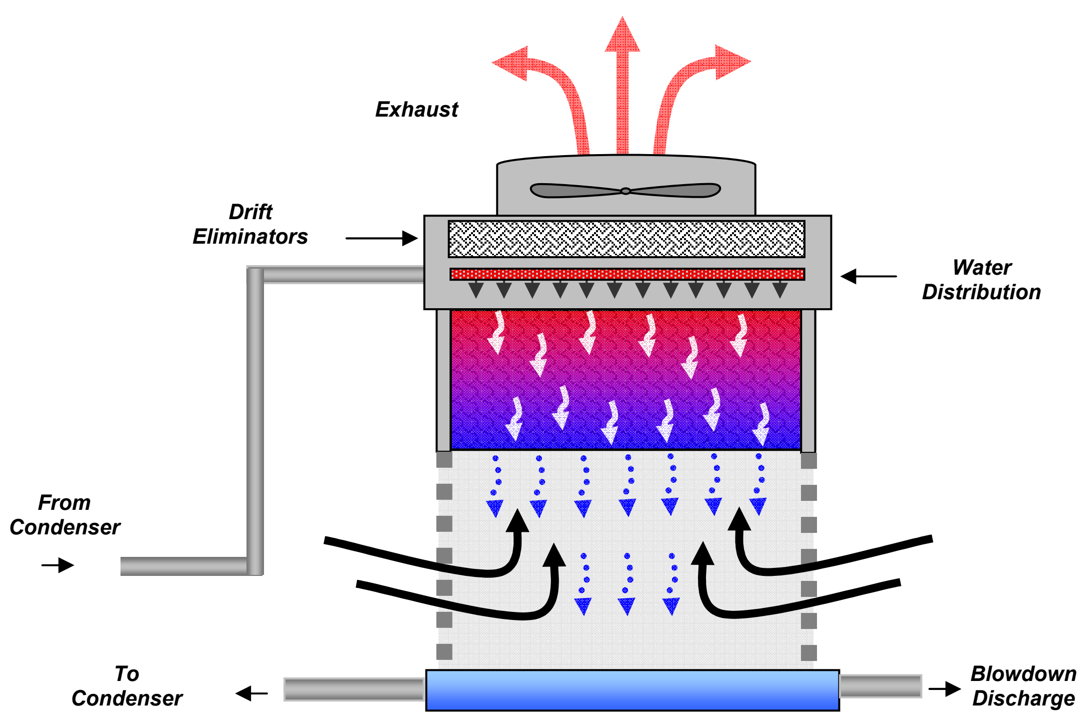

Figure 1–4. Counterflow Cooling Tower

3.5 SECONDARY ENVIRONMENTAL EFFECTS

Retrofitting a once-through cooling system with wet cooling towers will dramatically reduce the amount of water withdrawn from California's coastal waters up to 95 percent below their current levels and achieve a similar reduction of impingement and entrainment impacts as well. In most cases, converting to wet cooling towers will also reduce the size of any thermal plume in the receiving water, often at much cooler temperatures as well. These benefits do not come without some tradeoffs with secondary environmental effects, however, and may present permitting challenges that require mitigation measures or additional considerations.

The principal secondary effects relate to increased air emissions, visible plume and drift, and changes to the wastewater discharge.

3.5.1 FINE PARTICULATE MATTER

The principal air pollutant emitted directly from wet cooling towers is small particulate matter. Dissolved solids in the circulating water result in fine particulate emissions (PM_{10}) when water droplets are ejected from the tower evaporate before they reach the ground. Total PM_{10} emissions can be conservatively estimated by assuming the full concentration of dissolved solids in any exiting water droplets will be converted to airborne PM_{10}. This method discounts the possibility that some droplets do not evaporate prior to deposition on the ground or structural surfaces and assumes that all particulate matter would be classified as PM_{10}. Some studies have suggested that PM_{10} estimates made with these assumptions may exaggerate actual emission rates from cooling towers (Micheletti 2006).

PM_{10} is a significant concern throughout most of California with nearly all counties designated as non-attainment areas, including all counties in which coastal facilities reside. Regulations for air emissions, including PM_{10}, are set by local Air Quality Management Districts or Air Pollution Control Districts (see Chapter 3) and would restrict cooling tower air emissions. If emission limits are significant enough, a facility retrofitting to wet cooling towers may be required to purchase PM_{10} offsets or reduction credits, although these credits are limited in many areas and would become increasingly expensive with new demand from several retrofitted power plants located in the same district.

Reclaimed water as the makeup water source can mitigate PM_{10} emissions due to its lower dissolved solids concentration. Its use, however, may be limited by the available volume and relative distance between the facility and the source.

Cooling tower particulate emissions are controlled through the use of drift eliminators—shaped materials that collect small water droplets as they exit the tower. All cooling towers evaluated in this study include drift eliminators capable of reducing drift to 0.0005 percent of the circulating water volume, or approximately 0.5 gallons per 100,000 gallons of flow. These eliminators are considered Best Available Control Technology (BACT) for PM_{10} emissions from mechanical draft wet cooling towers.

This study estimated direct PM_{10} emissions from wet cooling towers using the conservative approach using the following equation:

$$PM_{10} = F \times TDS \times C \times E \times 8.34\,{}^{lbm}\!/_{gal} \times 60\,{}^{\min}\!/_{hr}$$

where:

PM_{10}	= fine particulate emissions, in lbm/hr
F	= cooling tower circulating flow, in gpm
TDS	= total dissolved solids concentration in makeup water (3.5%)
C	= cycles of concentration (1.5)
E	= drift eliminator efficiency (0.0005%)

3.5.2 VISIBLE PLUME

Wet cooling towers often produce a visible plume—a column of condensed water vapor resulting from the exhaust's higher temperature and saturation level relative to the ambient atmosphere (Figure 4–5). A plume's density increases as the relative difference between exhaust and ambient temperatures grows. Its persistence is dependent on the speed at which the plume mixes with the ambient air and reduces the water vapor content below the saturation point. Visible plumes are typically more pronounced during winter months, although cool, humid conditions may also produce a substantial plume at any time of the year.

Figure 4–5. Visible Plume

In most cases, a visible plume does not cause any significant environmental impact to the surrounding area since the plume is no different from a cloud or fog. Concerns arise, however, when the plume creates or exacerbates a public nuisance or safety hazard. An atmospheric inversion may result in thick, persistent fog that reduces visibility levels on nearby freeways or bridges. A dense plume that remains aloft may interfere with airport operations and flight pathways. On an aesthetic level, the visual impact of a tall plume may be undesirable if located near commercial or residential areas, or areas designated for public recreational use.

Technologies can mitigate a visible plume's size and frequency and reduce its overall impact, although the initial costs are often substantially higher than a conventional system. One method uses additional fans that induce rapid mixing by drawing ambient air into the exhaust before leaving the tower. Results using this approach are generally mixed and can vary significantly depending on ambient atmospheric conditions; high humidity levels in the surrounding air can limit any plume reduction. A more reliable method combines a smaller dry-cooled component above a conventional wet tower to raise the exhaust temperature and reduce its humidity below the ambient atmosphere's saturation point.

Plume-abated, or hybrid, cooling towers are subject to more restrictive siting criteria than a conventional wet tower. The addition of the dry cooled component will add to the structure's overall height, sometimes by as much as 15 to 30 feet. This may conflict with local zoning ordinances restricting building height and visual impacts. Hybrid towers are more susceptible to the effects of exhaust recirculation and must be located at sufficient distances from other towers and obstructions. Individual cells cannot be configured in a back-to-back arrangement.

The initial capital cost of plume-abated towers is typically 2 to 3 times higher than conventional towers. This study conducted a comparative cost assessment between hybrid and conventional towers for Scattergood Generating Station. For Unit 1, the design-and-build cost estimate for a 6-celled hybrid tower was $10.2 million, while a conventional tower for the same unit cost only $2.9 million (Bruman 2007). This estimate did not include any operating cost increases.

3.5.3 PUBLIC HEALTH

Cooling tower operation can theoretically contribute to public health risks, specifically Legionella pneumophilia (Legionnaire's Disease), if individuals come in contact with contaminated water that has been left stagnant or is insufficiently treated. Legionnaire's Disease can be a significant health risk, especially when contracted by individuals with compromised immune systems or existing respiratory ailments. Annual incidents are rare, however, with little evidence of a wide-ranging threat to public health from properly-maintained cooling towers. Pathogen control in cooling towers is already required by state and federal regulations and is addressed by incorporating sufficient biofouling treatment systems into the initial design and following proper maintenance and worker safety procedures (DiFilippo 2001).

3.5.4 DRIFT

Small water droplets are ejected from the cooling tower as part of the exhaust, some of which may evaporate prior to settling on the surrounding area as drift. High-salinity drift may adversely affect sensitive structures and equipment without sufficient preventative maintenance efforts. At power plants, these concerns are most pronounced when drift settles on switchyards and transmission equipment, which may lead to arcing or flashover and cause significant damage to critical systems. Ideally, cooling towers are located in an area where these impacts are minor or manageable—downwind or at a sufficient distance to allow drift to settle out before coming in contact with switchyards. In saltwater environments, such as along California's coast, sensitive equipment is presumably designed to withstand some degree of salt drift occurring from wind and wave action. Cooling tower drift, however, will have a salinity level that is 50 percent higher than marine water.

Apart from onsite impacts, drift deposition is a relatively localized concern, causing spotting or mineral scaling and contributing to increased corrosion. More often cited, but poorly supported, is the effect of high salinity drift on agriculture. Salt deposition may affect particular crops under narrowly drawn conditions, but has not been shown to be a widespread or significant issue (CEC 2007).

Where possible, this study selected wet cooling tower locations that would minimize drift impacts on sensitive equipment, although space constraints at some sites resulted in less-than-optimal placement. No attempt was made to quantify the cost or considerations involved in relocating or upgrading switchyard equipment.

3.6 WASTEWATER DISCHARGE

Most steam electric power plants in California discharge low volume, or in-plant, wastes along with the main condenser cooling water. These wastes, which can include boiler blowdown, treated sanitary waste, floor drains, laboratory drains, demineralizer regeneration waste and metal cleaning waste, among others, are significantly diluted when combined with the vastly larger volume of cooling water. Reducing the cooling water-related discharge volume, by as much as 95 percent, may alter the characteristics of the final discharge by increasing pollutant concentrations and possibly triggering concerns over whole effluent toxicity, but will also reduce any thermal discharge impacts

3.6.1 PRIORITY POLLUTANTS

For marine dischargers currently regulated under the Ocean Plan or for facilities discharging to inland waters, estuaries or enclosed bays and regulated under a Basin Plan, the California Toxics Rule and the State Implementation Plan (SIP), new dilution models will likely need to be developed. If sufficient dilution is not available, additional treatment or alternative discharge methods may be required, such as the incorporation of submerged diffusers to reduce the thermal and high salinity plumes. For all facilities, cooling tower blowdown wastes are regulated by federal Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities.

EPA promulgated the current ELGs for the steam electric point source category in 1982. At the time, chromium and zinc compounds were commonly used maintenance chemicals to control corrosion and fouling in cooling towers. EPA retained a numeric effluent limitation for these pollutants out of concern that acceptable alternatives were not widely available. To address the possibility that priority pollutants, including chromium and zinc, may be present in cooling tower blowdown as a result of background concentrations or air deposition, EPA stated that cooling tower blowdown ELGs are "applicable only to pollutants that are present in cooling tower blowdown as a result of cooling tower maintenance chemicals" (USEPA 1982). At the discretion of the permitting authority, compliance may be demonstrated through routine monitoring or through mass-balance calculations that show tower maintenance chemicals do not contribute to pollutant levels above the ELGs.[2]

Technology advances and regulatory restrictions enacted since 1982 have largely eliminated the need to use chromium and zinc compounds as cooling tower maintenance chemicals. Furthermore, acceptable substitutes are more widely available and more effective when coupled with corrosion-resistant materials such as FRP, titanium, or stainless steel, which are the preferred design materials for saltwater applications. Despite these changes, ELGs remain an NPDES component and would require a retrofitted facility to demonstrate its compliance.

The concentrating effect of wet cooling towers on some pollutants is more likely to cause conflicts with water quality-based effluent limitations (WQBELs) when background concentrations in the makeup or receiving water are already elevated, or facility-specific load Commission has found that, with respect to the discharge of metals from cooling tower blowdown, "these discharges have not been found to be a problem at operating nuclear power plants with cooling-tower-based heat dissipation systems" and characterized the potential impact as "small or insignificant" (NRC 2003).

3.6.2 THERMAL DISCHARGES

A significant benefit of wet cooling system retrofits, in addition to reduced impingement and entrainment, is the reduced impact on the receiving water resulting from elevated temperature waste discharges. California's coastal facilities, many of which are 40 years or older, are currently regulated for thermal discharge under the California Thermal Plan as existing sources for elevated temperature wastes. Permitted discharge temperatures are based on criteria that seek to protect designated beneficial uses and areas of special biological concern, and range as high as 100ºF in some cases. Thermal plumes can extend long distances from the discharge point and have far-reaching effects on the receiving water. Wet cooling towers, in addition to dramatically reducing the discharge volume and thermal plume, can be configured to discharge blowdown directly from the tower's cold water basin, with a discharge temperature that more closely approximates the receiving water.

[2] Discussions with EPA staff confirmed this interpretation. (Personal communication between Tim Havey, Tetra Tech and Ron Jordan, US EPA. January 24, 2008.)

4.0 DRY COOLING SYSTEMS

Dry cooling systems are so named because the removal of heat from the steam cycle is accomplished through sensible heat transfer (convection and radiation) rather than through latent heat transfer (evaporation) that is characteristic of wet cooling systems. By relying solely on sensible heat transfer, dry cooling systems eliminate the need for a continuous supply of cooling water to the condenser, thus reducing many of the environmental concerns associated with once-through or wet cooling systems—such as adverse impact on aquatic ecosystems, consumptive use of water resources, and plume or drift emissions.

The use of dry cooling systems at steam electric power plants began largely as an alternative to once-through or wet cooling systems in areas where water resources were limited, but their application has expanded over the years in response to other environmental concerns related to the withdrawal and discharge of large volumes of cooling water. While many of the existing applications of dry cooling in the United States are limited to smaller capacity facilities (<150 MW), larger projects are increasing in frequency as regulatory and market pressures minimize some of the disadvantages usually associated with these types of systems. In California, Otay Mesa (510 MW), Sutter (540 MW), and Gateway (530 MW) are examples of larger applications of dry cooled units that have been built, or are underway, in the last decade (CEC 2007b). South Bay Power Plant, Encina Power Station and El Segundo Generating Station (Units 1 and 2), have each proposed to repower units at their facilities and convert the existing once-through cooling systems to dry cooling.[3]

4.1 TYPES OF DRY COOLING SYSTEMS

Dry cooling systems can be broadly categorized as either direct or indirect. Direct systems, also know as air-cooled condensers (ACC), feed the turbine exhaust steam through sealed ducts directly to a fin tube array where air is drawn across and heat is rejected to the surrounding atmosphere, much like a radiator in a car. The tubes are often arranged in an A-frame configuration with a fan drawing air from below (Figure 4–6). The condensed steam is collected in a sump and returned to the boiler for reuse in the turbine. At no point during the cycle is there any contact between the between the outside air and the steam or condensate.

[3] The South Bay project was withdrawn from consideration in October 2007.

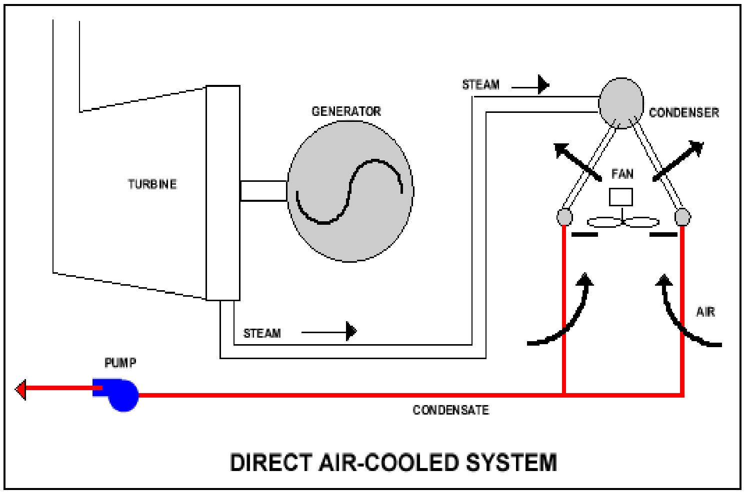

Figure 4–6. Air Cooled Condenser ("Direct Dry")

Indirect dry cooled systems incorporate a surface condenser as an intermediate step between the turbine exhaust and cooling tower. Heat is transferred from the turbine exhaust to the circulating water (or other medium) in the condenser and dispersed to the atmosphere through a fin tube array in a tower, much like the operation of a wet cooling tower. The difference is that, like the ACC, the condenser circulating water is not exposed to the outside air and instead runs in a continuous loop from the turbine to the tower (Figure 4–7).

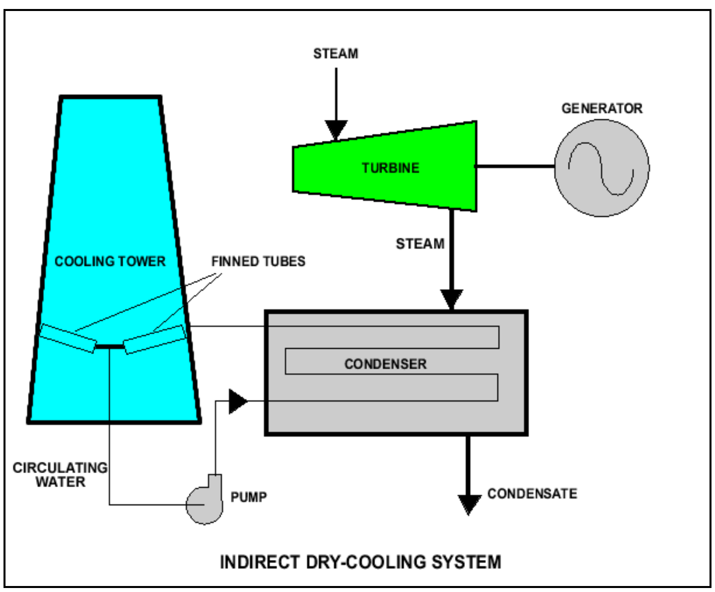

Figure 4–7. Indirect Dry Cooling

The principal disadvantage of an indirect dry cooling system stems from the use of a two-step process to reject heat. The added thermal resistance from the surface condenser reduces the overall heat transfer efficiency of the system. In order to achieve a comparable level of cooling, an indirect system will require a much larger cooling surface area, at increased capital and operational cost, than would be expected for a similar ACC system (Tawney 2003). An indirect system's larger demand for circulating air can be achieved most economically through the use of natural draft towers, which do not require fans. A mechanical draft configuration would require a significant number of fans owing to the increased size of the system and consequently draw a larger percentage of the unit's electrical output for their operation. Without the use of natural draft towers, Heller systems provide no cost advantage over an ACC. At the facilities evaluated in this study, natural draft towers are not considered a viable option, whether for wet or dry systems, due to the concerns over seismic stability and permitting obstacles that would be encountered in sensitive coastal areas.

4.2 DRY COOLING CONSIDERATIONS FOR RETROFIT APPLICATIONS

The decision to adopt a dry cooling system as opposed to a wet or once-through system is fundamentally driven by the relative impacts each system type will have on facility performance weighed against any significant environmental considerations. The overall efficiency of a steam electric generating unit is primarily based on the efficiency with which it can generate electricity from the heat input to the turbine. In a retrofit scenario where a once-through cooling system is replaced with closed-cycle cooling, a dry system will result in less efficient operation than a wet system because of its lower capacity to reject heat from the system.[4] This will increase the heat rate at which the unit generates electricity.

Many units in this study are old (40+ years) and relatively inefficient compared to newer combined cycle units. These inefficiencies contribute to their low capacity utilization levels in recent years as utilities are driven to purchase electricity from more efficient producers. . In addition, the initial capital and operational costs are greater, often significantly so, for dry systems when constructed as part of a new facility (Maulbetsch 2002) and can be expected to be as high or higher in a retrofit application.

Studies conducted by Argonne National Laboratory (ANL 2002) and others have reached largely the same conclusions with regard to cost and feasibility for dry cooling systems as retrofit options and in greater detail than can be presented here.

[4] Assuming a retrofit without substantial modification to condensers or turbines.

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5. ENGINEERING AND COST METHODOLOGY

1.0 OVERVIEW

This chapter presents the step-by-step approach used to determine the feasibility, configuration and cost associated with retrofitting an existing facility's once-through cooling system with a closed-cycle, wet cooling tower system.

A retrofit of this kind is a significant undertaking with many engineering, logistical, and economic considerations that can limit the overall feasibility of converting to closed-cycle technologies. The wet cooling tower design selected for each facility accounts for numerous site-specific factors that influence the type of tower and the overall configuration and represents best professional judgment based on the available data.

These factors include the following:

- General assumptions: these address elements that cannot be definitively captured within this study (e.g., future capacity utilization, makeup water source).
- Logistics: an assessment of what regulatory and physical constraints may exist that limit the design of the tower, or preclude its use altogether (e.g., available area, noise/building height restrictions).
- Site-specific data: facility-specific information describing system operations and limitations that define minimum design requirements for a wet cooling system (e.g., thermal performance, ambient climate data).

Using the conceptual design of the cooling tower, the cost evaluation includes the following components:

- Direct costs: budgetary estimates for all capital projects related to cooling tower installation (e.g., including construction, equipment, materials, engineering, and labor).
- Indirect costs: allowance for smaller project costs that are not specifically itemized (e.g., permitting, startup costs).
- Contingency: allowance to ensure the satisfactory completion of the project by estimating project unknowns that cannot be evaluated in detail (e.g., interference from unidentified infrastructure, accidents).
- Energy penalty: monetizes the increase in parasitic usage as well as the change in thermal efficiency resulting from the operation of the towers.
- Shutdown loss: for some facilities, some disruption to operation will occur as a result of connecting the new system to the condenser, requiring one or more units to be offline.

2.0 ASSUMPTIONS

2.1 GENERATING CAPACITY

A particular generating unit's annual capacity utilization rate is based on numerous factors, such as market demand and contractual obligations, as well as the age and overall efficiency of the unit. Many units in this study are older (30–40 years or more), have lower efficiencies, and are generally provide electricity to the grid intermittently during peak demand periods or when other units are offline. These periods tend to coincide with climate highs and lows, with hot summer months often the only time they will be operational during the entire year.

While these units may operate well below their maximum generating rate on an annual basis, they are likely to operate at or near their full capacity for several weeks or months at a time during peak demand periods, and thus require sufficient cooling capacity to generate the desired amount of electricity. Given that output during this period will likely comprise the majority of revenue the facility will generate during the year, minimizing the loss in efficiency that comes with conversion to a closed-cycle cooling system is a reasonable goal. This requires a larger tower and increases the initial capital cost of the tower, but allows the unit to operate under conditions that more closely approximate the existing once-through system.

On the other hand, because the facility does not generate electricity consistently throughout the year, a cooling tower designed for the peak demand conditions alone would sit idle or be underutilized during much of the year, with a disproportionately higher initial capital cost. A possible trade-off would be to design a smaller cooling tower with lower initial capital costs, but with greater operating costs and efficiency losses.

For this study, it was assumed that the facility would prefer to maximize its output during peak demand periods to maximize its profit without unreasonable losses in efficiency. Accordingly, the cooling towers were designed to provide the desired level of cooling based on the maximum thermal load of the unit(s) served by the tower without triggering capacity limitations.

2.2 FUTURE USAGE

The decision to repower a unit or undertake major upgrades is largely driven by market factors, corporate strategies and contractual obligations that are unknown to this study. Unless specific information is available, it is impossible to predict the future operation of a particular unit or facility. Thus, the wet cooling towers were designed and configured to reflect the current operating conditions and do not consider any potential repowering or replacement projects. Repowering projects, and its possible role with respect to impingement and entrainment reductions, are discussed further in Chapter 1 and Chapter 6.

2.3 CONDENSER SPECIFICATIONS

Heat rejection from wet cooling towers to the surrounding environment is generally more efficient at higher circulating water temperatures. An optimally-designed wet cooling system would account for this by configuring the condenser in such a way to remove more heat from the system on each circuit to and from the tower. At existing once-through facilities, condensers and turbines are generally designed for optimal operation at lower circulating water temperatures. An optimal retrofit would also reconfigure the condenser from a single-pass to a multiple-pass configuration and install new tube bundles. Because more heat is rejected per volume of water using this configuration, the generating unit would be able to operate with a smaller cooling tower that has a lower initial capital cost and lower operating costs over the life of the tower.

For an existing facility, the cost to reconfigure the condenser for service with a cooling tower is likely to be expensive and may require significant construction downtime in addition to material costs. The facility's existing configuration may also complicate this approach if condensers are located below grade or not easily accessible. Re-optimizing a condenser is a more practical alternative at a facility with a long remaining lifespan, during which the facility can recoup initial expenditures through the accrued cost savings from lower operating costs. Aging units with short remaining life are unlikely to realize any overall economic benefit from re-optimization.

In lieu of re-optimization, this study includes a cost allowance to modify the existing condensers for service with wet cooling towers. These modifications are generally limited to water box and tube sheet reinforcements that will likely be necessary for many facilities to withstand the higher the higher circulating water pressures required to elevate water to the top of the cooling tower risers. An allowance for this cost is discussed in Section 6.5. Examples of condenser water box pressure increases are shown in Table 5-1.

Table 5-1. Condenser Pressure Changes

Facility	Condenser description	Condenser water box design pressure (psig)	Estimated back pressure (psig)	Condenser pressure delta (clean tubes) (psig)	Approximate cooling water inlet pressure to condenser (psig)
Haynes	Units 1 & 2, Yuba	25	20	5	25
	Units 5 & 6,	20	20	6	26
	Unit 8, Holtec	50	20	10	30
Moss Landing	Units 6 & 7, Ingersoll-Rand	25	20	5.7	26
	Units 1 & 2, Holtec	80	16	9.8	26
Scattergood	Units 1 & 2,	25	25	4	29
	Unit 3, Hitachi	25	25	8.8	34
Alamitos	Units 1 & 2, Ingersoll-Rand	20	25	9.5	35
	Units 3 & 4, Ingersoll-Rand	20	25	8.2	33
	Units 5 & 6, Ingersoll-Rand	25	25	Not provided	25+
El Segundo	Unit 3, Westinghouse	30	25	6.2	31
	Unit 4, Ingersoll-Rand	30	25	6.3	31
Ormond Beach	Units 1 & 2, Sweco Inc.	25	20	6	26

2.4 WATER USAGE

As discussed Chapter 1, the target reductions of impingement and entrainment impacts were based on the California Ocean Protection Council (OPC) resolution benchmark of 90–95 percent below their current levels. For most facilities, this is accomplished by adopting a closed-cycle cooling system that continues to use the existing marine source water for makeup purposes.

The California State Water Resources Control Board (SWRCB), in 1975, issued a policy statement requiring the consideration of alternative cooling methods in new power plants, including the use of reclaimed water, over the use of freshwater (SWRCB 1975). There is no similar policy regarding the use of marine waters, but the clear preference of state agencies is to encourage alternative cooling methods, including the use of reclaimed water, wherever possible. Water obtained from municipal treatment plants and treated to meet regulatory standards is used for irrigation practices and groundwater recharge projects, and can be used for industrial purposes such as condenser cooling. Some new facilities in California have already adopted this approach, such as the Tesla Power Plant, which uses reclaimed water from the City of Tracy Wastewater Treatment Plant.

The decision to use reclaimed water and further reduce IM&E impacts beyond what can be achieved with a salt water cooling tower is a question of cost-effectiveness; that is, what are the additional benefits that are accrued by eliminating surface water withdrawals altogether and at what cost. These costs may be substantial if, as in many cases in California, long stretches of underground piping must be installed through highly urbanized areas. Onsite treatment systems may also be necessary to ensure the water chemistry and quality is consistent with regulatory requirements and will not adversely impact the performance of the towers and condensers. Contingency measures might also be required to ensure access to a cooling water source in the event of a disruption or reduction of the reclaimed water flow. This may require maintaining a portion of the existing once-through cooling system as a backup.

Competition for reclaimed water sources is likely to increase in the coming years as potential uses expand and municipalities look to alternatives to supplement limited potable water supplies. Orange County, for example, recently completed the first phase of its Groundwater Replenishment System, which will redirect approximately 65 mgd of treated effluent from the Fountain Valley facility for additional treatment. Approximately 50 percent of the produced water will be injected into the seawater intrusion barrier with the remaining portion mixed with other surface waters and allowed to percolate into the groundwater. Current plans call for the system to be expanded in the near future (OCWD 2008).

The use of reclaimed or alternative water sources could potentially eliminate all surface water withdrawals by a particular facility. Doing so would completely eliminate impingement and entrainment concerns, and might enable the facility to avoid possible effluent quality and permit compliance issues, depending on the quality of reclaimed water available for use. Use of reclaimed water, with its lower total dissolved solids (TDS) concentration, allows for the a smaller tower with lower total fan and pump capacity requirements, thus reducing some initial capital and operating costs. The overall cost savings, however, may be negligible if a substantial initial investment must be made to secure a sufficient and consistent reclaimed water source and ensure the necessary level of treatment for use in a cooling tower.

Reclaimed water as a makeup water source may also enable a facility to avoid conflicts with PM_{10} emission restrictions or waste water effluent limitations.

In order to be a practical alternative, reclaimed water must, at a minimum, meet the following criteria:

- Treatment to tertiary standards or ability to provide treatment onsite
- Minimum available flow equal to the design makeup demand
- Relative proximity to the facility
- Consistency of delivery

Information regarding potential sources of reclaimed water is included in each facility's discussion chapter, although all comprehensive cost estimates are developed based on the assumption that the existing marine source water will continue to provide makeup water to the retrofitted system.

More information on the use of saltwater cooling towers is provided in Chapter 4 and the CEC's 2007 report Cost, Performance, and Environmental Effects of Salt Water Cooling Towers.

3.0 LOGISTICS

3.1 LOCAL USE CONSTRAINTS

Many California's coastal power plants are located in highly urbanized settings, with residential and commercial areas in close proximity to the site. As the need for balance between competing uses grows, the guidelines for new development projects, such as wet cooling towers, may become more restrictive. The noise and visual impacts associated with a large wet cooling tower can, in some cases, preclude its installation at a particular location. Local planning and zoning requirements typically address aesthetic and public safety or health concerns, such as noise and visual impacts, associated with a large industrial project.

For each facility, the local regulatory environment was assessed to determine what zoning restrictions and ordinances would have to be met. These requirements are usually found in general development plans or local use plans and obtained from Internet resources. For each facility, the local planning and zoning authority that would have jurisdiction over any large project was contacted in order to verify standards for building height, noise, and visual impacts. In some cases, specific limits were not identified but instead subject to a "conditional use" designation, which evaluates project criteria on a case-by-case basis through a reiterative process between the facility and the regulating agency. In these cases, best professional judgment was used to conservatively estimate the minimum design requirements.

3.2 VISUAL PLUME

Visual plumes, in most cases, do not cause any significant environmental impact to the surrounding area since the plume is no different from a cloud or fog. Concerns arise, however, when the plume creates or exacerbates a public nuisance or safety hazard. An atmospheric inversion may result in thick, persistent fog that reduces visibility on nearby freeways or bridges. A dense plume that remains aloft may interfere with airport operations and flight pathways. On an aesthetic level, the visual impact of a tall plume may be undesirable if located near commercial or residential areas, or areas designated for public recreational use.

Plume-abated ("hybrid") cooling towers are subject to more restrictive siting criteria than are conventional wet towers. The addition of the dry cooled component will add to the total structural height structure, sometimes by as much as 15 to 30 feet. This may conflict with local zoning ordinances relating to building height and visual impact from structures. Hybrid towers are more susceptible to the effects of exhaust recirculation and must be located at sufficient distances from each other while individual cells cannot be configured in a back-to-back arrangement, thus requiring a larger total siting area.

The final decision to use a hybrid wet cooling tower design requires a detailed investigation into the plume's scale, duration and frequency in relation to public hazards and visual impacts to the surrounding area. While threats to public safety from a visible plume may be more readily quantifiable, any evaluation of visual impact will involve a certain degree of subjectivity due to varying understandings of aesthetic value at different locations and the potential tradeoffs between impacts and benefits.

Guidelines furnished by the California Energy Commission (CEC) identify criteria for determining the degree of visual impact a visible plume may have. When the plume's frequency is predicted to occur less than 20 percent of the time during critical period hours (defined as daytime hours November through April with no rain or fog), the plume is considered to have a less-than-significant impact. When the plume is predicted to occur above this threshold, however, a more comprehensive assessment is made of the extent of the visual change imparted by the plume on the local setting, including whether the plume will block prominent landscape features or scenic coastal areas (Knight, 2007).

In lieu of specific criteria, such as zoning restrictions, that would require plume-abated towers, the conceptual design for a particular site included hybrid towers based on best professional judgment and input from cooling tower vendors. In general, hybrid towers were considered only at those facilities where a persistent plume, whether at ground level or aloft, could reasonably be considered a threat to public safety by its interference with major infrastructure, such as airports or freeways.

The preliminary assessment of California's coastal power plants identified El Segundo, Scattergood, Ormond Beach, and San Onofre as the most likely to require plume–abated towers based on their proximity to freeways, airports, or military installations. It is possible that, following a more detailed analysis and local input, other coastal facilities would also be required to adopt the same technology.

3.3 SITE CONSTRAINTS

In order to provide sufficient cooling capacity for a large steam electric power plant, wet cooling towers require a large, contiguous, and open area that will enable their placement away from sensitive equipment and structures. At existing facilities, many of which are located in built-out industrial areas, available land may be at a premium. The cumulative footprint of wet cooling towers and their associated support structures (pumps, piping, etc.) may range from a few acres to several hundred thousand square feet or more, depending on the cooling capacity and type of system required. Available land may not be located in the most desirable area and may present additional challenges, such as an unacceptable proximity to residential or public areas (beaches) or topography unsuitable for major construction.

Wet cooling towers function most efficiently when they are placed longitudinally—or parallel to—the prevailing wind direction at the site. This arrangement decreases the potential for the warm, moist air exiting the tower at the top from being drawn back in through the tower sidewalls. This recirculation will raise the entering wet bulb temperature and decrease the overall cooling efficiency, thereby requiring a larger cooling tower to achieve the same cooling capacity.

This study evaluated the available space for each facility using aerial photos, site development plans, interviews with facility personnel, and/or existing knowledge of the site. If sufficient space could be identified for placement of properly sized wet cooling towers, whether immediately available or through the removal or relocation of existing minor structures, a full engineering and cost evaluation was developed for the particular facility.

In some cases, sufficient space may be available only through the purchase or procurement of adjoining properties. If these locations are unoccupied and do not have any obvious restrictions to their use, the engineering analysis proceeded under the assumption that they could be used for cooling tower siting, although associated costs were not included in the cost analysis. Potential obstacles regarding land acquisition are noted for each facility, where applicable.

4.0 CONCEPTUAL DESIGN

For each facility, cooling towers are sized according to the ambient wet bulb temperature and the desired approach temperature. In most cases, wet bulb temperature data were obtained from the American Society of Heating, Refrigerating, and Air-conditioning Engineers (ASHRAE) design criteria for various areas in California. In designing for peak conditions, the 1 percent wet bulb temperature is used, i.e., the wet bulb temperature that is likely to be exceeded less than 1 percent of the time and is generally representative of the most demanding conditions a facility is likely to experience during the year. Ambient conditions that exceed the 1 percent temperatures may restrict a facility's ability to generate its maximum output.

The approach temperature used for most facilities in this study is based, in part, on the ambient wet bulb temperature and the operating conditions discussed in Section 2.1. Cooling towers can be designed to achieve approach temperatures of 5 to 8º F, but become substantially larger and more costly at progressively lower approach temperatures. To allow a facility to generate its maximum load while keeping initial capital costs reasonable, this study selected a design approach temperature of 12º F in most cases. A 10º F approach was used for Haynes based on initial input from a different cooling tower vendor. A 17º F approach was used for Diablo Canyon based on specific input from that facility.

The final design for each facility's wet cooling tower system is based on best professional judgment and standard best engineering practices. To the degree possible, the design incorporates facility-specific information detailing the performance of the existing cooling system and addresses the various constraints identified for each site. This design serves as the basis for evaluating all secondary effects, such as changes in thermal efficiency, water use, and air emissions and the cost analysis.

5.0 THERMAL EFFICIENCY

A wet cooling system will invariably increase the condenser inlet water temperature compared to a once-through system. This increase in temperature affects the condenser's ability to reject waste heat from the system and raises the backpressure at the turbine exhaust point. Adjustments to the turbine backpressure are a function of the change in steam condensate pressure, which is directly related to the increased circulating water temperature. To obtain the steam condensate pressure, the temperature of the saturated steam condensate must first be calculated using the following equation:

$$Q = \left(U_o \times F_w \times F_m \times F_c\right) \times A \times \left[\frac{\left(T_s - T_i\right) - \left(T_s - T_o\right)}{\ln\left(\frac{\left(T_s - T_i\right)}{\left(T_s - T_o\right)}\right)} \right]$$

where:

Q = condenser thermal load, in BTU/hr
U_o = base heat transfer coefficient, in BTU/hr·ft^2·°F
F_w = temperature correction factor
F_m = tube material factor
F_c = cleanliness factor
A = surface area of condenser, in ft^2
T_s = steam condensate (saturated) temperature, in °F
T_i = condenser inlet temperature, in °F
T_o = condenser outlet temperature, in °F

The effect the change in backpressure has on overall performance is reflected in changes to the unit's operating heat rate. Heat rate adjustments were calculated by comparing the theoretical change in available energy that occurs at different turbine exhaust backpressures, assuming the thermal load and turbine inlet pressure remain constant, i.e., at the maximum load rating. The relative change at different backpressures was compared to the value calculated for the design conditions (i.e., at design turbine inlet and exhaust backpressures) and plotted as a percentage of the maximum operating heat rate to develop estimated correction curves. A comparison was then made between the relative heat rates of the once-through and wet cooling systems for a given month. The difference between these two values represents the net increase in heat rate that would be expected in a converted system.

The heat rate adjustments calculated using the theoretical approach generally agreed with heat rate correction curves provided by some facilities. An example of a heat rate correction curve is shown in Appendix A.

6.0 COST ANALYSIS

6.1 COOLING TOWERS

A principal cost associated with the converting a once-through system to wet cooling towers is the cost of the towers themselves. Large capital projects of this sort are often evaluated as "design-and-build" projects, with vendors providing comprehensive cost estimates that account for nearly all tower construction materials, engineering and design costs, as well as the labor required for construction.

Design parameters were first calculated based on facility-specific information, where available, followed by a conceptual design that incorporated the system requirements and any size, placement, or environmental restrictions that might affect overall cost and feasibility. These elements were then submitted to cooling tower vendors (SPX/Marley and GEA Power Cooling) to develop cost individual cost estimates for each facility.

All design-and-build estimates for wet cooling towers, customized for each facility, include the following:

- Structural materials
- Fill material (splash or film)
- Drift eliminators (0.0005 percent)
- Tower water distribution system (pipes, nozzles, laterals)
- Dry pipe fire suppression system
- Start-up services
- Freight and onsite storage
- Engineering and design
- Installation labor (union), including supervision
- Fans (including gearboxes, supports, drive shafts, motors, switches)

6.2 CIVIL/STRUCTURAL/MECHANICAL/ELECTRICAL COSTS

Various support structures must be built as part of a wet cooling tower retrofit to integrate the new cooling system into the facility. The total cost may be substantial, depending on the size of the tower elements and such factors as distance to the condensers and siting constraints.

Civil and structural costs for each facility include the following:

- Concrete cooling tower basin
- Cooling tower riser piping
- Supply and return piping (including freight and storage)
- Excavation and site preparation
- Sheet piling and dewatering
- Circulating water pumps
- Pump house
- Transformers
- Cables
- Motor control centers
- Lighting
- Lightning protection
- Labor (union) and supervision

Estimates for prestressed concrete cylinder pipe (PCCP), including freight and storage, were provided by Price Brothers Co. Reinforced Plastics, Inc. provided estimates for fiber reinforced plastic (FRP) piping. Electrical costs are based on the battery limit from the main feeder breakers, using recent historical pricing for similar projects evaluated by Hatch, Ltd.

Construction man hours for general labor, mechanical installation, and pipe installation are based on Hatch, Ltd., proprietary databases and estimator expertise. Adjustments for productivity are based on the assumption of substantial similarity to productivity in North America's northeast corridor. Labor rates are based on RS Means (2007) published data and adjusted for the specific region in California where construction will take place. Labor rates are inclusive of the following:

- Organization
- Burden
- Construction equipment
- Site facilities
- Consumables
- Tools
- Protective clothing
- Overhead
- Profit

6.3 FACILITY-SPECIFIC COSTS

Cost components discussed above are not intended to be inclusive for each facility. Additional civil or structural costs may be incurred if site conditions warrant. These may include noise mitigation measures (barrier walls), rock excavation, demolition activities, and relocation of existing structures. These costs are discussed on a case-by-case basis for each facility.

6.4 INDIRECT COSTS

A variety of other smaller costs can be expected in conjunction with the installation of wet cooling towers. Individually, no cost element in this category is significant, but the aggregate cost can add 25 percent or more to the project. Costs are generally considered proportional to the overall project cost. Some of these components include, but are not limited to, the following:

- Start-up and commissioning
- Engineering, Procurement, and Construction Management (EPCM)
- Site costs (EPCM consultant)
- Acceptance testing
- Specialized engineering services (e.g., surveying)
- Owner cost
- Permitting

An indirect cost is included for each facility equal to 25 percent of all direct costs.[1] This value is based on previous cost evaluations of similar projects and is considered typical of large capital projects such as a wet cooling tower installation.

6.5 CONDENSER MODIFICATION

As noted above, the incorporation of wet cooling towers will likely require modifications to the existing condenser, in the form of water box reinforcements and tube sheet bracing. Each condenser may require reinforcement of the tube sheet bracing with 6-inch x 1-inch steel, and water box reinforcement/replacement with 5/8-inch carbon steel. A conservative estimate of 5 percent of all direct costs is included to account for possible condenser modifications.

6.6 CONTINGENCY

Cost contingency is an allowance, above and beyond the base costs, that will ensure the successful completion of the project. Contingencies address omissions, accidents, cost overruns, and unexpected obstacles that may arise, and allow for the development of a conservative cost estimate. At existing facilities, interference with underground infrastructure or other facility operations is likely to be a major component of contingency costs. A contingency cost value equal to 25 percent of the sum of all direct and indirect costs is included for this study.[2] This value is based on previous cost evaluations of similar projects and is considered typical of large capital projects such as a wet cooling tower installation.

6.7 OPERATIONS AND MAINTENANCE (NON-ENERGY)

Wet cooling towers require constant maintenance and management to ensure optimal performance, especially in a seawater application (e.g., fouling/clogging of fill materials, corrosive effects of salt water). Routine costs include management and labor, chemical treatment for fouling and corrosion control, and spare parts and replacement costs. Vendors did not provide annual operations and maintenance (O&M) estimates for each project due to the variability of final installation at each site and other project unknowns. O&M estimates were based on data used for previous evaluations, such as the Phase I and II rules (USEPA 2001; 2002a). Adjustments were made to reflect a seawater application based on cooling tower vendor input.

This study used a Year 1 base cost of $4.00 per gallon per minute (gpm) of circulating water flow in the tower. The base cost for Year 12 is increased to $5.80/gpm to reflect replacement costs for major system components that are expected to occur at this point in the project life span. A year-over-year escalator of 2 percent is included as an adjustment for inflation. Detailed O&M costs are presented in Table 5-2.

[1] 30 percent for Diablo Canyon and SONGS.
[2] 30 percent for Diablo Canyon and SONGS.

Table 5-2. Base O&M Costs

Cost element	Base cost years 1–11 ($/gpm)	Base cost years 12–20 ($/gpm)
Management	1.00	1.45
Service and spare parts	1.60	2.32
Fouling / corrosion control	1.40	2.03
O&M total	**4.00**	**5.80**

In most analyses of O&M costs, energy usage is a major component. For this study, increases in energy use associated with wet cooling tower operation are addressed as part of the energy penalty discussion in Section 6.9.

6.8 SHUTDOWN DUE TO CONSTRUCTION AND INTEGRATION

Facilities may experience temporary interruptions of their normal operations during a wet cooling tower's construction and its integration with each generating unit. Tie-in to the existing condenser(s) will require each unit to be offline for some duration, but overall shutdown times are highly site–specific and reflect such things as the existing configuration and annual capacity utilization. Most of California's coastal facilities would not incur any direct economic loss associated with a construction tie-in because they generally operate infrequently and have long periods of inactivity with which the necessary construction could be coordinated. Contractual requirements, such as hot standby, may not be accurately reflected in reported generating output figures.

Downtime estimates were based on previous retrofit projects and engineering estimates prepared for other facilities. Actual connection downtimes for fossil fuel facilities were relatively short, ranging from 83 hours at Jefferies Station (SC) to 30 days for each unit at Canadys Station (SC). Other estimates developed for proposed retrofit projects have reached similar conclusions of approximately one month per unit (Bowline Point (NY) and Roseton Station (NY) (USEPA 2002b). This study conservatively assumed a construction-related shutdown of six weeks for most of the fossil fuel facilities. Of these only Haynes (Unit 8) and Moss Landing (Units 1 & 2) are expected to incur a direct financial loss from construction downtime.

Nuclear plants are considerably more complex than an average fossil facility and would be expected to incur a longer construction shutdown, especially in light of enhanced security measures enacted since 2001 and the necessary involvement of the Nuclear Regulatory Commission in the oversight and approval process. Estimates prepared for Indian Point (NY) and Salem (NJ) ranged from four to seven months per unit in addition to any planned refueling outage (lasting an estimated 40 days). An engineering assessment prepared for PG&E in 1982 estimated an outage time of four months per unit at Diablo Canyon (Tera Corp 1982) while other estimates range as high as 12 months or more (BES 2003). This study estimated a construction-related shutdown of eight months for Diablo Canyon and six months for San Onofre, with the difference largely reflecting different facility configurations and the more compact nature of the Diablo Canyon facility.

The importance of Diablo Canyon and San Onofre to statewide grid reliability (providing approximately 12 percent of California's electrical supply) would suggest the need to stagger retrofits on a unit-by-unit basis to minimize the construction-related downtime at each facility. This approach appears reasonable for San Onofre given the relative locations of Units 1 and 2 to their respective cooling towers and the fact that each unit operates its own distinct cooling water system. Diablo Canyon's configuration does not easily lend itself to a staggered retrofit approach. Because both generating units share a common intake structure and the cooling towers would be located in the same general area, any disruptions to circulating water pumps and transmission pipelines would affect the operation of both units and require both units to be taken offline at the same time.

6.8.1 MERCHANT GENERATORS

Merchant, or third-party, facilities generate electricity for sale to another entity for distribution to retail customers. These generators can enter into short or long-term contracts or sell electricity on the spot market to provide load-following or peaking capacity to the grid. Costs and revenues are driven by the wholesale prices for fuel and electricity, although terms of individual contracts may contain revenue provisions or other obligations not captured in this study. Because facility-specific financial information was not available, construction-related revenue loss estimates are based on wholesale pricing data obtained from public sources.

For merchant generators, lost revenue estimates from shutdown were calculated by first estimating the length of downtime required to complete the installation and comparing this estimate with expected monthly utilization (based on the 2006 output profile). The net loss is calculated using wholesale electricity rates for the appropriate months less the estimated fuel savings from the same period. This calculation is expressed by the following equation:

$$R_d = \sum_n \left(P_w \times MWh\right) - \left[\left(\frac{HR \times F}{1000}\right) \times MWh\right]$$

where:

R_d = revenue loss from construction downtime, in \$

P_w = wholesale electricity price for month n, in \$/MWh[3]

MWh = net generating output for month n, in MWh

HR = average unit heat rate, in BTU/kWh

F = fuel cost for month n, in \$/MMBTU[4]

[3] Weighted average monthly wholesale price, 2006, Intercontinental Exchange for SP15 trading hub (ICE 2006a)

[4] Weighted average monthly wholesale price, 2006, Intercontinental Exchange for Citygate trading hub (ICE 2006b).

6.8.2 INVESTOR- AND PUBLICLY-OWNED UTILITIES

Utility facilities generate electricity and, through their parent companies, sell directly to retail customers. Gross revenues are generally higher, on a per-MWh basis, than merchant generators because they account for transmission and distribution in addition to the cost of generation. Revenue losses resulting from construction downtime are calculated differently because the utility must procure electricity for its customers from other sources at rates higher than its own cost of generation. The two investor-owned utilities in this study, Diablo Canyon and San Onofre, are nuclear-fueled and can recoup some production-related costs during a shutdown. The Los Angeles Department of Water and Power operates three facilities in this study—Harbor, Haynes, and Scattergood—fueled by natural gas and can recoup fuel costs similar to merchant generators.

For San Onofre and Diablo Canyon, lost revenue estimates were calculated by first estimating the length of downtime required to complete the installation and then determining the lowest generating period corresponding to the downtime estimate (based on 2006 net output). The net loss is calculated using the average replacement power cost less the estimated fuel savings that would be recouped during the same period. This calculation is expressed by the following equation:

$$R_d = \left(P_r \times MWh\right) - \left[\left(C_r - F\right) \times MWh\right]$$

where:

R_d = revenue loss from construction downtime, in \$
P_r = annual average retail electricity price, in \$/MWh[5]
MWh = net generating output for entire downtime period, in MWh
C_r = annual average replacement power cost, in \$/MWh[6]
F = fuel cost, in \$/MWh[7]

Specific replacement fuel costs were not available for LADWP. Downtime estimates are calculated using wholesale natural gas prices.

6.9 ENERGY PENALTY

The energy penalty is divided into two components: increased parasitic use resulting from the additional electrical demand of cooling tower fans and pumps; and the decrease in thermal efficiency resulting from elevated turbine backpressure values. Monetizing the energy penalty requires some assumption as to how the facility will choose to alter its operations to compensate for these changes, if at all. One option would be to accept the reduced amount of revenue-generating electricity available and absorb the economic loss ("production loss option"). A second option would be to increase the firing rate to the turbine (i.e., consume more fuel to generate additional heat) and produce the same amount of revenue-generating electricity as had

[5] Utility-specific rates, 2006, US Energy Information Agency database (EIA 2006).
[6] Average annual replacement power cost, 2006, PG&E 2006 Annual Report (PG&E 2006)
[7] US average nuclear fuel cost, 2006, Nuclear Energy Institute (NEI 2006).

been obtained with the once-through cooling system ("increased fuel option"). A more likely option, however, is some combination of the two.

For Diablo Canyon and SONGS, the energy penalty is based on a production loss assumption only. The design and complexity of a pressurized water reactor system make it unlikely that the thermal input to the turbine can be increased within operating guidelines. Thermal input increases may also be limited for combined-cycle units, for which steam generation is an indirect process.

Ultimately, the decision to alter operations to address efficiency changes is driven by considerations unknown to this study (e.g., corporate strategy, contractual obligations, and turbine pressure tolerances). For simplicity, the monetized value of the energy penalty assumes the facility will increase the firing rate to the turbine to compensate for reduced efficiency and generate the amount of electricity equivalent to the once-through system. In general, the increased fuel option is less costly, in nominal dollars, than the production loss option, but may not reflect long-term costs, such as increased maintenance, that may result from the continued high firing of the turbine.

6.9.1 INCREASED PARASITIC USE (FANS)

Depending on ambient conditions or the operating load at a given time, a facility may be able to take one or more cooling tower cells offline and still obtain the required level of cooling. This would also reduce the cumulative electrical demand from the fans. For the purposes of this study, however, operations are evaluated at the design conditions, i.e., maximum load; no allowance is made for seasonal changes.

The fan penalty is expressed as a percentage of the total generating capacity and is calculated using the following equation:

$$F_p = \left(\frac{F_{hp} \times 0.0007457 \, {}^{MW}\!/_{hp}}{G} \right) \times 100$$

where:

F_p = energy penalty from fan power demand, in %
F_{hp} = motor power, in hp
G = generating capacity, in MW

6.9.2 INCREASED PARASITIC USE (PUMPS)

Wet cooling towers require substantial pumping capacity to circulate the large volumes of water through the towers and condensers. The wet cooling system will demand more electrical power than the once-through system it replaces because the configuration and demands are somewhat different. For example, static head values will likely increase due to the height required to reach the top of the tower risers (50 feet or more for many facilities), while friction head loss may increase if the cooling towers must be located far from the condensers they serve, thereby requiring long stretches of supply and return piping.

In most cases, the change in operating demand will require new pumps with different design specifications. Where feasible, some of the existing once-through circulating water pumps will be retained to provide makeup water to the towers. The net pump penalty estimates the power demand of the new configuration versus the existing demand relative to the facility's overall generating capacity.

The pump penalty is expressed as a percentage of the total generating capacity and is calculated using the following equation:

$$P_p = \left(\frac{(P_1 - P_2 + P_3) \times 0.0007457 \ {}^{MW}\!/_{hp}}{G} \right) \times 100$$

where:

P_p = energy penalty from net pump power demand
P_1 = total motor power for cooling tower pumps, in hp
P_2 = total motor power for existing circulating water pumps, in hp
P_3 = total motor power retained from existing circulating water pumps, in hp
G = generating capacity, in MW

6.9.3 EFFICIENCY LOSS—NATURAL GAS FACILITIES

Adjustments to the heat rate were calculated based on the ambient conditions for each month and reflect the estimated difference between operations with once-through and wet cooling tower systems. Using the increased fuel option, the cumulative value of the energy penalty is obtained by first calculating the relative costs of generation ($/MWh) for the once-through and wet cooling systems The cost of generation is based on the relative changes in heat rates and the average monthly wholesale natural gas cost ($/MMBTU) (ICE 2006b). The difference between these two values represents the increased cost, per MWh, that results from a wet cooling tower retrofit. The difference in cost, per month, is applied to the net MWh generated for the particular month, and summed to determine an annual estimate, using the following equation:

$$R = \sum_{n=1}^{12} \left[\left(\frac{HR_{cc} \times F}{1000} \right) - \left(\frac{HR_{ot} \times F}{1000} \right) \right] \times MWh$$

where:

R = annual revenue loss, in $
HR_{cc} = heat rate with closed-cycle cooling for month n, in BTU/kWh
HR_{ot} = heat rate with once-through cooling for month n, in BTU/kWh
F = fuel cost for month n, in $/MMBTU
MWh = net generating output for month n, in MWh

6.9.4 EFFICIENCY LOSS—NUCLEAR FACILITIES

Nuclear facilities do not have the option of increasing the thermal input to the turbine to increase the net output as compensation for decreased efficiency. As investor-owned utilities, PG&E and SCE must purchase electricity from other sources to make up for this shortfall, generally at a higher cost than its normal cost of generation. Efficiency losses were calculated based on the ambient conditions for each month and reflect the estimated difference between operations with once-through and wet cooling tower systems. For each month, the increase in heat rate is translated to a net shortfall, in MWh, that must be purchased from other sources.

The shortfall amount, per month, is summed, and multiplied by the average annual procurement cost to determine an annual estimate calculated using the following equation:

$$R = \sum_{n=1}^{12} \left(\frac{HR_{cc} - HR_{ot}}{HR_{ot}} \right) \times MWh \times C_r$$

where:

R = annual revenue loss, in \$
HR_{cc} = heat rate with closed-cycle cooling for month n, in BTU/kWh
HR_{ot} = heat rate with once-through cooling for month n, in BTU/kWh
MWh = net generating output for month n, in MWh
C_r = annual average replacement power cost, in \$/MWh

6.10 NET PRESENT VALUE/NET PRESENT COST

The net present value (NPV) is an economic valuation tool to estimate the potential for profit or loss associated with a large capital investment over a certain time period. The NPV takes into account all expected annual cash flows, both positive and negative, over the life of the project, applies a discount rate, and sums them to a single value presented in current dollars. It does not represent a cash outlay at the beginning of the project. Ordinarily, the NPV is used to measure the potential for profit, i.e., if the NPV is positive, the investment will earn money over the long term. For this study, it is assumed there is no potential to realize any discernible profit from the investment, so all cash flows will be negative.

Because all cash flows associated with a retrofit are negative and the NPV represents the 20-year cost of the project, in current dollars, this study refers to this valuation as “Net Present Cost,” or NPC, instead of the more common NPV. This term more clearly conveys the idea that wet cooling tower retrofit costs, as described in this study, are expenditures and is calculated in the same manner as the NPV.

The discount rate used in this study (7 percent) is based on federal government guidelines used in developing economic analyses of proposed regulations and is a conservative estimate of the average pre-tax rate of return for private investment (OMB 2007). EPA used the same rate in developing its cost analysis for the Phase II rule (USEPA 2002 EBA). Higher or lower discount rates may be more appropriate for individual facilities but sufficient economic data were not available to conduct the appropriate sensitivity analysis.

This study selected a 20-year amortization period for net present cost and annualized cost calculations based on the expectation that a 20-year lifespan for saltwater cooling towers is a reasonable period before degradation of the original structure becomes significant and incurs higher replacement and repair costs. The 20-year period is not based on a particular unit's projected or anticipated life span. It is noted that many aging facilities may not exist in their current form at the end of this time period.

The NPC is calculated using the following equation:

$$NPC_{20} = \sum_{t=0}^{20} \frac{C_t}{(1+r)^t}$$

where:

NPC_{20} = net present value of all costs incurred over project life span (20 years)
t = project year beginning at $t = 0$
C_t = cost incurred in year t
r = discount rate (7.00 %)

6.11 ANNUAL COST

An annualized cost estimates the constant annual value of financial expenditures and revenue losses due to a particular project over time; this can also be considered a facility's annual cost of compliance. It presents the annual economic impact a facility can expect to sustain due to amortized capital costs, O&M, and the energy penalty.

Annualized capital costs (C_a) are developed according to the following equation:

$$C_a = \left[C_t \times \left(\frac{r \times (1+r)^n}{(1+r)^n - 1} \right) \right] + R_{ep} + OM_a$$

where:

C_a = annualized cost
C_t = total capital cost (direct, indirect, contingency)
r = discount rate (7.00 %)
n = amortization period (20 years)
R_{ep} = annual revenue loss from energy penalty (parasitic load, efficiency loss)
OM_a = annual operations and maintenance cost

Assumptions made for discount rate and amortization period are the same as for the NPC calculation. Shutdown losses are added to the annual cost for Year 0 only.

6.12 COST-TO–GROSS REVENUE COMPARISON

An annualized cost-to-gross revenue comparison further illuminates the financial impact that a cooling system retrofit will have on a particular facility. Ideally, facility-level economic data are used to accurately account for company finances, contractual obligations, and generating costs. These data were not available for this study. Instead, a gross annual revenue estimate is developed based on 2006 net generating output (CEC 2006). For investor-owned utilities, gross revenue estimates are then calculated by applying the average annual retail rate obtained from EIA databases (EIA 2006). For merchant generators, the gross revenue estimate is based on the weighted average monthly wholesale price for the SP 15 trading hub (ICE 2006).

This estimate represents the proportional annual cost to gross, not net, revenues. It does not account for contractual obligations, revenues received from other activities, fixed revenue requirements, operational costs, or any tax savings.

For utility generators, the ratio is calculated by the following equation:

$$GRR = \frac{C_a}{(P_r \times MWh)}$$

where:

GRR = gross revenue ratio
C_a = annualized cost
P_r = annual average retail electricity price, in $/MWh
MWh = 2006 net generating output, in MWh

For merchant generators, the ratio is calculated by the following equation:

$$GRR = \frac{C_a}{\left(\sum_{n=1}^{12}(P_w \times MWh)\right)}$$

where:

GRR = gross revenue ratio
C_a = annualized cost
P_w = wholesale electricity price for month *n*, in $/MWh
MWh = net generating output for month *n*, in MWh

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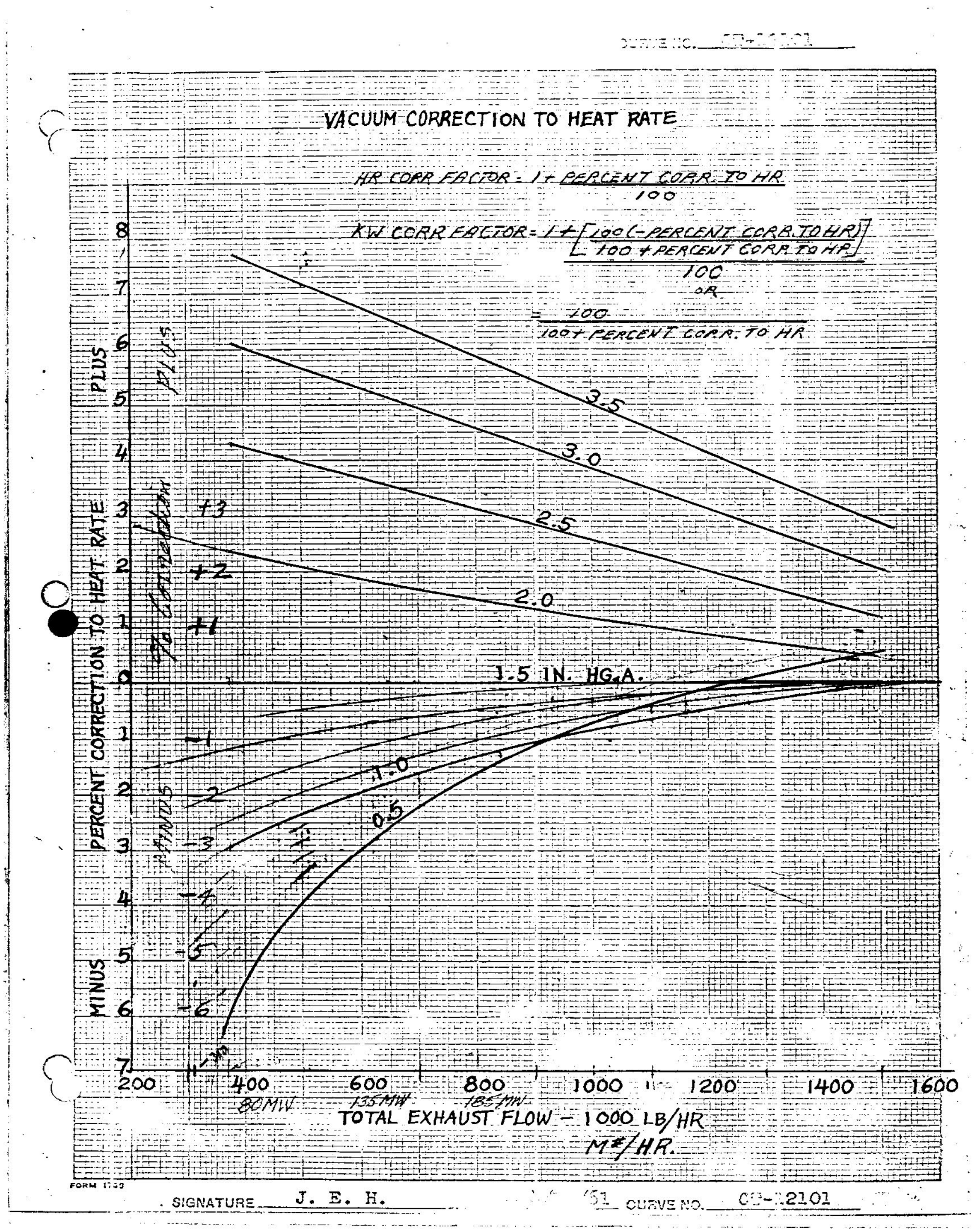
Appendix A. Example Heat Rate Correction Curve



6. Retrofit and Repower Examples

1.0 General Summary

In recent years, alternative cooling methods—particularly wet and dry closed-cycle systems—have increasingly become the preferred approach for new steam electric facilities. The majority of all new conventional steam units constructed in the last two decades have used a closed-cycle system, with nearly all new combined-cycle units adopting this approach.

The economics and engineering considerations of a closed-cycle system are more favorable when part of a new facility's initial construction or a major overhaul. Altering the cooling system at an existing facility increases costs and can adversely impact the performance of the generating units. The decision to retrofit an existing facility from once-through cooling to closed-cycle is usually driven by extenuating circumstances that mandate a conversion, such as regulatory oversight or changes in water availability.

Repowering, on the other hand, is a more comprehensive upgrade or overhaul to the facility's generating system, including the boiler and turbine. When combined with a repowering project, closed-cycle systems become favorable, and may actually be preferable, to continued use of once-through cooling. In some respects, a repowered facility is similar to a new facility in that it has wider latitude in selecting an alternative cooling system.

2.0 Retrofit Examples

Retrofitting an existing once-through cooling system is a feasible alternative provided certain conditions can be met. Conversions, however, have been infrequent at large power plants. In its development of the Phase II rule, EPA identified three facilities that had undergone a closed-cycle retrofit—Jefferies Steam, Palisades Nuclear, and Canadys Station. This study identified three additional facilities—Plant Yates, Wateree, and McDonough—although information was available only for Plant Yates. Conversion of the Unit 7 cooling system at the Pittsburg Power Plant is California has also sometimes been considered a retrofit.

2.1 Jefferies Steam

The Jefferies Steam facility in South Carolina, owned and operated by Santee Cooper, consists of four steam-generating units. The plant was initially constructed in the 1950s with two oil-fired units to augment electric power production from the adjacent Jefferies Hydro facility. In 1970 two additional units, both coal-fired, with a rated capacity of 173 MW each (346 MW total), were added. The oil-fired units (1 and 2) remain available for service during critical periods but are used infrequently because of high fuel oil costs. All four units were initially designed with once-through cooling using water from Lake Moultrie, a constructed impoundment in the Santee Cooper River Basin.

In the 1980s the U.S. Army Corps of Engineers (USACE) determined that the impoundment project had created undesirable effects (principally sedimentation) downstream of the dam and proposed a rediversion project as mitigation. The rediversion canal that was constructed redirects water back to the Santee River, but has the effect of reducing the reliable water supply available to the Jefferies Steam facility. As part of a compensation agreement, the USACE-Charleston District funded the conversion of the Unit 3 and 4 once-through cooling system to a closed-cycle cooling (wet tower) system. The project was completed in 1985 (USEPA 2002).

The Jefferies mechanical draft wet cooling towers are made of concrete with PVC fill and designed with a 10° F approach temperature. New supply and return pipelines were constructed (1,700 feet total distance) using 108-inch reinforced concrete. The facility did not need to modify its existing intake structure and was able to use its existing once-through pumps to circulate water between the towers and condensers. Three new booster pumps were added to account for the increased pump head from the closed-cycle system. The facility also opted to install three new makeup water pumps, each rated at 1,950 gallons per minute (gpm), or 2.8 million gallons per day (mgd). No condenser modifications were required.

Santee Cooper conducted studies evaluating the efficiency penalty caused by the wet cooling towers. The maximum penalty, representing peak demand conditions, was 0.97 of the combined Unit 3 and 4 capacity, with an annual average penalty of 0.16 percent reported for 1988.

Units 3 and 4 retain their ability to use once-through cooling water, although wet cooling towers are the preferred operating mode.

Total cost information was not available for review.

2.2 PALISADES NUCLEAR

Palisades Nuclear plant in Michigan, currently owned and operated by Entergy Corp, is a 730 MW pressurized water reactor facility initially brought online in 1972. As originally designed, the facility used a once-through cooling system with a capacity rating of 486,000 gpm, or 700 mgd. Water was withdrawn from Lake Michigan through a 3,000-foot conduit extending offshore. The offshore intake continues to be used in the current closed-cycle system.

During the licensing proceedings in the early 1970s, citizen and environmental organizations petitioned to limit thermal discharges and radioactive releases from the radwaste system to Lake Michigan. The settlement agreement called for Palisades to convert its existing once-through system to closed-cycle as well as make other modifications to the facility.

Construction of two 18-cell mechanical draft towers began in 1971, with the towers becoming operational in 1974. Towers were designed to operate with the same condenser flow rate as the once-through system (400,000 gpm) and a 30° F cooling range. With the closed-cycle system, cooling water withdrawals initially decreased to 78,000 gpm, or approximately 86 percent. Additional modifications in 1998 further decreased the intake flow to 68,000 gpm, although the facility later obtained approval to increase the withdrawal rate to 100,000 gpm to moderate the impacts on plant efficiency. The net decrease from the original design is approximately 75 percent (USEPA 2004). Because the facility used the original intake structure, intake velocities decreased from 0.5 feet per second (fps) with the once-through system to 0.1 fps after conversion.

The closed-cycle system that came online in 1974 used the existing condenser as it was originally designed for the once-through system. A flaw in the original condenser system, however, led to increased vibrations and leaking during operations. Subsequent to the conversion, all condenser tubes were replaced, although no information is available describing the design changes, if any. New intake pumps were installed to withdraw makeup water from Lake Michigan and to circulate water between the towers and condensers. Dilution pumps were added to the recirculating system to increase the condenser flow to 460,000 gpm.

The facility reported a construction outage of 10 months during the connection and testing of the closed-cycle system because of necessary modifications to the system. Other activities such as condenser flaws and modifications to the radwaste system may have contributed to the outage time, but this cannot be conclusively determined.

The project's reported installed cost was \$18.8 million (\$90 million in 2007 dollars) and included both towers (wood), fill material, drift eliminators, fans, four pumps, new pump houses, circulating water pipes, circulating water treatment system, and other necessary civil engineering and structural projects (e.g., drainage, structure demolition, and relocation) (USEPA 2002). Detailed descriptions of the cost elements were not available and cannot be accurately compared to costs developed in this study.

The facility estimated that the wet cooling towers resulted in 6–8 percent reduction in turbine efficiency compared with the once-through system, with a 20 MW increase in the parasitic load. No data are available to confirm these estimates.

2.3 CANADYS STATION

Canadys Station, located in South Carolina, consists of three coal-fired generating units owned and operated by South Carolina Electric with a rated generating capacity of 500 MW. Brought online in the 1960s, all three units were originally designed with once-through cooling systems drawing water from the Edisto River. Cooling system conversions were completed in two separate projects. The first, for Unit 3, was finished in 1972, with Units 1 and 2 retrofitted two decades later in 1992. Units 1 and 2 share a combined closed-cycle system.

Conversion to wet cooling towers at Canadys was largely driven by the lack of reliable cooling water volumes and possible thermal discharge impacts during low-water periods.

Unit 3, retrofitted in 1972, was initially fitted with a mechanical draft wood tower having a design approach temperature of 6° F. This tower was upgraded to a fiberglass model in 1999. The Unit 1 and 2 tower, constructed in 1992, is made of concrete with a design approach of 7° F. The relative distances between the cooling towers and the unit condensers required new circulating water pumps to handle the increased pump head. These distances (1,700 feet for Units 1 and 2; 650 feet for Unit 3) and the necessary piping likely contributed to a significant increase in capital cost for the projects, although no specific cost data were available for review.

Canadys installed new intake pumps to withdraw makeup water from the Edisto River through the original intake structure. No other significant modifications to the plant were reported. The facility did not modify its condensers for service in a closed-cycle system and has not reported any operational problems (USEPA 2002).

The cooling tower system for Units 1 and 2 was completed in approximately 8 months with a construction-related outage of roughly 30 days. The construction tie-in was scheduled to coincide with maintenance outages that were already planned.

2.4 PLANT YATES

Plant Yates, located in Georgia, is a coal-fired steam facility owned and operated by Georgia Power. The facility is rated at 1,250 MW, with seven generating units. Units 1–5 were brought online in the 1950s with a once-through cooling system that withdraws water from the Chattahoochee River. Units 6 and 7 were originally designed with closed-cycle systems.

The cooling tower constructed as a replacement for the Units 1–5 once-through system consists of 40 mechanical draft cells arranged in a back-to-back configuration. Flow reductions achieved with the tower are estimated to be 96 percent (600 mgd to 22). Costs for the retrofit project were reported at $87 million (Super 2002). Detailed information describing what was included in the reported cost was not available for review.

2.5 PITTSBURG POWER PLANT

The conversion of Pittsburg's Unit 7 cooling system is sometimes categorized as a retrofit in the same manner as the projects described above. Unit 7, brought online in 1972, was originally constructed with an enclosed cooling canal designed to recirculate cooling water from the condenser. Heat was rejected in the 6,000-foot-long canal through natural circulation and spray heads. The original canal did not provide sufficient cooling to allow Unit 7 to operate efficiently and was augmented with two mechanical draft wet cooling towers in 1976.

The new towers (crossflow design) were located on a backfilled portion of the center strip that divides the canal. Each tower consists of 13 cells.

Total project costs were reported as $48 million (2007 dollars). Incorporating cooling towers with the existing cooling canal enabled the facility to use much of the same infrastructure already in place (pipes, pumps).

No performance data were available for review.

3.0 REPOWER PROJECTS

Repower projects, as noted above, are more comprehensive in their modifications to the existing facility and often involve the complete demolition and replacement of an existing facility. In doing so, closed-cycle cooling options, particularly dry cooling, become more practical alternatives.

In California, five of the 21 coastal power plants have proposed repowering projects that eliminate the use of once-through cooling water, either in whole or in part—South Bay, Humboldt Bay, Contra Costa (Gateway), El Segundo, and Encina.

3.1 SOUTH BAY REPLACEMENT PROJECT

South Bay Power Plant (SBPP), in Chula Vista, is owned by the San Diego Unified Port District and operated by LSP South Bay, LLC (LSP). LSP has proposed to replace the existing facility with the South Bay Replacement Project (SBRP).[1] The existing SBPP consists of five generating units ranging from 35 to 45 years old and operated under a reliably must run (RMR) contract with the California Independent System Operator (ISO). The SBRB will provide sufficient replacement power for the existing facility, thereby allowing the removal of the RMR status and the demolition of the existing units. Four of the five generating units are natural gas–fired steam turbines (Units 1–4), while the remaining unit (GT-1) is a combustion turbine powered by fuel oil #5. Details on the existing operating units are presented in Table 6–1.

Table 6–1. Current South Bay Power Plant

Unit #	Type	Rated capacity (MW)	Existing flow (gpm)
Unit 1	Steam turbine	152	78,000
Unit 2	Steam turbine	156	78,000
Unit 3	Steam turbine	183	124,600
Unit 4	Steam turbine	232	136,800
GT-1	Gas turbine	15	--
Total		**738**	**417,400**

Cooling water for Units 1–4 is withdrawn from the southern end of San Diego Bay at a maximum rate of 602 mgd. Water withdrawals from and discharges to the bay are permitted under NPDES Permit CA0001368 as administered by the San Diego Regional Water Quality Control Board. The facility discharges elevated-temperature wastes to the bay along with low-volume wastes generated at the site.

[1] LSP South Bay, LLC withdrew its Application for Certification on October 22, 2007 following publication of the Administrative Draft.

3.1.1 PROJECT DESCRIPTION

The SBRP is designed to provide sufficient reliability to eliminate the RMR status of the SBPP. The new plant will consist of two natural gas–fired combustion turbines (General Electric 7FA), a heat recovery steam generator (HRSG), and a steam turbine, with a combined rating of 500 MW at 62° F. The new combined-cycle system is designed to operate at a heat rate of 6,993 BTU/kWh compared with the 10–12,000 BTU/kWh heat rates of the current steam units. This enables the SBRP to reduce air emissions on a per-kWh basis compared with the existing facility.

The HRSGs will be capable of duct firing, although duct firing increases the operating heat rate. With duct firing, the steam turbine's output would boost the plant's generation capacity to 620 MW, although duct firing is not planned to be used frequently.

A selective catalytic reduction (SCR) module will be attached to each combustion turbine's exhaust system to reduce air emissions. The SCR system will use ammonia vapor in the presence of a catalyst to reduce the NO_x in exhaust gases. The system will employ aqueous ammonia, which will be injected into the exhaust gas upstream of the catalyst. An oxidation catalyst will also be used to reduce the concentration of CO.

The existing facility exceeds the threshold defining a major facility under the prevention of significant deterioration (PSD) program. Since the SBRP would also exceed the threshold, the facility will remain a major facility after repowering. The change in air emissions with the repowering project, however, is less than the threshold at which it would be considered a major *modification*. Therefore, the SBRP would not have to undergo a review under the PSD regulatory program. The projected differences in air emissions between the existing facility and the SBRP are summarized in Table 6–2.

Table 6–2. SBRP and SBPP Air Emission Comparison

Pollutant	Existing SBPP baseline emissions (tons/year)	Maximum annual SBRP emissions (tons/year)	Net increase (decrease) in emissions (tons/year)
NO_2	106.5	104	(2.5)
SO_2	6.9	11	4.1
CO	763.5	544.6	(218.9)
PM_{10}	69.3	69.2	(0.1)

The SBRP will be located on 12.9 acres adjacent to the SBPP in what is referred to as the "former LNG site." Construction activities will include a new electrical system interconnection facility on 6.5 acres within the former LNG site. Natural gas will be provided to the facility in a new 16-inch pipeline connected to the current SBPP support infrastructure. The project area's zoning designation is General Industrial (I), which encourages industrial developments. The site is included within the Energy/Utility Zone as defined in the Chula Vista Bay Front Plan; an environmental impact report (EIR) will be prepared for the plan to meet California Environmental Quality Act (CEQA) requirements. Noise generated by SBRP's operations will be less than that generated from the current facility. Noise will be controlled by structural methods and equipment selection.

In terms of visual resources, the new facility will have a smaller footprint and a lower profile once demolition of SBPP has been completed. The boiler structures at the SBPP are 160 and 180 feet tall. SBRP's air cooled condenser (ACC) and exhaust stacks would be 94 and 125 feet tall, respectively. The preliminary assessment indicates that the new facility would be architecturally screened, resulting in less blockage of coastal views from the surrounding areas as well as a reduction in the contrast against the San Diego skyline to the north and mountains to the east. The visibility of the water vapor emissions would also be reduced.

3.1.2 WATER USE

Elimination of water withdrawals from San Diego Bay is one of the driving factors behind the development of the SBRP. Completion of the project and removal of the SBPP will eliminate the withdrawal of up to 602 mgd from the bay.

The steam turbine's cooling system will consist of the ACC system, which uses fin tube bundles grouped into modules and attached to a steel support structure. Steam from the steam turbine will enter the fin tubes as fans within each module force ambient air through the bundles, condensing the steam. Condensate will be collected and pumped back to the boiler feedwater system. In addition to the ACC, a closed-cycle cooling water system will be used to cool auxiliary equipment such as air compressors and bearing coolers. This system will consist of cooling water pumps, an expansion tank, and an air-cooled heat exchanger. Cooling of the heat exchanger will be accomplished similarly to the ACC, using bundles of fin tubes.

All the project's water requirements will be met using potable water sources. The SBRP's water demands result from a combination of boiler makeup supply for the steam cycle and onsite domestic uses. Daily use is projected at 80 gpm. All water will be supplied via the existing 10-inch main connected to the publicly owned Sweetwater Authority. SBRP wastewaters, consisting of sanitary and process wastes, will be discharged to the existing sanitary sewer connection at an approximate rate of 58 gpm.

3.2 HUMBOLDT BAY REPOWER PROJECT

Humboldt Bay Power Plant (HBPP), near Eureka, is operated by Pacific Gas and Electric (PG&E). The existing facility consists of four generating units. Units 1 and 2 are natural gas–fired steam turbine generators (Units 1 and 2) with a combined rating of 105 MW. The remaining two units are 15 MW, diesel-fired mobile emergency power plants (MEPPs). The MEPPS are used as backups when Unit 1 or 2 is offline or during peak winter load periods. HBPP was originally constructed with a nuclear-powered boiling water reactor steam unit (Unit 3), although it has not operated since 1976.

3.2.1 PROJECT DESCRIPTION

The Humboldt Bay Repowering Project (HBRP) replaces the existing facility (Units 1 and 2 plus MEPPs) with a load-following and cycling plant. The repowered facility will consist of 10 natural gas–fired Wartsila dual-fuel reciprocating engine generator sets with a total generating capacity of 163 MW.

Construction of the new units will require the demolition of some of the existing structures at the site. The existing units will remain in operation until the repowering process is complete. Ultimately, the HBRP will utilize some of the existing facilities, including the freshwater supply, natural gas pipeline systems, 60 kV (kilovolt) switchyard and transmission system, and the 115 kV transmission line currently originating from Unit 3. Three separate projects planned for the site include decommissioning of Unit 3; constructing the Independent Spent Fuel Storage Installation; and demolishing the HBPP (demolition of Units 1 and 2 and removal of the MEPPs).

The natural gas fuel requirement for each of the new units is approximately 139 MMBTU/hr. While the generators will mainly be powered by natural gas, they will also have the capability to run on diesel. When burning natural gas, a small amount of pressurized diesel will be injected into the combustion chamber to initiate the combustion cycle. This use of diesel as a pilot fuel would result in the consumption of a maximum of 75 gallons per hour assuming all 10 engines were operating at 100 percent load. Ultra-low sulfur diesel fuel (meeting California Air Resource Board standards) will be used only during emergencies or when gas supplies are curtailed. Curtailment occasionally occurs in winter months when natural gas is required for home heating needs, as required under the California Public Utilities Commission (CPUC) Gas Tariff Rule 14.

A SCR module will be attached to each engine's exhaust system to reduce air emissions. The SCR system will use ammonia vapor in the presence of a catalyst to reduce the NO_x in exhaust gases. The system will employ aqueous ammonia, which will be injected into the exhaust gas upstream of the catalyst. An oxidation catalyst will also be used to reduce the concentration of CO and VOCs.

Table 6–3 compares emissions from the HBRP with the existing facility. The emissions estimates in the table reflect the evaluation conducted for federal PSD and CEQA purposes. The numbers used for that analysis represent the maximum possible emissions, as opposed to emission rates that would be expected under normal operating conditions.

Table 6–3. HBPP and HBRP Air Emission Comparison

		Emissions (tons/year)				
		NO_x	**SO_2**	**CO**	**ROC**	**PM_{10}**
HBPP (Existing)	Unit 1	447.4	0.8	50.4	11.0	9.6
	Unit 2	404.6	0.8	51.5	11.2	9.8
	MEPP 2	17.3	1.1	2.1	0.5	2.6
	MEPP 3	23.4	1.2	2.4	0.6	3.0
	Total	**892.7**	**3.9**	**106.3**	**23.3**	**25**
HBRP (Planned)	Reciprocating engines	263.1	4.7	181.2	198.9	182.8
	Back start generator	0.4	<0.1	0.1	<0.1	<0.1
	Fire pump engine	0.2	<0.1	<0.1	<0.1	<0.1
	Total	**263.7**	**4.7**	**181.3**	**198.9**	**182.8**
	Net Increase (Reduction)	**(629.0)**	**0.8**	**75**	**175.6**	**157.8**

Repowering HBPP results in a large reduction of NO_x emissions, although emissions of SO_2, CO, ROC, and PM_{10} will increase. The Issues Identification Report for the HBRP identifies air quality as a potential issue, citing $PM_{2.5}$ reductions under the National Ambient Air Quality Standards (NAAQS). For reasons beyond the operator's control, natural gas shortages could cause the facility to burn diesel fuel for longer periods of time than considered in the modeling exercises submitted with the application for certification.

Noise is generated from various sources at the existing facility. Likewise, noise would be generated from a number of sources at the repowered facility, including combustion air inlets, transformers, pump motors, and fans. The existing facility is operating within Humboldt County zoning ordinances that address industrial noises. Based on information from vendors and suppliers, noises emanating from the repowered facility are expected to conform to local requirements (an industrial project should not raise the ambient noise by more than 5 decibels [dBA]).

3.2.2 WATER USE

The Wartsila engines used in the HBRP will be cooled with a closed-loop radiator system where cooling water circulates through tube bundles equipped with fins to radiate heat. Air circulation around the tubes will be assisted by fans. Propylene glycol will be added to the cooling water to improve heat transfer. The coolant system will be filled and maintained through separate maintenance tanks that allow recycling without the need for a discharge.

Once-through cooling water withdrawals from Humboldt Bay will be eliminated. The new generating engines, which reject heat through convection and radiation, reduce the facility's water demand from more than 40,000 gallons per minute (gpm) to approximately 1.67 gpm. Average annual discharge rates from HBRP would be less than 1 gpm (0.17 gpm closed loop engine cooling system; 0.32 gpm service use; 0.11 gpm domestic wastewater). Discharges of process and domestic wastewater will be to the local sanitary sewer system. Domestic water supply will be provided by the Humboldt Community Services District. Process water will be supplied via an existing well.

3.3 GATEWAY GENERATING STATION (CONTRA COSTA UNIT 8)

In 2001, the California Energy Commission (CEC) approved the application for certification (AFC) for the Contra Costa Power Plant (CCPP) Unit 8 project owned and operated by Mirant Delta, LLC. Construction began on the unit, although it was never completed. In late 2006, PG&E became the sole owner of CCPP Unit 8, renamed the project the Gateway Generating Station (GGS), and modified the system design. A comparison of the Unit 8 project as proposed by Mirant Delta and the current GGS project is summarized below.

The current facility consists of three retired units (Units 1, 2, and 3) and four operational units (Units 4, 5, 6, and 7). All the operational units are conventional natural gas–fired steam-generating units that use once-through cooling water from the San Joaquin River. Units 4 and 5 are used only as synchronous condensers and do not produce power for sale. Units 6 and 7 have a combined generating capacity of 680 MW. CCPP’s existing National Pollutant Discharge Elimination System (NPDES) permit authorizes the withdrawal of up to 340 mgd of cooling water for Units 6 and 7. As approved, CCPP Unit 8 would have added an additional 530 MW of generating capacity to the existing CCPP complex.

CCPP Unit 8 would have used two natural gas–fired combustion turbine generators, HRSG, and steam turbine, with cooling provided by a 10-cell mechanical draft wet cooling tower. Cooling tower makeup water would have been withdrawn from the existing discharge canal used by Units 6 and 7; no new water would be withdrawn from the San Joaquin River unless Units 6 and 7 were not operational.

The GGS proposes to make use of the same power generation system—two natural gas–fired combustion turbine generators, HRSG, and steam turbine. The approved cooling system uses an ACC instead of the wet cooling tower, with makeup water supplied through the city of Antioch or another purveyor. The use of the ACC will eliminate the need for the 10-cell wet cooling tower and surface condenser. Compared with the Unit 8 project, GGS reduces the makeup water demand from approximately 8,300 gpm to 153.9 gpm. This is not a direct reduction of once-through cooling water withdrawals because the Unit 8 project would have recycled discharges from Units 6 and 7 when they were operational. The 80.9 million gallons per year water demand for the GGS will be provided by the city of Antioch or another supplier.

CCPP Unit 8 also included evaporative cooling for the combustion turbine air inlets. The GGS approach will replace evaporative cooling with an electric chiller system. The electric chiller will reduce combustion turbine inlet air temperatures to 50° F by drawing air across cooling coils containing water chilled with R134A refrigerant.

This system is separate from the ACC used for steam condensate cooling and will consist of a fin fan heat exchanger combined with either a small, wet surface air-cooled heat exchanger system or an evaporative precooler. The wet surface air cooler uses water sprayed over heat transfer bundles to increase cooling capacity through evaporation.

Air quality would be improved slightly, with lower $PM_{10}/PM_{2.5}$ emissions projected from the elimination of the cooling tower and addition of the wet surface air-cooled heat exchanger unit. The modeled emissions are presented in Table 6–4.

Table 6–4. GGS and CCPP Unit 8 Modeled Emissions

Operational source	NO_x	SO_x	CO	POC	$PM_{10}/PM_{2.5}$
GGS maximum annual emissions	174.3	48.5	259.1	46.6	105.4
CCPP Unit 8 maximum annual emissions	174.3	48.5	259.1	46.6	112.2
Change in maximum annual emissions	**0**	**0**	**0**	**0**	**(6.8)**

3.4 EL SEGUNDO

The El Segundo Generating Station is located on a 32.8 acre site in El Segundo, California and has been operating as an electric generating station since May 1955. The power plant consists of 4 utility boilers, and associated steam turbines and generators, fired with natural gas and/or refinery gas, although each unit can be fired with fuel oil, if necessary. Current operation uses ocean water for once-through cooling purposes.

The El Segundo Power Redevelopment (ESPR) Project proposes new generating capacity from 2 power block arrangements, each including a gas turbine generator (GTG), a HRSG, and a back pressure steam generator with an ACC for heat rejection. One power block will be designated as Units 5 and 6, and the second as Units 7 and 8. Units 1 and 2 will be demolished and removed from the site and Units 3 and 4 will remain in operation, resulting in a total plant nominal gross generating capacity of the 573 MW. As ACCs will be used for turbine exhaust heat rejection on the new generating units only Units 3 and 4 will use ocean water for once-through cooling.

Water will be supplied to the ESPR Project from two sources: potable water from the Metropolitan Water District of Southern California and reclaimed wastewater from the West Basin Municipal Water District. Potable water will be used for domestic purposes and fire emergencies, whereas reclaimed wastewater will be used as makeup to the steam cycle following additional on-site treatment, and for other generating needs. Process wastewaters from Units 5 – 8 will be recycled, to the maximum extent practical, back to a reclaimed wastewater supply/storage tank to be reprocessed for high purity steam cycle makeup or as makeup for evaporative coolers. No process wastewaters from these units will be discharged from the facility to surface waters. No changes are planned for the management of plant wastes from Units 3 and 4, i.e., these waste streams will be conveyed to an existing retention basin and ultimately discharged through Outfall 002.

Proposed GTGs are a "fast start" technology, which allows the GTGs to reach their optimum air emissions performance operating levels faster, thereby reducing start up emissions. In addition HRSGs will be equipped with SCRs for NOx control and an oxidation catalyst for CO control.

3.5 ENCINA

The Encina Power Station is located on a 95-acre parcel along the southern shore of the Agua Hedionda Lagoon in the City of Carlsbad. The station is a gas fired generating plant with 5 steam turbines (Units 1 – 5), which currently take once-through cooling water from the lagoon. Units 1 – 3 began operation in the 1950s; a small gas turbine generator was also installed in 1968; Unit 4 began operation in 1973; and Unit 5 began operation in 1978, providing a net generating capacity of 966 MW.

The proposed repowering project will include retirement of Units 1, 2, and 3 and construction of two new generating units (Units 6 and 7) to be placed on 30 acres in the northeast portion of the existing facility, between a rail line and Interstate 5, where 3 fuel oil tanks are being removed. Proposed new construction will include a 558 MW combined cycle generating facility using 2 natural gas fired combustion turbine generators (CTGs), 2 HRSGs, and 2 steam turbine generators (STGs), which will connect to switchyards serving the existing power plant. Units 4 and 5 will remain in operation, and with Units 6 and 7, will be known as the Carlsbad Energy Center

The project site is located in an area designated as nonattainment for State and federal air quality standards for ozone, and for PM_{10} and $PM_{2.5}$. Potential impacts to air quality from the repowering project will be mitigated with the installation and operation of Best Available Control Technology (BACT) on the new gas turbines. Retirement of existing Units 1, 2, and 3 will also be used to offset any new emissions.

Water requirements for new generating capacity at the Energy Center will be met by use of reclaimed wastewater supplied by the City of Carlsbad's Water Recycling Facility and potable water also supplied by the City. Approximately 112 acre feet per year of reclaimed wastewater, with maximum possible usage projected at 517 acre feet, will be used for process operations, cooling, on-site irrigation, and miscellaneous water requirements, thereby conserving higher quality local groundwater for other uses. The new generating units will be air cooled, thereby significantly reducing use of ocean water at the facility for once-through cooling. Potable water will be used for domestic purposes, fire protection, and as a backup to the reclaimed wastewater supply. A 3,600 foot reclaimed wastewater pipeline will be installed between the Energy Center and an existing reclaimed wastewater pipeline at Cannon Road and Avenida Encinas. High purity steam cycle make up water will be produced by further treatment of reclaimed wastewater using reverse osmosis and ion exchange technology at the Energy Center.

4.0 REFERENCES

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A. ALAMITOS GENERATING STATION

AES ALAMITOS, LLC—LONG BEACH, CA

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1.0 GENERAL SUMMARY

Retrofitting the existing once-through cooling system at Alamitos Generating Station (AGS) with closed-cycle wet cooling towers is technically and logistically feasible based on this study's design criteria, and will reduce cooling water withdrawals from Los Cerritos Channel by approximately 95 percent. Impingement and entrainment impacts would be reduced by a similar proportion.

The preferred option selected for AGS includes 3 conventional wet cooling towers (without plume abatement), with individual cells arranged in a back-to-back configuration to accommodate limited space at the site. This option assumes the availability of adjoining property currently owned by Pacific Energy to site one of the cooling towers (for Units 1 and 2). Space limitations would appear to preclude plume-abated towers in the design if they were required to mitigate visual impacts. Initial capital costs for the towers would also increase by a factor of 2 or 3.

Construction-related shutdowns are estimated to take approximately 4 weeks per unit (concurrent), although AGS is not expected to incur any financial loss as a result based on 2006 capacity utilization rates for all units.

The cooling tower configuration designed under the preferred option complies with all identified local use restrictions and includes necessary mitigation measures, where applicable.

1.1 COST

Initial capital and net present costs associated with the installation and operation of wet cooling towers at AGS are summarized in Table A–1. Annualized costs based on 20-year average values for the various cost elements are summarized in Table A–2.

Table A–1. Cumulative Cost Summary

Cost category	Cost ($)	Cost per MWh (rated capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Total capital and start-up [a]	209,800,000	12.28	125
NPC_{20} [b]	263,100,000	15.40	157

[a] Includes all costs associated with the cooling tower construction and installation and shutdown loss, if any.
[b] NPC_{20} includes all capital costs, operation and maintenance costs, and energy penalty costs over 20 years discounted at 7 percent.

Table A–2. Annual Cost Summary

Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Capital and start-up	19,800,000	1.16	11.81
Operations and maintenance	2,100,000	0.12	1.25
Energy penalty	3,500,000	0.20	2.09
Total AGS annual cost	**25,400,000**	**1.48**	**15.15**

1.2 ENVIRONMENTAL

Environmental changes associated with a cooling tower retrofit for AGS are summarized in Table A–3 and discussed further in Section 3.4.

Table A–3. Environmental Summary

		Units 1 & 2	Units 3 & 4	Units 5 & 6
Water use	Design intake volume (gpm)	137,000	259,000	404,200
	Cooling tower makeup water (gpm)	8,200	13,600	17,800
	Reduction from capacity (%)	94	95	96
Energy efficiency [a]	Summer heat rate increase (%)	1.69	1.73	1.67
	Summer energy penalty (%)	2.69	2.62	2.61
	Annual heat rate increase (%)	1.39	1.45	1.35
	Annual energy penalty (%)	2.38	2.35	2.29
Direct air emissions [b]	PM10 emissions (tons/yr) (maximum capacity)	79	149	233
	PM10 emissions (tons/yr) (2006 capacity utilization)	2.4	19	24

[a] Reflects the comparative increase between once-through and wet cooling systems, but does not account for any operational changes to address the change in efficiency, such as increased fuel consumption (see Section 4.6).
[b] Reflects emissions from the cooling tower only; does not include any increase in stack emissions.

1.3 OTHER POTENTIAL FACTORS

Considerations outside this study's scope may limit the practicality or overall feasibility of a wet cooling tower retrofit at AGS.

Available space for wet cooling towers may be problematic if land currently owned by Pacific Energy cannot be secured for use. The analysis in this chapter assumes the land, currently unoccupied and zoned for industrial use, can be obtained, which enables the only reasonable tower configuration that accommodates all six operating units. If this land is not available, a revised analysis would likely be able to accommodate only four units, with Units 1 & 2, as the oldest and least efficient, the most likely to be left out of a retrofit project. The Unit 5 & 6 cooling tower would be relocated to the north and occupy a narrow strip of land alongside the San Gabriel River.

AGS may also face wastewater discharge permit conflicts upon converting to wet cooling towers. The current source water (Los Cerritos Channel) has shown elevated concentrations of some pollutants that would become concentrated in a wet cooling tower. If cooling tower makeup water is obtained from the same source, compliance with effluent limitations may become more difficult. In addition, the facility's receiving water has been reclassified from an ocean to an estuary, which may result in more stringent limitations than those currently applicable. These potential conflicts may be mitigated or eliminated through the use of reclaimed water as the makeup source.

2.0 BACKGROUND

AGS is a natural gas-fired steam electric generating facility located in the city of Long Beach, Los Angeles County, owned and operated by AES Alamitos, LLC. AGS currently operates six conventional steam turbine units (Units 1-6) with a combined generating capacity of 1,950 MW. The facility occupies approximately 120 acres of a 230-acre industrial site along the west bank of the San Gabriel River, two miles northeast of the entrance to Alamitos Bay and the Long Beach Marina. The property's western edge is bordered by the Los Cerritos Channel and North Studebaker Avenue. State Highway 22 borders the northern edge of the property and Westminster Avenue/East 2nd Street borders the south. The Los Angeles Department of Water and Power's (LADWP) Haynes Generating Station (HnGS) is located directly opposite AGS on the east bank of the San Gabriel River (Table A–4 and Figure A–1).

Table A–4. General Information

Unit	In-service year	Rated capacity (MW)	2006 capacity utilization [a]	Condenser cooling water flow (gpm)
Unit 1	1956	175	3.3%	68,500
Unit 2	1957	175	2.7%	68,500
Unit 3	1961	320	17.1%	129,500
Unit 4	1962	320	7.9%	129,500
Unit 5	1969	480	9.3%	202,100
Unit 6	1966	480	11.3%	202,100
AGS total		**1,950**	**9.70%**	**800,200**

[a] Quarterly Fuel and Energy Report—2006 (CEC 2006).

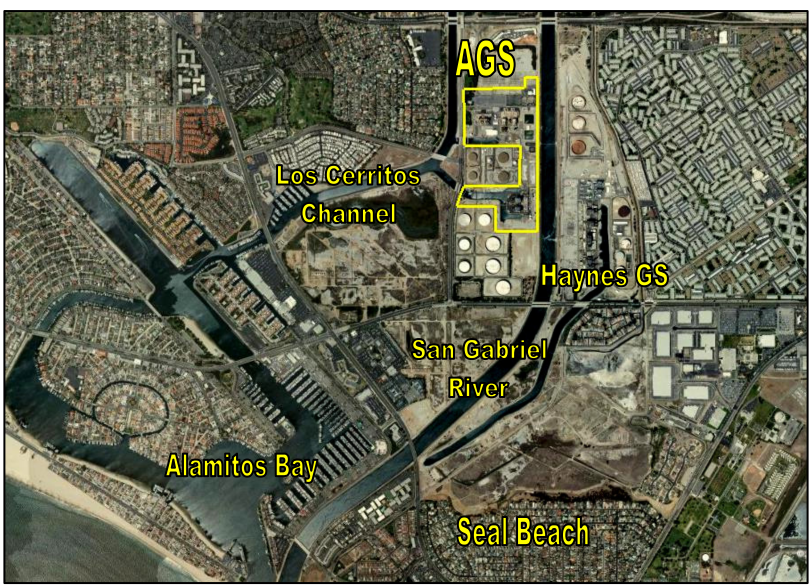

Figure A–1. General Vicinity of Alamitos Generating Station

2.1 COOLING WATER SYSTEM

AGS operates two separate cooling water intake structures (CWIS) to provide condenser cooling water to each of the six generating units (Figure A–2).[1] Two man-made canals draw water from Los Cerritos Channel to the generating units. Units 1 through 4 are served by the north canal, while Unit 5 and Unit 6 are served by the south canal. Once-through cooling water is combined with low-volume wastes generated by AGS and discharged through one of three outfalls to the San Gabriel River. Surface water withdrawals and discharges are regulated by NPDES Permit CA0001139 as implemented by Los Angeles Regional Water Quality Control Board (LARWQCB) Order 00-082.[2]

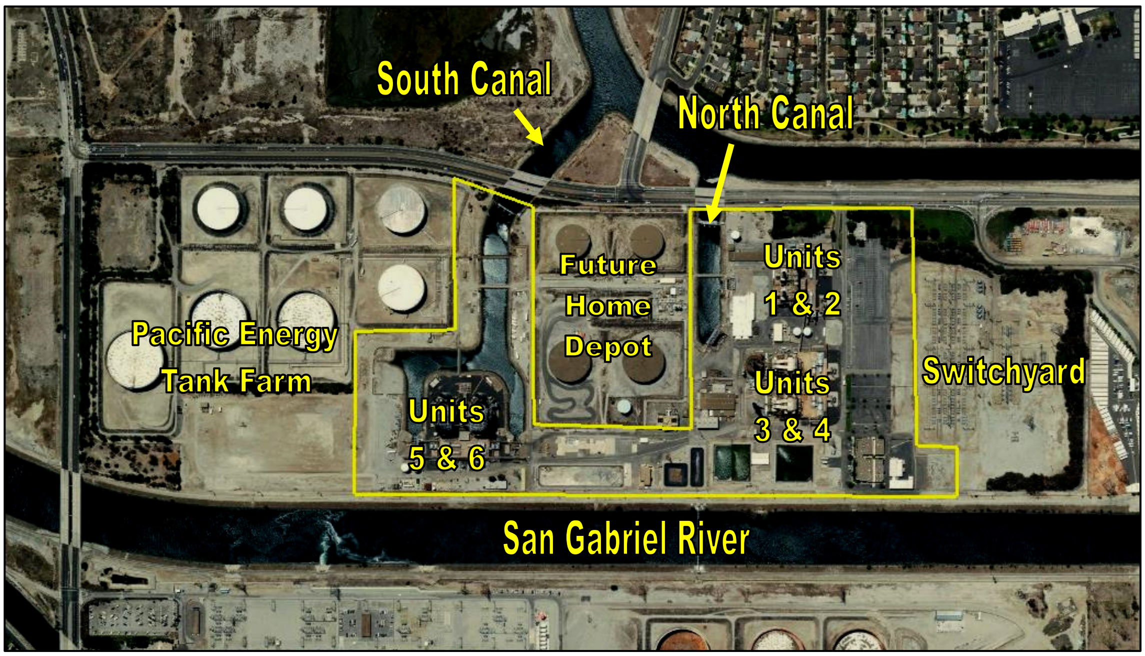

Figure A–2. Site View

The screen house for Units 1 and 2 contains four separate traveling screens (2 per unit) to remove large debris from the intake stream. The wire mesh panels have openings 0.5 by 0.75 inches, leading to a total through screen area of approximately 68 percent. Through-screen velocities for these screens are roughly 4.4 feet per second (fps). Screens are normally rotated and cleaned based on the pressure differential (8 inches) between the upstream and downstream faces of the screens. A high pressure spray removes any debris from the screens, including impinged fish, for disposal at a landfill. Downstream of each screen is a circulating water pump rated at 36,000

[1] The definition of a CWIS is taken from 40 CFR 125.93, which defines a CWIS as “the total physical structure and any associated constructed waterways used to withdraw cooling water from waters of the U.S. The cooling water intake structure extends from the point at which water is withdrawn from the surface water source up to, and including, the intake pumps.” Past definitions of CWIS have often centered on the number of intake bays. The current NPDES permit for AGS alternately identifies three or four CWIS.

[2] LARWQCB Order #00-082 expired on May 10, 2005 but has been administratively extended pending adoption of a renewed order.

gallons per minute (gpm), for a total capacity of 144,000 gpm, or 207 million gallons per day (mgd) (AES 2005).

The configuration for Units 3 and 4 is essentially similar to Units 1 and 2, with the screen houses located approximately 200 feet to the east. Through-screen velocities are roughly 5.4 fps due to the larger capacity pumps that serve the units. Screens are normally rotated and cleaned based on the pressure differential (8 inches) between the upstream and downstream faces of the screens. A high pressure spray removes any debris from the screens, including impinged fish, for disposal at a landfill. Downstream of each screen is a circulating water pump rated at 68,000 gpm, for a total capacity of 272,000 gpm, or 392 mgd (AES 2005).

The intake structure for Units 5 and 6 (south canal) divides to two separate screen houses, one for Unit 5 and one for Unit 6. Each screen house contains two traveling screens to remove large debris from the intake stream. The wire mesh panels have openings 0.625 by 0.625 inches. Through-screen velocities for these screens are roughly 2.2 fps. Screens are normally rotated and cleaned based on the pressure differential (9 inches) between the upstream and downstream faces of the screens. A high pressure spray removes any debris from the screens, including impinged fish, for disposal at a landfill. Downstream of each screen is a circulating water pump rated at 117,000 gpm for a total capacity of 468,000 gpm, or 674 mgd. These pumps are mixed-flow, and can be operated as low as 65 percent of their rated maximum capacity (AES 2005).

At maximum capacity, AGS maintains a total pumping capacity rated at 1,273 mgd, with a total condenser flow rating of 1,152 mgd. On an annual basis, AGS withdraws substantially less than its design capacity due to its low generating capacity utilization (9.7 percent for 2006). On a daily basis during peak demand periods, however, intake flows may approach the design rate. When in operation and generating the maximum load, AGS can be expected to withdraw water from Los Cerritos Channel at a rate approaching its maximum capacity.

2.2 SECTION 316(B) PERMIT COMPLIANCE

None of the CWIS currently in operation at AGS use technologies generally considered to be effective at reducing impingement mortality and/or entrainment. LARWQCB Order 00-082, adopted in 2000, states that “the design, construction and operation of the intake structures [at AGS] represents Best Available Technology (BAT) [sic] as required by Section 316(b) of the Clean Water Act” (LARWQCB 2000. Finding 17). The order does not contain any numeric or narrative limitations regarding impingement or entrainment resulting from CWIS operation, but does require semi-annual monitoring of impingement at each intake structure (coinciding with scheduled heat treatments). Based on the record available for review, AGS has been compliant with this permit requirement.

The LARWQCB has notified AGS of its intent to revisit requirements under CWA section 316(b), including a determination of BTA for minimization of adverse environmental impact, during the current re-permitting process. A final decision regarding any section 316(b)-related requirements has not been made as of this study’s publication.

3.0 WET COOLING SYSTEM RETROFIT

3.1 OVERVIEW

This study evaluates the use of saltwater wet cooling towers at AGS, with the current source water (Los Cerritos Channel) continuing to provide makeup water to the facility. Converting the existing once-through cooling system to wet cooling towers will reduce the facility's current intake capacity by approximately 95 percent; rates of impingement and entrainment will decline by a similar proportion. Use of reclaimed water was considered for AGS but not analyzed in detail because the available volume cannot serve as a replacement for once-through cooling water. The proximity of available sources, however, may make reclaimed water an attractive alternative as makeup water for a wet cooling tower system when considering additional benefits its use may provide, such as avoidance of conflicts with effluent limitations or air emission standards.

The wet cooling towers' configuration—their size, arrangement, and location—was based on best professional judgment (BPJ) using the criteria outlined in Chapter 5 and designed to meet the performance benchmarks in the most cost-effective manner. Information not available to this study that offers a more complete facility characterization may lead to different conclusions regarding the cooling towers' physical configuration.

This study developed a conceptual design of wet cooling towers sufficient to meet the cooling demand for each active generating unit at AGS at its rated output during peak climate conditions. Cost estimates are based on vendor quotes developed using the available information and the various design constraints identified at AGS.

The overall practicality of retrofitting the six units at AGS will require an evaluation of factors outside the scope of this study, such as each unit's age and efficiency and its role in the overall reliability of electricity production and transmission in California, particularly the Los Angeles region.

3.2 DESIGN BASIS

3.2.1 CONDENSER SPECIFICATIONS

For this study, the wet cooling tower conceptual design selected for AGS is based on the assumption that the condenser flow rate and thermal load to each will remain unchanged from the current system. Although no provision is included to re-optimize the condenser performance for service with a cooling tower, some modifications to the condenser (tube sheet and water box reinforcement) may be necessary to handle the increased water pressures that will result from the increased total pump head required to raise water to the cooling tower riser elevation.[3] The practicality and difficulty of these modifications are dependent on the age and configuration of

[3] In this context, re-optimization refers to a comprehensive overhaul of the condenser, such as re-tubing or converting the flow from single to multiple passes. Modifications are generally limited to reinforcement measures to enable the condenser to withstand the increased pressures.

each unit, but are assumed to be feasible at AGS. Condenser water boxes for all six units are located at grade level and appear to be readily accessible. Additional costs associated with condenser modifications are included in the discussion of capital expenditures (Section 4.3).

Information provided by AGS was largely used as the basis for the cooling tower design. In some cases, the data were incomplete or conflicted with values obtained from other sources. Where possible, questionable values were verified or corrected using other known information about the condenser.

For example, the condenser specification sheet for Units 1 and 2 reports a design turbine exhaust pressure of 1.69 in. HgA, with a steam condensate temperature of 105.2 °F. At this pressure, the steam condensate would be approximately 95.5 °F. On the other hand, if the steam condensate temperature is correct, the corresponding turbine exhaust pressure would be approximately 2.26 in. HgA. A review of other information for the condenser (e.g., tube size and material, water flow, steam load) indicates that the steam condensate temperature is incorrectly reported.

Parameters used in the development of the cooling tower design are summarized in Table A–5. Units grouped together are mirror images of each other and generally share identical design specifications.

Table A–5. Condenser Design Specifications

	Units 1 & 2	Units 3 & 4	Units 5 & 6
Thermal load (MMBTU/hr)	843.9	1407	1835
Surface area (ft^2)	90,000	145,000	207,400
Condenser flow rate (gpm)	68,500	129,500	202,100
Tube material	Al Brass	Al Brass	Cu-Ni (90-10)
Heat transfer coefficient (U_d)	538	541	492
Cleanliness factor	0.85	0.85	0.85
Inlet temperature (°F)	63	63	63
Temperature rise (°F)	24.65	21.74	18.17
Steam condensate temperature (°F)	95.5	91.7	91.7
Turbine exhaust pressure (in. HgA)	1.69	1.5	1.5

3.2.2 AMBIENT ENVIRONMENTAL CONDITIONS

AGS is located in Long Beach, Los Angeles County, approximately two miles inland from the entrance to Alamitos Bay. Cooling water is withdrawn at the surface from Los Cerritos Channel, which empties into the Long Beach Marina. Tidal influences and the operation of AGS's circulating water pumps draw ocean water through the marina to the CWIS. Inlet water temperatures are expected to be comparable with temperatures within the marina. Data provided by AGS detailing monthly inlet temperatures contained gaps for some months when units were not operational. Surface water temperatures used in this analysis were supplemented with monthly average coastal water temperatures as reported in the NOAA *Coastal Water Temperature Guide for Los Angeles* (NOAA 2007).

The wet bulb temperature used in the development of the overall cooling tower design was obtained from American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) publications. Data for the Long Beach area indicate a one percent ambient wet bulb temperature of 71° F (ASHRAE, 2006). An approach temperature of 12° F was selected based on the site configuration and vendor input. At the design wet bulb and approach temperatures, the cooling towers will yield "cold" water at a temperature of 83° F. Monthly maximum wet bulb temperatures used in the development of energy penalty estimates in Section 4.6 were calculated using data obtained from California Irrigation Management Information System (CIMIS) Monitoring Station 174 in Long Beach (CIMIS 2006). Climate data used in this analysis are summarized in Table A–6.

Table A–6. Surface Water and Ambient Wet Bulb Temperatures

	Surface (°F)	Ambient wet bulb (°F)
January	58.2	54.0
February	59.8	56.0
March	62.0	58.0
April	64.5	63.0
May	67.8	66.0
June	70.2	68.0
July	69.1	70.0
August	68.3	71.0
September	67.3	69.0
October	65.4	64.0
November	61.6	58.0
December	58.0	54.0

3.2.3 LOCAL USE RESTRICTIONS

3.2.3.1 NOISE

AGS is located in Noise District 4 according to the City of Long Beach Health and Safety Code. This area is considered an "industrial sanctuary" within the city, although commercial and residential zoning areas are located in close proximity to the site, with some residences no more than 450 feet from the property line. The limit for continual noise in District 4 is 70 dBA. Limits for this district are generally applied at the nearest point of likely nuisance, such as a nearby residential or public recreation area. Residential areas to the west (across North Studebaker Avenue and Los Cerritos Channel) are the most likely to be adversely affected by any elevated noise levels. Discussions with the Noise Control Officer for the City of Long Beach indicated that despite the current noise district designation for AGS, new development in the area would likely be required to meet the daytime noise requirements for District 1 of the code (50 dBA compared with 70 dBA) (Long Beach 2006).

The wet cooling towers' overall design incorporates noise control measures to meet local zoning restrictions. Low noise fans and fan deck barrier walls are included to buffer noise associated with the towers' mechanical operation. In addition, concrete barrier walls will be constructed to minimize the noise associated with water falling through the tower. Barrier walls will be placed between the tower and the potentially affected areas and built to a height of 35 feet.

3.2.3.2 BUILDING HEIGHT

AGS is located within a planned industrial development zone (Southeast Development and Improvement Plan—SEADIP) within the City of Long Beach. Within this zone, structures are limited to a maximum above-grade height of 65 feet (Long Beach 2007). The height of the wet cooling towers designed for AGS, from grade level to the top of the fan deck barrier walls, is 62 feet.

3.2.3.3 PLUME ABATEMENT

Local zoning ordinances do not contain any specific criteria for addressing any impact associated with a wet cooling tower plume. Using the selection criteria for this study, plume abatement measures were not considered for AGS; all towers are a conventional design. The plume from wet cooling towers at AGS is not expected to adversely impact nearby infrastructure; the nearest area of immediate concern is the San Diego Freeway (I-405), located approximately 3/4 mile to the northeast.

Community standards for assessing the visual impact associated with a cooling tower plume cannot be determined within the scope of this study. The proximity of nearby residential and commercial areas, when viewed in the context of CEC siting guidelines, may contribute to the selection of an alternate design if a wet cooling tower retrofit is undertaken at AGS in the future. These guidelines assess the total size and persistence of a visual plume with respect to aesthetic standards for coastal resources.

Significant visual changes resulting from the plume may warrant incorporation of plume abatement measures. The selection of plume abated cooling towers, however, would increase the difficulty of identifying sufficient areas in which to locate such towers at AGS. Plume-abated towers require a larger overall area because they are not typically placed in a back-to-back configuration as are the conventional towers included in this study. Acquisition of adjoining land areas or major reconfiguration of facility structures may provide sufficient space. The additional height required for plume-abated towers (approximately 15–30 feet) would conflict with height restrictions under local zoning ordinances.

Section 3.2.3.5 discusses the available areas at AGS.

3.2.3.4 DRIFT AND PARTICULATE EMISSIONS

Drift elimination measures that are considered best available control technology (BACT) are required for all cooling towers evaluated in this study, regardless of their location. State-of-the-art drift eliminators are included for each cooling tower cell at AGS, with an accepted efficiency of 0.0005 percent. Because cooling tower PM_{10} emissions are a function of the rate of drift, drift eliminators are also considered BACT for PM_{10} emissions from wet cooling towers. This efficiency can be verified by a proper in situ test, which accounts for site-specific climate, water, and operating conditions. Testing based on the Cooling Tower Institute's Isokinetic Drift Test Code is required at initial start-up on only one representative cell of each tower for an approximate cost of $60,000 per test, or approximately $180,000 for all three cooling towers at AGS (CTI 1994). This cost is not itemized in the final analysis and is instead included as part of the indirect cost estimate (Section 4.3).

3.2.3.5 FACILITY CONFIGURATION AND AREA CONSTRAINTS

The site configuration and the relative locations of the six generating units creates several challenges in selecting a location for wet cooling towers at the facility. As shown in Figure A–3, much of the area at AGS not dedicated to the generating units or the intake canals is located along a narrow strip bordering the San Gabriel River. This study assumes the electrical switchyard located on the property's northern edge and the Pacific Energy tank farm to the southwest would both be unavailable for use as locations for cooling towers. Relocation of the switchyard, or replacement with gas insulated switchgear (GIS), coupled with the purchase or lease of the land, would free up a large portion of the area for wet cooling towers and enable alternate configurations.

Additional land area might allow a more favorable cooling tower configuration, which, in turn, would permit shorter individual cells and lower pump and fan capacities. Likewise, demolition of the tank farm and acquisition of the property would make sufficient space available for various arrangements of cooling towers, including plume-abated configurations. Due to the cost and uncertainty of both options, neither was selected for further analysis.

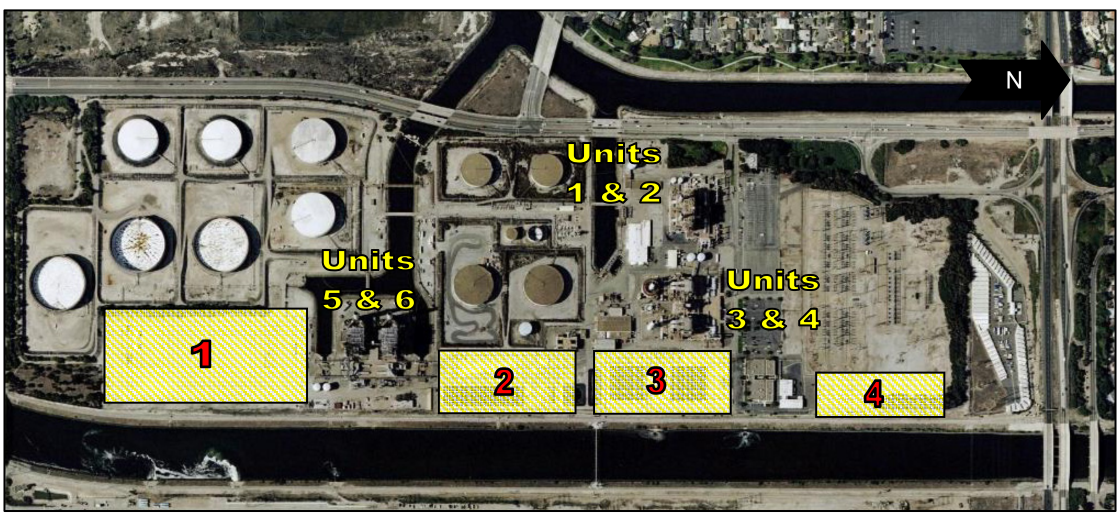

Figure A–3. Cooling Tower Siting Locations

The only sufficiently-sized area that is currently unoccupied is a 450' x 1,000' parcel (Area 1) located to the south of Units 5 & 6 between the tank farm and the San Gabriel River. A smaller parcel (300' x 400') lies immediately east of Units 3 & 4 (Area 3) and is currently occupied by two retention basins used to collect and treat the facility's low-volume wastes. Placement of cooling towers in this area will require the removal of the retention basins and, if necessary, relocation to another area at the site. Cleaning and decommissioning the retention basins may incur costs for hazardous material handling and disposal depending on the nature of wastes treated.

Two smaller areas were considered for cooling tower placement, but ultimately not selected. Area 2 is a narrow strip located north of Units 5 & 6 bordered by the San Gabriel River and the future location of a commercial development to the west. It was not selected due to its proximity to the development site. Area 4 is a narrow section located on the property's northern end bounded by the San Gabriel River and the switchyard. This area does not appear to be wide enough, with sufficient set-back from the river, for a back-to-back cooling tower configuration and concrete noise barrier wall.

Areas 1 and 3 were selected as the most practical locations given the constraints identified. Information not available to this study, such as the presence and configuration of underground infrastructure or future changes to the site or surrounding areas, may make other locations preferable for wet cooling towers.

3.3 CONCEPTUAL DESIGN

Based on the design constraints discussed above, three separate wet cooling towers were selected to replace the current once-through cooling systems at AGS. Each tower will operate independently and be dedicated to each unit pair: Units 1 and 2; Units 3 and 4; and Units 5 and 6. The age, efficiency and design of each unit pair is essentially similar, with both often operating in tandem; thus, a single cooling tower to serve both units is a practical option that minimizes the required space and reduces some material costs. Each tower is configured in a multi-cell, back-to-back arrangement.

3.3.1 SIZE

Each tower is constructed over a concrete collection basin 4 feet deep. The basin is larger than the tower structure's footprint, extending an additional 2 feet in each direction. The concrete used for construction is suitable for saltwater applications. The principal tower material is fiberglass reinforced plastic (FRP), with stainless steel fittings. These materials are more resistant to the higher corrosive effects of saltwater.

The size of each tower is primarily based on the thermal load rejected to the tower by the surface condenser and a 12° F approach to the ambient wet bulb temperature. Flow rates through each condenser remain unchanged.

General characteristics of the wet cooling towers selected for AGS are summarized in Table A–7.

Table A–7. Wet Cooling Tower Design

	Tower 1 (Units 1 & 2)	Tower 2 (Units 3 & 4)	Tower 3 (Units 5 & 6)
Thermal load (MMBTU/hr)	1687.8	2814	3670
Circulating flow (gpm)	137,000	259,000	404,200
Number of cells	10	16	24
Tower type	Mechanical draft	Mechanical draft	Mechanical draft
Flow orientation	Counterflow	Counterflow	Counterflow
Fill type	Modular splash	Modular splash	Modular splash
Arrangement	Back-to-back	Back-to-back	Back-to-back
Primary tower material	FRP	FRP	FRP
Tower dimensions (l x w x h) (ft)	270 x 108 x 62	432 x 108 x 62	648 x 108 x 62
Tower footprint with basin (l x w) (ft)	274 x 112	436 x 112	652 x 112

3.3.2 LOCATION

The initial site selection for each tower was based on the desire to locate each tower as close as possible to the respective generating units to minimize the supply and return pipe distances and any increases in total pump head and brake horsepower. The limited space and configuration of AGS requires placement of Tower 1, serving Units 1 and 2, in the facility's southernmost area. This results in supply and return pipe distances of approximately 3,500 feet (each direction). Tower 2 serves Units 3 and 4 and is located immediately east of those units (Figure A–4). Tower 3 serves Units 5 and 6 and is located immediately south of the power block (Figure A–5).[4]

A 35-foot high concrete barrier wall (not shown) will be constructed on each tower's north and west sides to reduce the noise from falling water and enable compliance with local noise ordinances. Barrier walls will not be required on the tower's south or east sides because the potential for noise impacts in those directions is low.

[4] Figures A-4 and A-5 are not to the same scale.

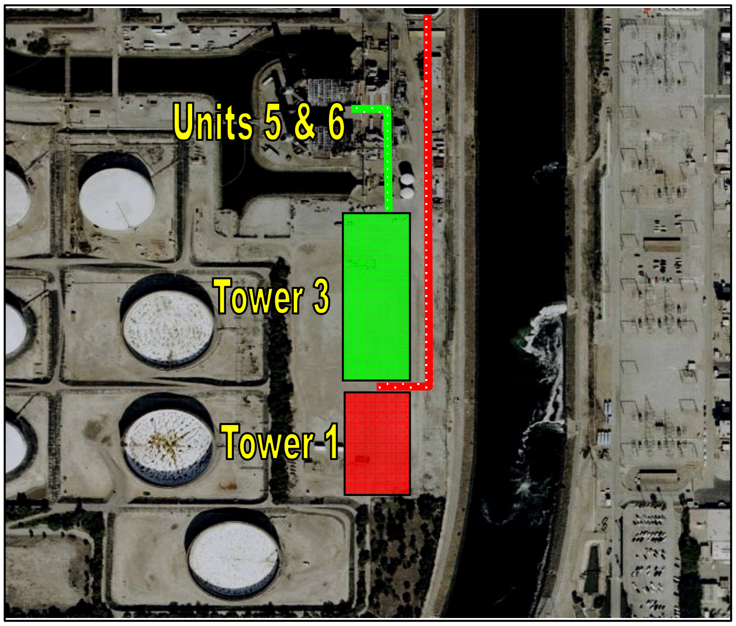

Figure A–4. Location of Tower 1 and Tower 3

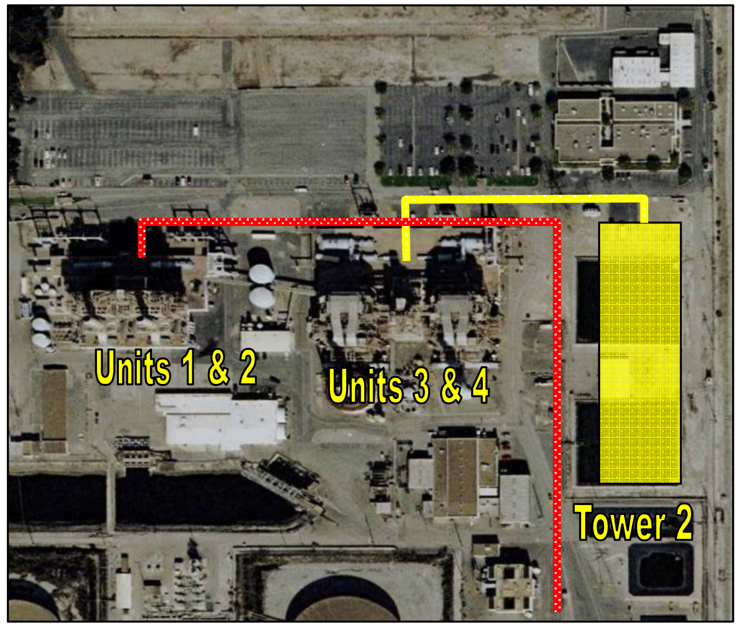

Figure A–5. Location of Tower 2

3.3.3 PIPING

The main supply and return pipelines for Tower 1 and Tower 2 will be located underground and made of prestressed concrete cylinder pipe (PCCP) suitable for salt water applications. These pipes range in size from 72 to 96 inches in diameter. The distance between Units 1 and 2 and Tower 1 requires roughly 7,500 feet of PCCP for the supply and return lines. An additional 1,100 feet are used for Tower 2. Pipes connecting the condensers to the supply and return lines are made of FRP and placed above ground on pipe racks. Above ground placement avoids the potential disruption that may be caused by excavation in and around the power block. The condensers at AGS are all located at grade level, enabling a relatively straightforward connection.

The relative proximity of Tower 3 to Units 5 and 6 enables placement of nearly all piping above ground on pipe racks. Pipes are made of FRP except for the cooling water supply headers to the tower, which are PCCP and placed underground.

Potential interference with underground obstacles and infrastructure is a concern, particularly at existing sites that are several decades old and have been substantially modified or rebuilt in the interim. Avoidance of these obstacles is considered to the degree practical in this study. Associated costs are included in the contingency estimate and are generally higher than similar estimates for new facilities (Section 4.3).

Appendix B details the total quantity of each pipe size and type for AGS.

3.3.4 FANS AND PUMPS

Each tower cell uses an independent single-speed fan. Low noise fan blades, gear box insulation and fan deck barrier walls are included to reduce operating noise and allow compliance with local noise ordinances. The fan size and motor power are the same for each cell in each tower.

This analysis includes new pumps to circulate water between the condensers and cooling towers. Pumps are sized according to the flow rate for each tower, the relative distance between the towers and condensers, and the total head required to deliver water to the top of each cooling tower riser. A separate, multilevel pump house is constructed for each cooling tower and is sized to accommodate the motor control centers (MCCs) and appropriate electrical switchgear. The electrical installation includes all necessary transformers, cabling, cable trays, lighting, and lightning protection. A 50-ton overhead crane is also included to allow for pump servicing.

Fan and pump characteristics associated with wet cooling towers at AGS are summarized in Table A–8. The net electrical demand of fans and new pumps is discussed further as part of the energy penalty analysis in Section 4.6.1.

Table A–8. Cooling Tower Fans and Pumps

		Tower 1 (Units 1 & 2)	Tower 2 (Units 3 & 4)	Tower 3 (Units 5 & 6)
Fans	Number	10	16	24
	Type	Low noise Single speed	Low Noise Single speed	Low Noise Single speed
	Efficiency	0.95	0.95	0.95
	Motor power (hp)	263	263	263
Pumps	Number	2	2	2
	Type	50% recirculating Mixed flow Suspended bowl Vertical	50% recirculating Mixed flow Suspended bowl Vertical	50% recirculating Mixed flow Suspended bowl Vertical
	Efficiency	0.88	0.88	0.88
	Motor power (hp)	2,023	3,375	5,216

3.4 ENVIRONMENTAL EFFECTS

Converting the existing once-through cooling system at AGS to wet cooling towers will significantly reduce the intake of seawater from Los Cerritos Channel and will presumably reduce impingement and entrainment by a similar proportion. Because closed-cycle systems will almost always result in condenser cooling water temperatures higher than those found in a comparable once-through system, wet towers will increase the operating heat rates at all six of AGS's steam units, thereby decreasing the facility's overall efficiency. Additional power will also be consumed by the operation of tower fans and circulating pumps.

Depending on how AGS chooses to address this change in efficiency, total stack emissions may increase for pollutants such as PM_{10}, SO_x, and NO_x, and may require additional control measures (e.g., electrostatic precipitation, flue gas desulfurization, and selective catalytic reduction) or the purchase of emission credits to meet air quality regulations. The availability of emission reduction credits (ERCs) and their associated cost was not evaluated as part of this study. Both factors, however, may limit the air emission compliance options available to AGS.

No control measures are currently available for CO_2 emissions, which will increase, on a per-kWh basis, by the same proportion as any change in the heat rate. The towers themselves will constitute an additional source of PM_{10} emissions, the annual mass of which will largely depend on the capacity utilization rate for the generating units served by each tower.

If AGS retains its NPDES permit to discharge wastewater to the San Gabriel River with a wet cooling tower system, it may have to address revised effluent limitations resulting from the substantial change in the discharge quantity and characteristics. Thermal impacts from the current once-through system, if any, will be minimized with a wet cooling system.

3.4.1 AIR EMISSIONS

AGS is located in the South Coast air basin. Air emissions are permitted by the South Coast Air Quality Management District (SCAQMD) (Facility ID 115394).

Drift volumes are expected to be within the range of 0.5 gallons for every 100,000 gallons of circulating water in the towers. At AGS, this corresponds to a rate of approximately 4 gpm based on the maximum combined flow in the three towers.

Optimal cooling tower placement considers the relative location of sensitive structures as well as the direction of prevailing winds to minimize any interference or impact from drift deposition. Given the spatial constraints at AGS, however, potential impacts cannot always be avoided. Areas potentially affected by drift deposition include residential neighborhoods located to the northwest, the switchyard located to the north, and the HnGS switchyard located on the opposite bank of the San Gabriel River. No agricultural areas are present in the vicinity of AGS that could potentially be impacted by drift.

Total PM_{10} emissions from the AGS cooling towers are a function of the number of hours in operation, the overall water quality in the tower, and the evaporation rate of drift droplets prior to deposition on the ground. Makeup water at AGS will be obtained from the same source currently used for once-through cooling water (Los Cerritos Channel). This water is drawn through Alamitos Bay from the Pacific Ocean and mixes with a small volume of fresh water from upland locations. The water quality, however, is substantially similar to marine water with respect to the total dissolved solids (TDS) concentration. At 1.5 cycles of concentration and assuming an initial TDS value of 35 parts per thousand (ppt), the water within the cooling towers will reach a maximum TDS level of roughly 53 ppt. Any drift droplets exiting the tower will have the same TDS concentration.

The cumulative mass emission of PM_{10} from AGS will increase as a result of the direct emissions from the cooling towers themselves. Stack emissions of PM_{10}, as well as SO_x, NO_x, and other pollutants, will increase due to the drop in fuel efficiency, although the cumulative increase will depend on actual operations and emission control technologies currently in use. Maximum drift and PM_{10} emissions from the cooling towers are summarized in Table A–9.

Data summarizing the total facility emissions for these pollutants in 2005 are presented in Table A–10 (CARB 2005). In 2005, AGS operated at an annual capacity utilization rate of 7.1 percent. Using this rate, the additional PM_{10} emissions from the cooling towers would increase the facility total by approximately 32 tons/year, or 79 percent. [5]

Table A–9. Full Load Drift and Particulate Estimates

	PM_{10} (lbs/hr)	PM_{10} (tons/year)	Drift (gpm)	Drift (lbs/hr)
Tower 1	18	79	0.69	343
Tower 2	34	149	1.30	648
Tower 3	53	233	2.02	1,011
Total AGS PM_{10} and drift emissions	**105**	**461**	**4.01**	**2,002**

Table A–10. 2005 Emissions of SOx, NOx, PM10

Pollutant	Tons/year
NO_x	71.3
SO_x	7.2
PM_{10}	40.6

3.4.2

3.4.3 MAKEUP WATER

The volume of makeup water required by the three cooling tower at AGS is the sum of evaporative loss and the blowdown volume required to maintain the circulating water in each tower at the design TDS concentration (Table A-11). Drift expelled from the towers represents an insignificant volume by comparison and is accounted for by rounding up estimates of evaporative losses. Makeup water volumes are based on design conditions, and may fluctuate seasonally depending on climate conditions and facility operations. Use of wet cooling towers will reduce once-through cooling water withdrawals from Los Cerritos Channel by approximately 95 percent over the current design intake capacity.

Table A–11. Makeup Water Demand

	Tower circulating flow (gpm)	Evaporation (gpm)	Blowdown (gpm)	Total makeup water (gpm)
Tower 1	137,000	2,700	5,400	**8,100**
Tower 2	259,000	4,500	9,000	**13,500**
Tower 3	404,200	5,900	11,700	**17,600**
Total AGS makeup water demand	**800,200**	**13,100**	**26,100**	**39,200**

[5] 2006 emission data are not currently available from the ARB website. For consistency, the comparative increase in PM_{10} emissions estimated here is based on the 2005 AGS capacity utilization rate instead of the 2006 rate presented in Table A–4. All other calculations in this chapter use the 2006 value.

One circulating water pump, rated at 68,000 gpm, which is currently used to provide once-through cooling water to the facility, will be retained in a wet cooling system to provide makeup water to each cooling tower. The retained pump's capacity exceeds the makeup demand by approximately 29,000 gpm. Any excess capacity will be routed through a bypass conduit and returned to the wet well at a point located behind the intake screens. Recirculating the excess capacity in this manner reduces additional cost that would be incurred if new pumps were required while maintaining the desired flow reduction. The intake of new water, measured at the intake screens, will be equal to the cooling towers' makeup water demand. Figure A–6 presents a schematic of this configuration.

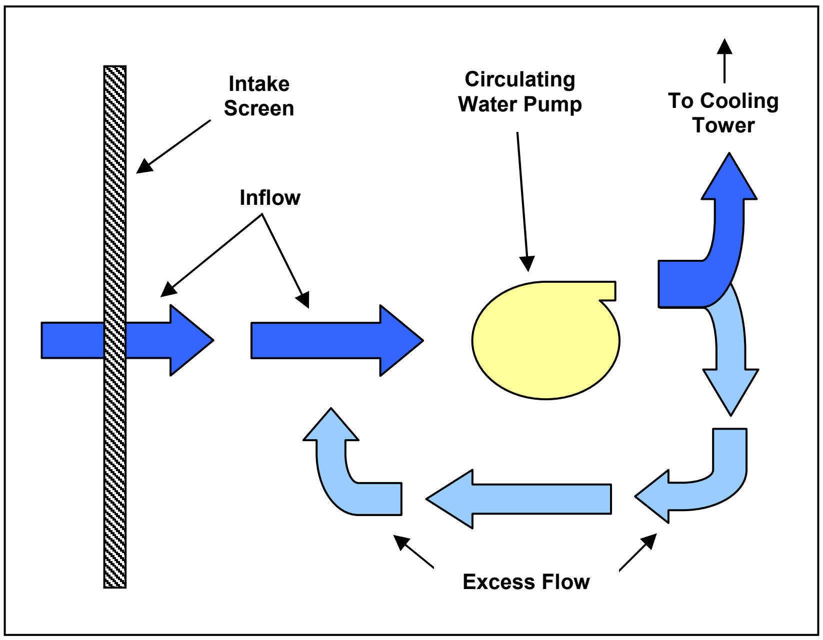

Figure A–6. Schematic of Intake Pump Configuration

The existing once-through cooling system at AGS does not treat water withdrawn from Los Cerritos Channel, with the exception of screening for debris and larger organisms and periodic chlorination to control biofouling in the condenser tubes. Heat treatments are also periodically used to control mussel growth on pipes and condenser tubes by raising the circulating water temperature to 120º F. Conversion to a wet cooling tower system will not interfere with chlorination or heat treatment operations.

Makeup water will continue to be withdrawn from the Los Cerritos Channel.

The wet cooling tower system proposed for AGS includes water treatment for standard operational measures, i.e., fouling and corrosion control. Chemical treatment allowances are included in annual operations and maintenance (O&M) costs. It is assumed that the current once-through cooling water quality will be acceptable for use in a seawater cooling tower (with continued screening) and will not require any pretreatment to enable its use.

3.4.4 NPDES PERMIT COMPLIANCE

At maximum operation, wet cooling towers at AGS will result in an effluent discharge of approximately 38 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, treated sanitary waste, and cleaning wastes. These low volume wastes may add an additional 3.5 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, AGS will be required to modify its existing individual wastewater discharge (NPDES) permit. Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0001139, as implemented by LARWQCB Order 00-082. All wastewaters are discharged to the San Gabriel River through one of three separate outfalls.

The existing Order contains effluent limitations based on the 1997 Ocean Plan and 1972 Thermal Plan. By letter dated January 21, 2003, the LARWQCB notified AGS that the facility's receiving water, the San Gabriel River, had been reclassified from a marine water body to an estuarine water body for the purposes of wastewater discharge permitting (LARWQCB 2003). Thus, in subsequent permit renewals, any water quality-based effluent limitations (WQBELs) will be based on the California Toxics Rule (CTR) and the State Implementation Policy for Inland Waters (SIP).

AGS will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities (40 CFR 423.13(d)(1)). These ELGs set numeric limitations for chromium and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity). Because ELGs are technology-based limitations, mixing zones or dilution factors are not applicable when determining compliance; limits must be met at the point of discharge from the cooling tower prior to commingling with any other waste stream. ELGs for cooling tower blowdown target priority pollutants that are contributed by maintenance chemicals and do not apply when limits may be exceeded as a result of background concentrations or other sources. Further discussion can be found in Chapter 4, Section 3.6.

Conversion to wet cooling towers will alter the volume and composition of a facility's wastewater discharge because wet towers concentrate certain pollutants in the effluent waste stream. The cooling towers designed for AGS operate at 1.5 cycles of concentration, i.e., the blowdown discharge will contain a dissolved solids concentration 50 percent higher than the makeup water.

Changes to discharge composition may affect compliance with water quality criteria included in the SIP. If compliance with these objectives becomes problematic, alternative treatment or discharge methods may be necessary. Data submitted by AGS in support of its NPDES renewal application demonstrates a reasonable potential to exceed effluent limitations for copper, zinc, and cyanide (AES 2004). These assessments reflect the existing once-through cooling system and, for zinc and copper, are primarily driven by the elevated concentrations detected in the intake water at AGS. Compliance may be achieved by altering the discharge configuration in such a way as to increase dilution (e.g., diffuser ports), or by seeking a mixing zone and dilution credits as permissible under the SIP and Basin Plan. Alternately, some low volume waste streams (e.g., boiler blowdown, laboratory drains) may be diverted, with necessary permits, for treatment at a POTW.

The SIP does make an allowance for intake credits under some circumstances but none would be applicable to AGS due to the fact that a cooling tower effectively changes the intake water characteristics by concentrating pollutants (through evaporation) by as much as 50 percent above their initial levels. In addition, the current receiving water (San Gabriel River) may not meet the criteria establishing it as “hydrologically connected” to Los Cerritos Channel (SWRCB 2000).

If more pollutant-specific treatment methods, such as filtration or precipitation technologies, become necessary to meet WQBELs, the initial capital cost may range from $2 to $5.50 per 1,000 gallons of treatment capacity, with annual costs of approximately $0.5 per gallon of capacity, depending on the method of treatment (FRTR 2002). Hazardous material disposal fees and permits would further increase costs.

This evaluation did not include alternative discharge or effluent treatment measures in the conceptual design because the variables used to determine final WQBELs, which would be used to determine the type and scope of the desired compliance method, cannot be quantified here. Likewise, the final cost evaluation (Section 4.0) does not include any allowance for these possibilities.

Use of reclaimed water as the cooling tower makeup source has the potential to reduce or eliminate conflicts with effluent limitations (see Section 3.4.4)

Existing thermal discharges to an estuary are limited to a maximum discharge temperature of 20º F above the receiving water’s natural temperature, may not exceed 86º F, and meet other criteria specified by the Thermal Plan (SWRCB 1972). It is unclear if AGS will be able to meet this thermal limitation based on the current once-through configuration, with discharge temperatures reaching as high as 100 ºF and ambient water temperatures in the mid to upper 60s. Compliance is also uncertain with wet cooling towers but is more likely given that blowdown discharge will be taken from the cold water side of the system, ensuring an effluent discharge temperature not in excess of 83º F for normal operations (not including heat treatments). This temperature is below the maximum permissible discharge temperature and within the required 20º F range of ambient temperatures in the San Gabriel River, although other criteria would also have to be met.

3.4.5 RECLAIMED WATER

The use of reclaimed or alternative water sources could potentially eliminate all surface water withdrawals at AGS. Doing so would completely eliminate impingement and entrainment concerns, and might enable the facility to avoid possible effluent quality and permit compliance issues, depending on the quality of reclaimed water available for use. In addition, wet cooling towers using reclaimed water would be expected to have lower PM_{10} emissions due to the lower TDS levels. The California State Water Resources Control Board (SWRCB), in 1975, issued a policy statement requiring the consideration of alternative cooling methods in new power plants, including the use of reclaimed water, over the use of freshwater (SWRCB 1975). There is no similar policy regarding the use of marine waters, but the clear preference of state agencies is to encourage alternative cooling methods, including the use of reclaimed water, wherever possible.

The present volume of available reclaimed water within a 15-mile radius of AGS (635 mgd) does not meet the current once-through cooling demand; thus, the use of reclaimed water is only applicable as a source of makeup water for a wet cooling tower system. This study did not pursue a detailed investigation of reclaimed water's use of because the conversion of AGS's once-through cooling system to saltwater cooling towers enables the facility to meet the performance targets for impingement and entrainment impact reductions discussed in the 2006 California Ocean Protection Council (OPC) Resolution on Once-Through Cooling Water (see Chapter 1).

To be acceptable for use as makeup water in cooling towers, reclaimed water must meet tertiary treatment and disinfection standards under California Code of Regulations (CCR) Title 22. If the reclaimed water is not treated to the required levels, AGS would be required to arrange for sufficient treatment, either onsite or at the source facility, prior to its use in the cooling towers.

An additional consideration for the use of reclaimed water is the presence of any ammonia or ammonia-forming compounds in the reclaimed water. All the condenser tubes at AGS contain copper alloys (aluminum brass and copper-nickel) and can experience stress-corrosion cracking as a result of the interaction between copper and ammonia. Treatment for ammonia may include the addition of ferrous sulfate as a corrosion inhibitor or require ammonia-stripping towers to pretreat reclaimed water prior to use in the cooling towers (EPA 2001).

Five publicly owned treatment works (POTWs) were identified within a 15-mile radius of AGS, with a combined discharge capacity of 635 mgd. Figure A–7 shows the relative locations of these facilities to AGS.

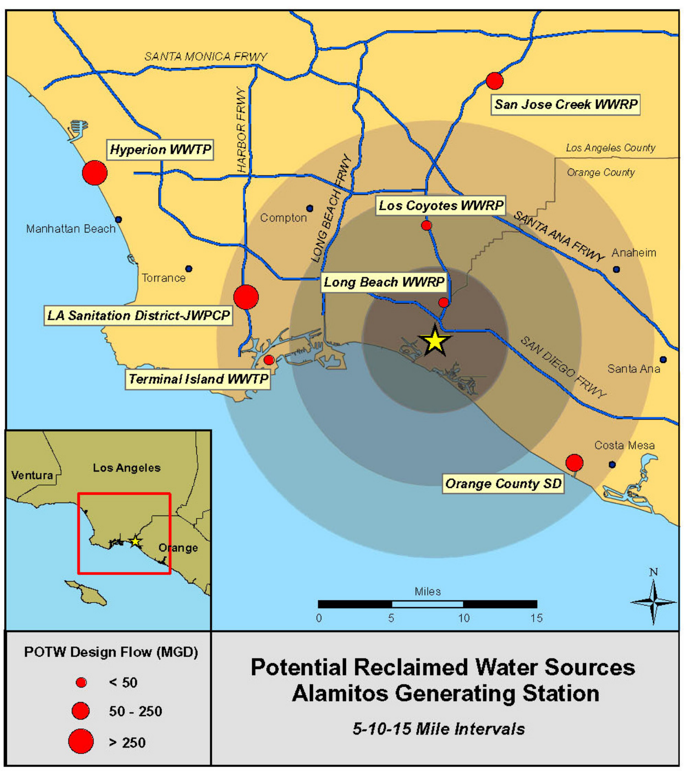

Figure A–7. Reclaimed Water Sources

- *Los Angeles Sanitation District, Joint Water Pollution Control Plant (JWPCP)—Carson*.
  Discharge Volume: 330 mgd
  Distance: 14 miles NW
  Treatment Level: Secondary

  The facility representative at JWPCP indicated that the effluent is not currently considered a potential source of reclaimed water for irrigation due to high TDS concentrations (brine from the Hyperion WWTP is treated at Carson), but the suitability for use as a makeup water source is not currently known. TDS levels may be less than normally found in seawater and thus be at least comparable with the current makeup water source at AGS. In the future, a portion of the effluent may be used for a new hydrogen plant under consideration by BP, but no formal agreement currently exists. Even with such an agreement, sufficient capacity would remain to satisfy the full makeup water demand for freshwater towers at AGS (23 to 26 mgd).

- *Los Coyotes Wastewater Reclamation Plant—Cerritos.*
  Discharge Volume: 33 mgd
  Distance: 9 miles N
  Treatment Level: 30 % tertiary; 70 % secondary

  Approximately 10 MGD are treated to tertiary standards and reused for irrigation at various locations in the area, leaving approximately 23 mgd available as a makeup water source. The remaining 23 mgd would require additional treatment prior to use at AGS.

- *Terminal Island Wastewater Treatment Plant—San Pedro.*
  Discharge Volume: 20 mgd
  Distance: 10 miles W
  Treatment Level: 10 % tertiary; 90 % secondary

  Tertiary treated water is used for local irrigation. A previous study to assess the feasibility of using Terminal Island's reclaimed water at Harbor Generating Station determined the water quality (pH) would have adverse effects on the condenser and cooling system, although treatment systems could be installed on site to condition the water to an acceptable pH level.[6]

- *Orange County Sanitation District Wastewater Treatment Plant—Huntington Beach.*
  Discharge Volume: 232 mgd
  Distance: 13 miles SE
  Treatment Level: Secondary

  Sufficient capacity exists to supply the full makeup water demand for freshwater towers at AGS (23 to 26 mgd), although any use would require additional on-site treatment.

- *Long Beach Wastewater Treatment Plant—Long Beach.*
  Discharge Volume: 20 mgd
  Distance: 3 miles N
  Treatment Level: Tertiary

[6] This study was referenced in documents provided by LADWP but not available for review.

Approximately 50 percent is currently used for irrigation in the vicinity the plant. The remaining capacity could supply 20 to 30 percent of the makeup water demand for freshwater cooling tower.

The costs associated with the installing transmission pipelines (excavation/drilling, material, labor), in addition to design and permitting costs, are difficult to quantify in the absence of a detailed analysis of various site-specific parameters that will influence the final configuration. The nearest facility with sufficient capacity to satisfy AGS's makeup demand (23 to 26 mgd as a freshwater tower) is located approximately 10 miles from the site (JWPCP). Transmission pipelines would have to traverse a heavily-urbanized area and navigate infrastructure obstacles such as freeways and flood control channels.

Based on data compiled for this study, the estimated installed cost of a 36-inch prestressed concrete cylinder pipe, sufficient to provide 26 mgd to AGS, is $514 per linear foot, or approximately $2.7 million per mile. Additional considerations, such as pump capacity and any required treatment, would increase the total cost.

Regulatory concerns beyond the scope of this investigation, however, may make the use of reclaimed water as makeup water comparable or preferable to the use of saltwater from marine sources. Reclaimed water may enable AGS to reduce PM_{10} emissions from the cooling tower, which is a concern given the South Coast air basin's current nonattainment status, or eliminate potential conflicts with water discharge limitations. Use of reclaimed water might also mitigate impacts of high-salinity drift on sensitive equipment.

At any facility where wet cooling towers are a feasible alternative, reclaimed water may be used as a makeup water source. The practicality of its use, however, depends on the overall cost, availability, and additional environmental benefit that may occur.

3.4.6 THERMAL EFFICIENCY

The use of wet cooling towers at AGS will increase the condenser inlet water temperature by a range of 11 to 15° F above the surface water temperature, depending on the ambient wet bulb temperature at the time. The generating units at AGS are designed to operate at the conditions described in Table A–12. The resulting monthly difference between once-through and wet cooling tower condenser inlet temperatures at AGS is described in Figure A–8.

Table A–12. Design Thermal Conditions

	Units 1 & 2	Units 3 & 4	Units 5 & 6
Design backpressure (in. HgA)	1.69	1.5	1.5
Design water temperature (°F)	63	63	63
Turbine inlet temp (°F)	1,000	1,000	1,000
Turbine inlet pressure (psia)	2,400	2,400	2,400
Full load heat rate (BTU/kWh) [a]	11,566	9,800	9,680

[a] CEC 2002.

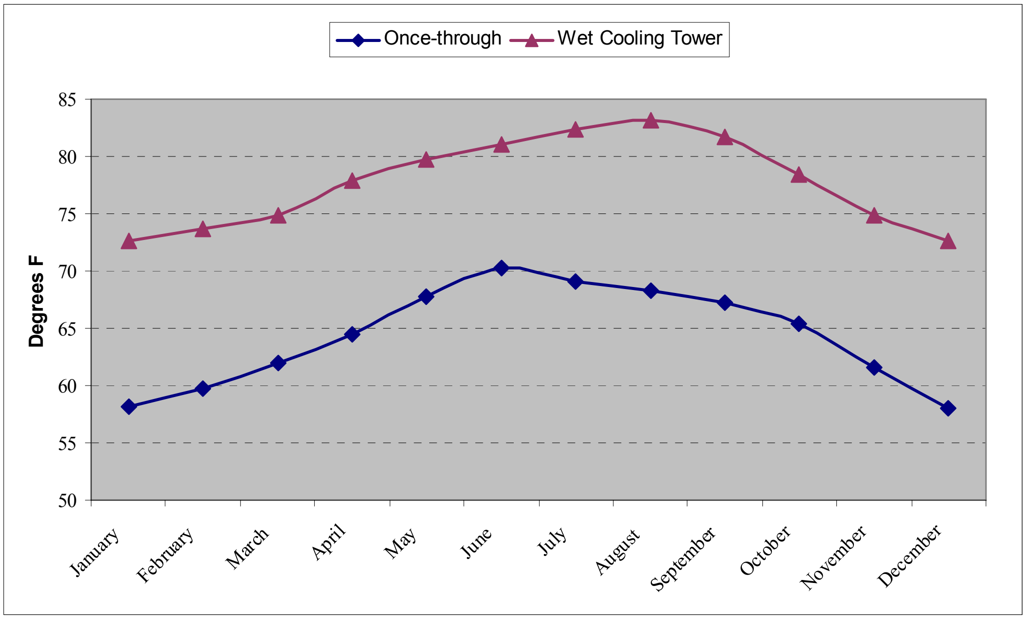

Figure A–8. Condenser Inlet Temperatures

Backpressures for the once-through and wet cooling tower configurations were calculated for each month using the design criteria described in the sections above and ambient climate data (Table A–6). In general, backpressures associated with the wet cooling tower were elevated by 0.6 to 0.95 inches HgA compared with the current once-through system (Figure A–9, Figure A–11, and Figure A–13).

Heat rate adjustments were calculated by comparing the theoretical change in available energy that occurs at different turbine exhaust backpressures, assuming the thermal load and turbine inlet pressure remain constant, i.e., at the full load rating.[7] The relative change at different backpressures was compared with the value calculated for the design conditions (i.e., at design turbine inlet and exhaust backpressures) and plotted as a percentage of the full load operating heat rate (Table A–12) to develop estimated correction curves (Figure A–10, Figure A–12, and Figure A–14).

The difference between the estimated once-through and closed-cycle heat rates for each month represents the approximate heat rate increase that would be expected when converting to wet cooling towers.

Table A–13 summarizes the annual average heat rate increase for each unit as well as the increase associated with the peak demand period of July-August-September. Monthly values were used to calculate the monetized value of these heat rate changes (Section 4.6). Month-by-month calculations are presented in Appendix A.

[7] Changes in thermal efficiency estimated for AGS are based on the design specifications provided by the facility. This may not reflect system modifications that might influence actual performance. In addition, the age of the units and the operating protocols used by AGS might result in different calculations.

Table A-13. Summary of Estimated Heat Rate Increases

	Units 1 & 2	Units 3 & 4	Units 5 & 6
Peak (July-August-September)	1.69%	1.73%	1.67%
Annual average	1.39%	1.45%	1.35%

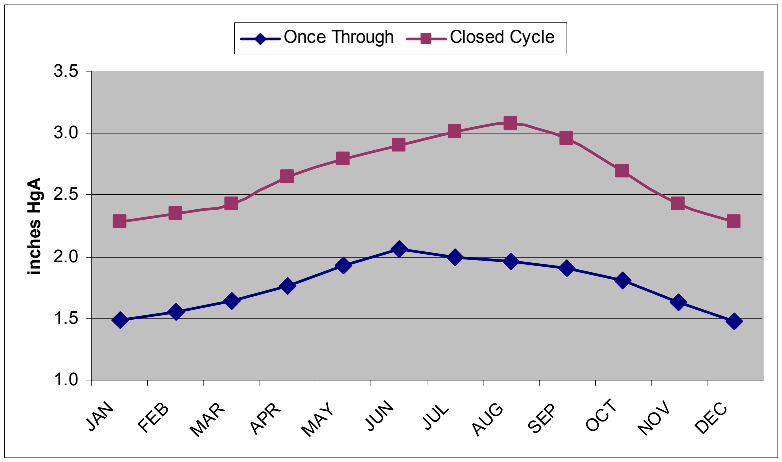

Figure A-9. Estimated Backpressures (Units 1 & 2)

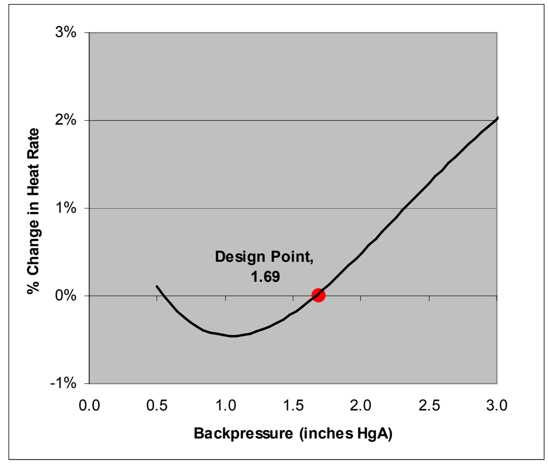

Figure A-10. Estimated Heat Rate Correction (Units 1 & 2)

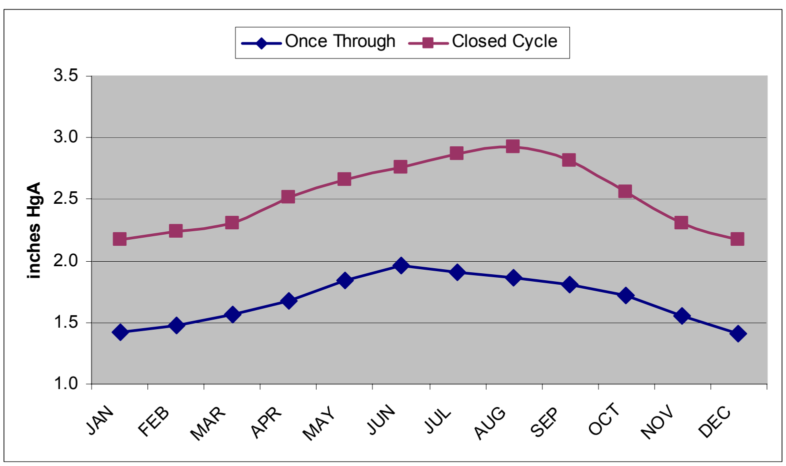

Figure A-11. Estimated Backpressures (Units 3 & 4)

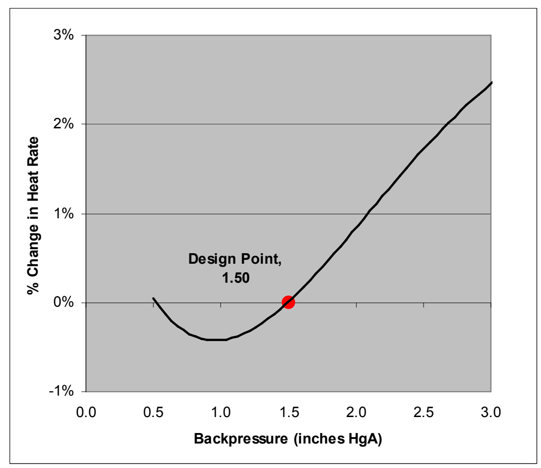

Figure A-12. Estimated Heat Rate Correction (Units 3 & 4)

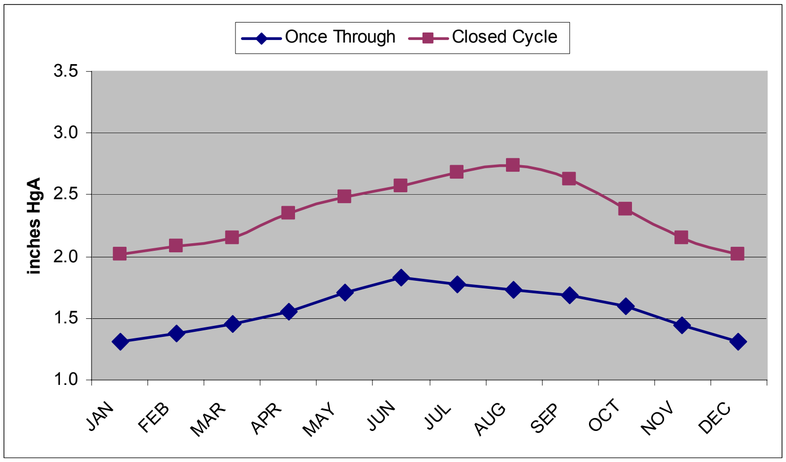

Figure A–13. Estimated Backpressures (Units 5 & 6)

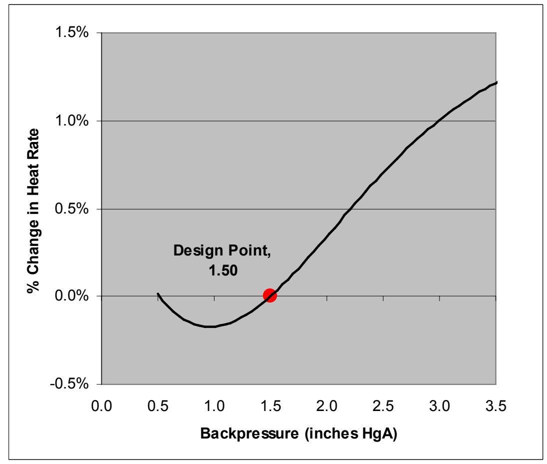

Figure A–14. Estimated Heat Rate Correction (Units 5 & 6)

4.0 RETROFIT COST ANALYSIS

The wet cooling system retrofit estimate for AGS is based on incorporating conventional wet cooling towers as a replacement for the existing once-through systems for each unit. Standard cost elements for this project include the following:

- Direct (cooling tower installation, civil/structural, mechanical, piping, electrical, and demolition)
- Indirect (smaller project costs not itemized)
- Contingency (allowance for unknown project variables)
- Revenue loss from shutdown (net loss in revenue during construction phase)
- Operations and maintenance (non–energy related cooling tower operations)
- Energy penalty (includes increased parasitic use from fans and pumps as well as decreased thermal efficiency)

4.1 COOLING TOWER INSTALLATION

The wet cooling towers selected for AGS are arranged in a back-to-back configuration instead of the more common in-line layout. This results in a taller structure and increases the per-cell cost. In addition, the inclusion of low noise fans and fan deck barrier walls represent a modest increase in cost for the towers over a conventional system. Table A–14 summarizes the design-and-build cost estimate for each tower developed by vendors, inclusive of all labor and management required for their installation.

Table A–14. Wet Cooling Tower Design-and-Build Cost Estimate

	Units 1 & 2	Units 3 & 4	Units 5 & 6	AGS Total
Number of cells	10	16	24	**50**
Cost/cell ($)	640,000	612,500	612,500	**618,000**
Total AGS D&B cost ($)	**6,400,000**	**9,800,000**	**14,700,000**	**30,900,000**

4.2 OTHER DIRECT COSTS

A significant portion of wet cooling tower installation costs result from the various support structures, materials, equipment and labor necessary to prepare the cooling tower site and connect the towers to the condenser. At AGS, these costs comprise approximately 45 percent of the initial capital cost. Line item costs are detailed in Appendix B.

Deviations from or additions to the general cost elements discussed in Chapter 5 are discussed below. Other direct costs (non–cooling tower) are summarized in Table A–15.

- *Civil, Structural, and Piping*
  The configuration of the AGS site allows Towers 2 and 3 to be located relatively close to their respective units. Tower 1, however, must be placed at a substantial distance from Units 1 and 2. The distance (approximately 3,700 ft) required for Tower 1 notably increases material and labor costs—primarily as they relate to installing supply and return piping (approximately 7,500 ft total). Total costs are also affected by the necessity of constructing a 35-foot high concrete barrier wall to meet Long Beach noise control ordinances.
- *Mechanical and Electrical*
  Initial capital costs in this category reflect the new pumps (eight total) required to circulate cooling water between the towers and condensers. Overall pump capacity is larger than a baseline arrangement as a result of dividing the cooling tower for each unit into two separate towers. No new pumps are required to provide makeup water from the Pacific Ocean. Electrical costs are based on the battery limit after the main feeder breakers.
- *Demolition*
  A small cost is included for the demolition and backfilling of the two retention basins that will be removed to make room for Tower 2. The nature of materials treated in these basins is unknown; the estimate does not include an allowance for hazardous materials clean up and disposal.

Table A–15. Summary of Other Direct Costs

	Equipment ($)	Bulk material ($)	Labor ($)	AGS total ($)
Civil/structural/piping	8,900,000	37,000,000	30,500,000	**76,400,000**
Mechanical	10,600,000	0	900,000	**11,500,000**
Electrical	2,600,000	4,100,000	2,800,000	**9,500,000**
Demolition	0	600,000	200,000	**800,000**
Total AGS other direct costs	**22,100,000**	**41,700,000**	**34,400,000**	**98,200,000**

4.3 INDIRECT AND CONTINGENCY

Indirect costs are calculated as 25 percent of all direct costs (civil/structural, mechanical, electrical, demolition, and cooling towers).

An additional allowance is included for condenser water box and tube sheet reinforcement to withstand the increased pressures associated with a recirculating system. Each condenser may require reinforcement of the tube sheet bracing with 6-inch x 1-inch steel, and water box reinforcement/replacement with 5/8-inch carbon steel. Based on the estimates outlined in Chapter 5, a conservative estimate of 5 percent of all direct costs is included to account for possible condenser modifications.

The contingency cost is calculated as 25 percent of the sum of all direct and indirect costs, including condenser reinforcement. At AGS, potential costs in this category include relocation or demolition of small buildings and structures and the potential interference with underground structures. Soils were not characterized for this analysis. AGS lies within the coastal plain at approximately 10 feet above sea level and is bordered by water to the east and west. Groundwater intrusion or the instability of soils may require additional pilings to support any large structures built at the site. Initial capital costs are summarized in Table A–16.

Table A–16. Summary of Initial Capital Costs

	Cost ($)
Cooling towers	30,900,000
Civil/structural/piping	76,400,000
Mechanical	11,500,000
Electrical	9,500,000
Demolition	800,000
Indirect cost	32,300,000
Condenser modification	6,500,000
Contingency	42,000,000
Total AGS capital cost	**209,900,000**

4.4 SHUTDOWN

A portion of the work relating to installing wet cooling towers can be completed without significant disruption to the operations of AGS. Units will be offline depending on the length of time it takes to integrate the new cooling system and conduct acceptance testing. For AGS, a conservative estimate of 4 weeks per unit was developed. Based on 2006 generating output, however, no shutdown is forecast for either unit. Therefore, the cost analysis for AGS does not include any loss of revenue associated with shutdown at AGS.

This analysis did not consider shutdown with respect to the required availability of a particular generating unit, nor can it automatically be assumed that the generating profile for 2006 will be the same in each subsequent year. Net output data from 2006 may not reflect any contractual obligations that mandate a particular unit's availability during a given time period.

4.5 OPERATIONS AND MAINTENANCE

Operations and maintenance (O&M) costs for a wet cooling tower system at AGS include routine maintenance activities; chemicals and treatment systems to control fouling and corrosion in the towers; management and labor; and an allowance for spare parts and replacement. Annual costs are calculated based on the combined tower flow rate using a base cost of $4.00/gpm in Year 1 and $5.80/gpm in Year 12, with an annual escalator of 2 percent (USEPA 2001). Year 12 costs increase based on the assumption that maintenance needs, particularly for spare parts and replacements, will be greater for years 12–20. Annual O&M costs, based on the design circulating water flow for the two cooling towers at AGS (800,200 gpm), are presented in Table A–17. These costs reflect maximum operation.

Table A–17. Annual O&M Costs (Full Load)

	Year 1 Cost ($)	Year 12 Cost ($)
Management/labor	800,200	1,160,290
Service/parts	1,280,320	1,856,464
Fouling	1,120,280	1,624,406
Total AGS O&M cost	**3,200,800**	**4,641,160**

4.6 ENERGY PENALTY

The energy penalty is divided into two components: increased parasitic use resulting from the additional electrical demand of cooling tower fans and pumps; and the decrease in thermal efficiency resulting from elevated turbine backpressure values. Monetizing the energy penalty at AGS requires some assumption as to how the facility will choose to alter its operations to compensate for these changes, if at all. One option would be to accept the reduced amount of revenue-generating electricity available and absorb the economic loss ("production loss option"). A second option would be to increase the firing rate to the turbine (i.e., consume more fuel) and produce the same amount of revenue-generating electricity as had been obtained with the once-through cooling system ("increased fuel option"). A more likely option, however, is some combination of the two.

Ultimately, the manner in which AGS would alter operations to address efficiency changes is driven by considerations unknown to this study (e.g., corporate strategy, contractual obligations, operating protocols and turbine pressure tolerances). In all summary cost estimates, this study calculates the energy penalty's monetized value by assuming the facility will use the increased fuel option to compensate for reduced efficiency and generate the amount of electricity equivalent to the estimated shortfall. With this option, the energy penalty is equivalent to the financial cost of additional fuel and is nominally less costly than the production loss option. This option, however, may not reflect long-term costs such as increased maintenance or system degradation that may result from continued operation at a higher-than-designed turbine firing rate.[8]

The energy penalty for AGS is calculated by first estimating the increased parasitic demand from the cooling tower pumps and fans, expressed as a percentage of each unit's or unit pair's rated capacity. Likewise, the change in the unit's heat rate is also expressed as a capacity percentage.

[8] Increasing the thermal load to the turbine will raise the circulating water temperature exiting the condenser. The cooling towers selected for this study are designed with a maximum water return temperature of approximately 120º F. Depending on each unit's operating conditions (i.e., condenser outlet temperature), the degree to which the thermal input to the turbine can be increased may be limited.

4.6.1 INCREASED PARASITIC USE (FANS AND PUMPS)

Depending on ambient conditions or the operating load at a given time, AGS may be able to take one or more cooling tower cells offline and still obtain the required level of cooling. This would also reduce the cumulative electrical demand from the fans. For the purposes of this study, however, operations are evaluated at the design conditions, i.e., full load; no allowance is made for seasonal changes. The increased electrical demand from cooling tower fan operation is summarized in Table A–18.

Table A–18. Cooling Tower Fan Parasitic Use

	Tower 1	Tower 2	Tower 3	AGS Total
Units served	Units 1&2	Units 3&4	Units 5&6	--
Generating capacity (MW)	350	650	950	**1,950**
Number of fans (one per cell)	10	16	24	**50**
Motor power per fan (hp)	263	263	263	--
Total motor power (hp)	2,632	4,211	6,316	**13,158**
MW total	1.96	3.14	4.71	**9.81**
Fan parasitic use (% of capacity)	**0.56%**	**0.48%**	**0.50%**	**0.50%**

The addition of new circulating water pump capacity for the wet cooling towers will also increase the parasitic use of electricity at AGS. Makeup water will continue to be withdrawn from Los Cerritos Channel with one of the existing circulating water pumps; the remaining pumps will be retired.

The net increase in pump-related parasitic usage is the difference between the new wet cooling tower configuration (new plus retained pumps) and the existing once-through configuration. For calculation purposes, this study assumes full-load operation to estimate the cost of increased parasitic use. Final estimates, therefore, allocate the retained pump's electrical demand to each tower based on the proportion of the facility's generating capacity it services. Operation of fewer towers or tower cells will alter the allocation of the retained pump's electrical demand, but not the total demand.

Because one of the main design assumptions maintains the existing flow rate through each condenser, the new circulating pumps are single speed and are assumed to operate at their full rated capacity when in use. The increased electrical demand associated with cooling tower pump operation is summarized in Table A–19.

Table A–19. Cooling Tower Pump Parasitic Use

	Tower 1	Tower 2	Tower 3	AGS Total
Units served	Units 1&2	Units 3&4	Units 5&6	--
Generating capacity (MW)	350	650	950	**1,950**
Existing pump configuration (hp)	2,140	3,440	5,200	**10,780**
New pump configuration (hp)	4,195	7,035	10,857	**22,087**
Difference (hp)	2,055	3,595	5,657	**11,307**
Difference (MW)	1.5	2.7	4.2	**8.4**
Net pump parasitic use (% of capacity)	**0.44%**	**0.41%**	**0.44%**	**0.43%**

4.6.2 HEAT RATE CHANGE

Adjustments to the heat rate were calculated based on the ambient conditions for each month and reflect the estimated difference between operations with once-through and wet cooling tower systems. As noted above, the energy penalty analysis assumes AGS will increase its fuel consumption to compensate for lost efficiency as well as the increased parasitic load from fans and pumps. The higher turbine firing rate will increase the thermal load rejected to the condenser, which, in turn, results in a higher backpressure value and corresponding increase in the heat rate.

No data are available describing the changes in turbine backpressures above the design thermal loads. For the purposes of monetizing the energy penalty only, this study conservatively assumed an additional increase in the heat rate of 0.5 percent at the higher firing rate; the actual effect at AGS may be greater or less. Changes in the heat rate for each unit at AGS are presented in Figure A–15, Figure A–16 and Figure A–17.

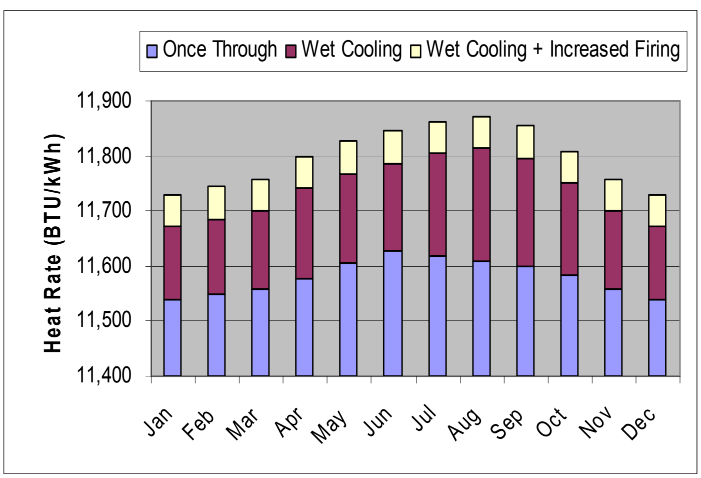

Figure A–15. Estimated Heat Rate Change (Units 1 & 2)

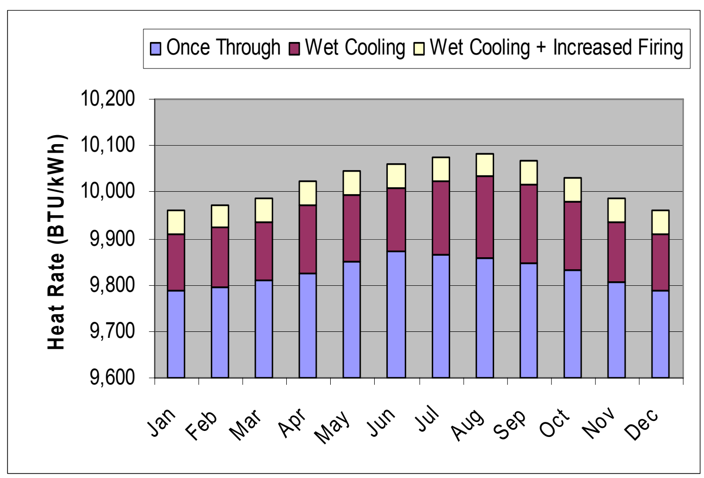

Figure A–16. Estimated Heat Rate Change (Units 3 & 4)

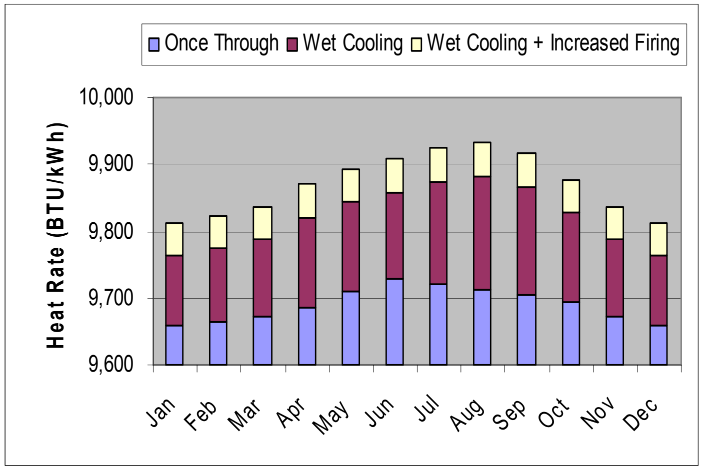

Figure A–17. Estimated Heat Rate Change (Units 5 & 6)

4.6.3 CUMULATIVE ESTIMATE

Using the increased fuel option, the energy penalty's cumulative value is obtained by first calculating the relative costs of generation ($/MWh) for the once-through system and the wet cooling system adjusted for a higher turbine firing rate. The cost of generation for AGS is based on the relative heat rates developed in Section 4.6.2 and the average monthly wholesale natural gas cost ($/MMBTU) (ICE 2006a). The difference between these two values represents the monthly increased cost, per MWh, that results from converting to wet cooling towers. This value is then applied to the net MWh generated for the each month and summed to calculate the annual cost.

Based on 2006 output data, the Year 1 energy penalty for AGS will be approximately $1.9 million. In contrast, the energy penalty's value calculated using the production loss option would be approximately $2.9 million. Together, these values represent the range of potential energy penalty costs for AGS. Table A–20, Table A–21 and Table A–22 summarize the energy penalty estimates for each unit using the increased fuel option.

Table A–20. Units 1 & 2 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	11,541	69.24	11,729	70.37	1.13	2,283	2,581
February	5.50	11,548	63.51	11,744	64.59	1.08	2,391	2,577
March	4.75	11,559	54.91	11,759	55.85	0.95	3,454	3,273
April	4.75	11,576	54.99	11,800	56.05	1.07	12,171	12,967
May	4.75	11,604	55.12	11,827	56.18	1.06	301	318
June	5.00	11,629	58.15	11,845	59.22	1.08	5,667	6,116
July	6.50	11,617	75.51	11,863	77.11	1.60	61,916	99,048
August	6.50	11,609	75.46	11,873	77.17	1.71	241	413
September	4.75	11,600	55.10	11,854	56.31	1.21	1,210	1,462
October	5.00	11,583	57.92	11,809	59.05	1.13	0	0
November	6.00	11,557	69.34	11,759	70.55	1.21	0	0
December	6.50	11,540	75.01	11,729	76.24	1.23	1,725	2,122
							Units 1 & 2 total	**130,877**

Table A–21. Units 3 & 4 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	9,789	58.73	9,960	59.76	1.03	20,640	21,250
February	5.50	9,797	53.88	9,973	54.85	0.97	27,072	26,284
March	4.75	9,808	46.59	9,986	47.43	0.84	9,331	7,871
April	4.75	9,825	46.67	10,022	47.60	0.93	63,683	59,511
May	4.75	9,852	46.80	10,044	47.71	0.91	66,633	60,940
June	5.00	9,874	49.37	10,060	50.30	0.93	112,281	104,184
July	6.50	9,863	64.11	10,075	65.49	1.38	178,206	245,351
August	6.50	9,856	64.06	10,083	65.54	1.47	63,338	93,399
September	4.75	9,847	46.77	10,067	47.82	1.05	64,159	67,068
October	5.00	9,832	49.16	10,029	50.15	0.99	31,980	31,537
November	6.00	9,806	58.84	9,986	59.92	1.08	29,243	31,561
December	6.50	9,788	63.62	9,960	64.74	1.12	46,593	52,275
							Units 3 & 4 total	**801,231**

Table A–22. Units 5 & 6 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	9,659	57.95	9,811	58.87	0.92	0	0
February	5.50	9,664	53.15	9,823	54.03	0.87	0	0
March	4.75	9,674	45.95	9,836	46.72	0.77	2,716	2,088
April	4.75	9,687	46.01	9,870	46.88	0.87	80,889	70,292
May	4.75	9,710	46.12	9,892	46.99	0.87	86,529	75,128
June	5.00	9,729	48.65	9,908	49.54	0.89	154,428	138,137
July	6.50	9,720	63.18	9,924	64.51	1.33	348,953	464,002
August	6.50	9,713	63.14	9,933	64.56	1.42	108,156	154,062
September	4.75	9,706	46.10	9,916	47.10	1.00	90,536	90,456
October	5.00	9,693	48.46	9,877	49.39	0.92	0	0
November	6.00	9,672	58.03	9,836	59.01	0.98	0	0
December	6.50	9,658	62.78	9,811	63.77	1.00	0	0
							Units 5 & 6 total	**994,165**

4.7 NET PRESENT COST

The Net Present Cost (NPC) of a wet cooling system retrofit at AGS is the sum of all annual expenditures over the project's 20-year life span discounted according to the year in which the expense is incurred and the selected discount rate. The NPC represents the total change in revenue streams, in 2007 dollars, that AGS can expect over 20 years as a direct result of converting to wet cooling towers. The following values were used to calculate the NPC at a 7 percent discount rate:

- *Capital and Start-up.* Includes all capital, indirect, contingency, and shutdown costs. All costs in this category are incurred in Year 0. (See Table A–16.)
- *Annual O&M.* Base cost values for Year 1 and Year 12 are adjusted for subsequent years using a 2 percent year-over-year escalator. Because AGS has a relatively low capacity utilization factor, O&M costs for the NPC calculation were estimated at 50 percent of their maximum value. (See Table A–17.)
- *Annual Energy Penalty.* Insufficient information is available to this study to forecast future generating output at AGS. In lieu of annual estimates, this study uses the net MWh output from 2006 as the calculation basis for Years 1 through 20. Wholesale prices include a year-over-year price escalator of 5.8 percent (based on the Producer Price Index). The energy penalty values are based on the increased fuel option discussed in Section 4.6. (See Table A– 20, Table A–21, and Table A–22.)

Using these values, the NPC_{20} for AGS is $263 million. Appendix C contains detailed annual calculations used to develop this cost.

4.8 ANNUAL COST

The annual cost incurred by AGS for a wet cooling tower retrofit is the sum of annual amortized capital costs plus the annual average of O&M and energy penalty expenditures. Capital costs are amortized at a 7 percent discount rate over 20 years. O&M and energy penalty costs are calculated in the same manner as for the NPC_{20} (Section 4.7). Revenue losses from a construction-related shutdown, if any, are incurred in Year 0 only and not included in the annual cost summarized in Table A–23.

Table A–23. Annual Cost

Discount Rate (%)	Capital Cost ($)	Annual O&M ($)	Annual energy penalty ($)	Annual cost ($)
7.00	19,800,000	2,100,000	3,500,000	**25,400,000**

4.9 COST-TO-GROSS REVENUE COMPARISON

Limited financial data are available to conduct a detailed analysis of the economic impact that a wet cooling system retrofit will have on AGS's annual revenues. The facility's gross annual revenue can be approximated using 2006 net generating data (CEC 2006) and average wholesale prices for electricity as recorded at the SP 15 trading hub (ICE 2006b). This estimate, therefore, does not reflect any changes that may result from different wholesale prices or contract agreements that may increase or decrease the gross revenue summarized below, nor does it account for annual fixed revenue requirements or other variable costs.

The estimate of gross annual revenue from electricity sales at AGS is a straightforward calculation that multiplies the monthly wholesale cost of electricity by the amount generated for the particular month. The estimated gross revenue for AGS is summarized in Table A–24. A comparison of annual costs to annual gross revenue is summarized in Table A–25.

Table A-24. Estimated Gross Revenue

	Wholesale price ($/MWh)	Net generation (MWh)			Estimated gross revenue ($)			
		Units 1 & 2	Units 3 & 4	Units 5 & 6	Units 1 & 2	Units 3 & 4	Units 5 & 6	AGS total
January	66	2,283	20,640	0	150,678	1,362,240	0	**1,512,918**
February	61	2,391	27,072	0	145,851	1,651,392	0	**1,797,243**
March	51	3,454	9,331	2,716	176,154	475,881	138,516	**790,551**
April	51	12,171	63,683	80,889	620,721	3,247,833	4,125,339	**7,993,893**
May	51	301	66,633	86,529	15,351	3,398,283	4,412,979	**7,826,613**
June	55	5,667	112,281	154,428	311,685	6,175,455	8,493,540	**14,980,680**
July	91	61,916	178,206	348,953	5,634,356	16,216,746	31,754,723	**53,605,825**
August	73	241	63,338	108,156	17,593	4,623,674	7,895,388	**12,536,655**
September	53	1,210	64,159	90,536	64,130	3,400,427	4,798,408	**8,262,965**
October	57	0	31,980	0	0	1,822,860	0	**1,822,860**
November	66	0	29,243	0	0	1,930,038	0	**1,930,038**
December	67	1,725	46,593	0	115,575	3,121,731	0	**3,237,306**
AGS total		**91,359**	**713,159**	**872,207**	**7,252,094**	**47,426,560**	**61,618,893**	**116,297,547**

Table A-25. Cost-Revenue Comparison

Estimated gross annual revenue ($)	Initial capital		O&M		Energy penalty		Total annual cost	
	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross
116,300,000	19,800,000	17	2,100,000	1.8	3,100,000	2.7	**25,000,000**	**21**

5.0 OTHER TECHNOLOGIES

Within the scope of this study, and using the OPC resolution's stated goal of reducing impingement and entrainment by 90–95 percent as a benchmark, the effectiveness of other technologies commonly used to address such impacts could not be conclusively determined for use at AGS. As with many existing facilities, the site's location and configuration complicate the use of some technologies that might be used successfully elsewhere. A more detailed analysis that also comprises a biological evaluation may determine the applicability of one or more of these technologies to AGS. A brief summary of these technologies' applicability follows.

5.1 MODIFIED RISTROPH SCREENS—FINE MESH

The principal concern with this technology is the successful return of viable organisms captured on the screens to the source water body. AGS currently withdraws its cooling water from Los Cerritos Channel, which primarily consists of water drawn through Alamitos Bay. Water within Los Cerritos Channel primarily flows towards AGS due to the action of the circulating water pumps. Returning any collected organisms to Los Cerritos Channel would be problematic because there is a high likelihood of reimpingement due to the flow patterns within the channel. Use of Alamitos Bay as the return location may address this concern, but potential obstacles remain over the long-term viability of fragile organisms (eggs and larvae) transported over the long distance from the facility to the bay. Discharging organisms to the San Gabriel River may also be problematic because of the elevated temperatures (90ºF and higher) that can dominate the near-discharge area (AGS and HnGS have the capacity to introduce over 2,000 mgd of elevated temperature water into this section of the San Gabriel River). Successful deployment of this technology might be feasible with a better understanding of the biological conditions in Los Cerritos Channel and Alamitos Bay.

5.2 BARRIER NETS

The entrance to the north and south intake canals is the beginning of each CWIS at AGS and the likely location for any deployment of a barrier net. At the junction with Los Cerritos Channel, the canals are approximately 150 feet wide, which should be sufficient area for a barrier net. The nature of flows within Los Cerritos Channel, however, makes deployment problematic. Storm events often produce heavy debris loads at AGS and could damage or destroy a barrier net in this location. For this reason, plus its ineffectiveness in reducing entrainment, barrier nets were not considered further in this study.

5.3 AQUATIC FILTRATION BARRIERS (AFBS)

AFBs require large areas of relatively clean, low turbulence water in which to function properly. To protect each intake canal, AGS would require two AFBs, each approximately 35,000 ft^2 in total area. The available space within Los Cerritos Channel, combined with the heavy debris issues identified for barrier nets, precludes the use of AFBs at AGS.

5.4 VARIABLE SPEED DRIVES

VSDs were not considered for analysis at AGS because the technology alone cannot be expected to achieve the desired level of reductions in impingement and entrainment, nor could it be combined with another technology to yield the desired reductions. Pumps that have been retrofitted with VSDs can reduce overall flow intake volumes by 10 to 35 percent over the current once-through configuration (US EPA, 2001). The actual reduction, however, will vary based on the cooling water demand at different times of the year. At peak demand, the pumps will essentially function as standard circulating water pumps and withdraw water at the maximum rated capacity, thus negating any potential benefit. Use of VSDs may be an economically desirable option when pumps are retrofitted or replaced for other reasons, but were not considered further for this study.

5.5 CYLINDRICAL FINE MESH WEDGEWIRE

Fine mesh cylindrical wedgewire screens have not been deployed or evaluated at coastal facilities for applications as large as would be required at AGS (approximately 1,100 mgd). To function as intended, cylindrical wedgewire screens must be submerged in a water body with a consistent ambient current of 0.5 fps. Ideally, this current is unidirectional so that screens may be oriented properly and any debris impinged on the screens will be carried downstream when the air-burst cleaning system is activated.

AGS currently withdraws cooling water from Los Cerritos Channel and, by extension, Alamitos Bay. Space constraints and navigation concerns prohibit the placement of any large cylindrical screens in the channel or bay, let alone the 12 to 14 84-inch diameter screens that would be required to supply the facility with adequate volumes of water. The only theoretical location available for AGS would be offshore in the Pacific Ocean, west of the entrance to Alamitos Bay. Limited information regarding the subsurface currents in the near-shore environment near Alamitos Bay is available. Data suggest that these currents are multi-directional depending on the tide and season and fluctuate in terms of velocity, with prolonged periods below 0.5 fps (SCCOOS, 2006). To attain sufficient depth (approximately 20 feet) and an ambient current that might allow deployment, screens would need to be located 2,000 feet or more offshore. Discussions with vendors who design these systems indicated that distances over 1,000 to 1,500 feet become problematic due to the inability of the air burst system to maintain adequate pressure for sufficient cleaning (Someah, 2007). Together, these considerations preclude further evaluation of fine mesh cylindrical wedgewire screens at AGS.

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Appendix A. Once-Through and Closed-Cycle Thermal Performance

		Units 1 & 2			Units 3 & 4			Units 5 & 6		
		Once through	Closed cycle	Net increase	Once through	Closed cycle	Net increase	Once through	Closed cycle	Net increase
JAN	Backpressure (in. HgA)	1.49	2.28	**0.79**	1.42	2.17	**0.75**	1.31	2.02	**0.70**
	Heat rate Δ (%)	*-0.22*	*0.91*	***1.12***	*-0.11*	*1.13*	***1.25***	*-0.22*	*0.85*	***1.08***
FEB	Backpressure (in. HgA)	1.55	2.35	**0.80**	1.48	2.24	**0.76**	1.37	2.08	**0.71**
	Heat rate Δ (%)	*-0.16*	*1.03*	***1.19***	*-0.04*	*1.26*	***1.30***	*-0.16*	*0.97*	***1.14***
MAR	Backpressure (in. HgA)	1.65	2.43	**0.78**	1.57	2.31	**0.74**	1.45	2.15	**0.70**
	Heat rate Δ (%)	*-0.06*	*1.16*	***1.22***	*0.09*	*1.39*	***1.31***	*-0.07*	*1.10*	***1.17***
APR	Backpressure (in. HgA)	1.76	2.64	**0.88**	1.68	2.52	**0.84**	1.56	2.35	**0.79**
	Heat rate Δ (%)	*0.09*	*1.52*	***1.43***	*0.25*	*1.75*	***1.50***	*0.07*	*1.46*	***1.38***
MAY	Backpressure (in. HgA)	1.93	2.79	**0.86**	1.84	2.66	**0.82**	1.71	2.48	**0.77**
	Heat rate Δ (%)	*0.33*	*1.75*	***1.41***	*0.53*	*1.98*	***1.45***	*0.31*	*1.69*	***1.38***
JUN	Backpressure (in. HgA)	2.06	2.90	**0.83**	1.96	2.76	**0.80**	1.83	2.57	**0.75**
	Heat rate Δ (%)	*0.54*	*1.90*	***1.36***	*0.75*	*2.14*	***1.38***	*0.51*	*1.85*	***1.34***
JUL	Backpressure (in. HgA)	2.00	3.01	**1.01**	1.90	2.87	**0.97**	1.77	2.68	**0.91**
	Heat rate Δ (%)	*0.44*	*2.06*	***1.62***	*0.65*	*2.30*	***1.65***	*0.41*	*2.01*	***1.60***
AUG	Backpressure (in. HgA)	1.96	3.08	**1.12**	1.86	2.93	**1.07**	1.73	2.73	**1.00**
	Heat rate Δ (%)	*0.37*	*2.14*	***1.77***	*0.57*	*2.37*	***1.80***	*0.35*	*2.10*	***1.75***
SEP	Backpressure (in. HgA)	1.90	2.96	**1.05**	1.81	2.81	**1.00**	1.68	2.62	**0.94**
	Heat rate Δ (%)	*0.29*	*1.98*	***1.69***	*0.48*	*2.22*	***1.73***	*0.27*	*1.93*	***1.66***
OCT	Backpressure (in. HgA)	1.81	2.69	**0.89**	1.72	2.56	**0.84**	1.60	2.39	**0.79**
	Heat rate Δ (%)	*0.15*	*1.59*	***1.44***	*0.33*	*1.83*	***1.50***	*0.13*	*1.53*	***1.40***
NOV	Backpressure (in. HgA)	1.63	2.43	**0.80**	1.55	2.31	**0.76**	1.44	2.15	**0.71**
	Heat rate Δ (%)	*-0.08*	*1.16*	***1.24***	*0.06*	*1.39*	***1.33***	*-0.08*	*1.10*	***1.19***
DEC	Backpressure (in. HgA)	1.48	2.28	**0.80**	1.41	2.17	**0.76**	1.31	2.02	**0.71**
	Heat rate Δ (%)	*-0.23*	*0.91*	***1.13***	*-0.12*	*1.13*	***1.26***	*-0.23*	*0.85*	***1.08***

Note: Heat rate delta represents change from design value calculated according to estimated ambient conditions for each month.

Appendix B. Itemized Capital Costs

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
CIVIL / STRUCTURAL / PIPING	--	--	--	--	--	--	--	--	--	--
Allocation for other accessories (bends, water hammers…)	lot	1	--	--	500,000	500,000	4,000.00	85	340,000	**840,000**
Allocation for pipe racks (approx 3100 ft) and cable racks	t	310	--	--	2,500	775,000	17.00	105	553,350	**1,328,350**
Allocation for sheet piling and dewatering	lot	1	--	--	500,000	500,000	5,000.00	100	500,000	**1,000,000**
Allocation for testing pipes	lot	1	--	--	--	--	2,000.00	95	190,000	**190,000**
Allocation for Tie-Ins to existing condenser's piping	lot	1	--	--	250,000	250,000	2,000.00	85	170,000	**420,000**
Allocation for trust blocks	lot	1	--	--	50,000	50,000	500.00	95	47,500	**97,500**
Backfill for PCCP pipe (reusing excavated material)	m3	27,202	--	--	--	--	0.04	200	217,616	**217,616**
Bedding for PCCP pipe	m3	5,275	--	--	25	131,875	0.04	200	42,200	**174,075**
Bend for PCCP pipe 24" diam (allocation)	ea	6	--	--	3,000	18,000	20.00	95	11,400	**29,400**
Bend for PCCP pipe 42" & 48" diam (allocation)	ea	18	--	--	5,000	90,000	25.00	95	42,750	**132,750**
Bend for PCCP pipe 72" diam (allocation)	ea	3	--	--	18,000	54,000	40.00	95	11,400	**65,400**
Bend for PCCP pipe 96" diam (allocation)	ea	4	--	--	30,000	120,000	75.00	95	28,500	**148,500**
Building architectural (siding, roofing, doors, painting…etc)	ea	3	--	--	250,000	750,000	3,000.00	75	675,000	**1,425,000**
Butterfly valves 120" c/w allocation for actuator & air lines	ea	4	252,000	1,008,000	--	--	80.00	85	27,200	**1,035,200**
Butterfly valves 30" c/w allocation for actuator & air lines	ea	56	30,800	1,724,800	--	--	50.00	85	238,000	**1,962,800**
Butterfly valves 48" c/w allocation for actuator & air lines	ea	7	46,200	323,400	--	--	50.00	85	29,750	**353,150**
Butterfly valves 54" c/w allocation for actuator & air lines	ea	8	60,900	487,200	--	--	55.00	85	37,400	**524,600**
Butterfly valves 60" c/w allocation for actuator & air lines	ea	6	75,600	453,600	--	--	60.00	85	30,600	**484,200**
Butterfly valves 72" c/w allocation for actuator & air lines	ea	10	96,600	966,000	--	--	75.00	85	63,750	**1,029,750**
Butterfly valves 84" c/w allocation for actuator & air lines	ea	10	124,600	1,246,000	--	--	75.00	85	63,750	**1,309,750**
Butterfly valves 96" c/w allocation for actuator & air lines	ea	8	151,200	1,209,600	--	--	75.00	85	51,000	**1,260,600**
Check valves 48"	ea	7	66,000	462,000	--	--	24.00	85	14,280	**476,280**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Check valves 60"	ea	2	108,000	216,000	--	--	30.00	85	5,100	**221,100**
Check valves 84"	ea	2	178,000	356,000	--	--	36.00	85	6,120	**362,120**
Check valves 96"	ea	2	216,000	432,000	--	--	40.00	85	6,800	**438,800**
Concrete barrier walls (all in)	m3	1,912	--	--	250	478,000	8.00	75	1,147,200	**1,625,200**
Concrete basin walls (all in)	m3	658	--	--	225	148,050	8.00	75	394,800	**542,850**
Concrete elevated slabs (all in)	m3	748	--	--	250	187,000	10.00	75	561,000	**748,000**
Concrete for transformers and oil catch basin (allocation)	m3	200	--	--	250	50,000	10.00	75	150,000	**200,000**
Concrete slabs on grade (all in)	m3	6,499	--	--	200	1,299,800	4.00	75	1,949,700	**3,249,500**
Ductile iron cement pipe 12" diam. for fire water line	ft	4,200	--	--	100	420,000	0.60	95	239,400	**659,400**
Excavation and backfill for fire line, blowdown & make-up (using excavated material for backfill except for bedding)	m3	22,472	--	--	--	--	0.08	200	359,552	**359,552**
Excavation for PCCP pipe	m3	48,849	--	--	--	--	0.04	200	390,792	**390,792**
Fencing around transformers	m	50	--	--	30	1,500	1.00	75	3,750	**5,250**
Flange for PCCP joints 24"	ea	12	--	--	1,725	20,700	14.00	95	15,960	**36,660**
Flange for PCCP joints 30"	ea	50	--	--	2,260	113,000	16.00	95	76,000	**189,000**
Flange for PCCP joints 72"	ea	2	--	--	9,860	19,720	25.00	95	4,750	**24,470**
Flange for PCCP joints 84"	ea	8	--	--	13,210	105,680	30.00	95	22,800	**128,480**
Flange for PCCP joints 96"	ea	4	--	--	15,080	60,320	35.00	95	13,300	**73,620**
Foundations for pipe racks and cable racks	m3	720	--	--	250	180,000	8.00	75	432,000	**612,000**
FRP flange 120"	ea	8	--	--	236,500	1,892,000	1,200.00	85	816,000	**2,708,000**
FRP flange 30"	ea	150	--	--	1,679	251,873	50.00	85	637,500	**889,373**
FRP flange 48"	ea	20	--	--	3,000	60,000	75.00	85	127,500	**187,500**
FRP flange 54"	ea	16	--	--	5,835	93,359	80.00	85	108,800	**202,159**
FRP flange 60'	ea	16	--	--	7,785	124,565	100.00	85	136,000	**260,565**
FRP flange 72"	ea	16	--	--	20,888	334,203	200.00	85	272,000	**606,203**
FRP flange 84"	ea	16	--	--	33,381	534,096	300.00	85	408,000	**942,096**
FRP flange 96"	ea	20	--	--	40,000	800,000	500.00	85	850,000	**1,650,000**
FRP pipe 120" diam.	ft	1,900	--	--	4,257	8,088,300	2.00	85	323,000	**8,411,300**
FRP pipe 60" diam.	ft	680	--	--	615	418,132	0.90	85	52,020	**470,152**
FRP pipe 84" diam.	ft	680	--	--	946	643,280	1.50	85	86,700	**729,980**
FRP pipe 96" diam.	ft	680	--	--	2,838	1,929,840	1.75	85	101,150	**2,030,990**
Harness clamp 24" c/w external testable joint	ea	60	--	--	1,715	102,900	14.00	95	79,800	**182,700**
Harness clamp 42" & 48" c/w internal testable joint	ea	340	--	--	2,000	680,000	16.00	95	516,800	**1,196,800**
Harness clamp 72" c/w internal testable joint	ea	20	--	--	2,440	48,800	18.00	95	34,200	**83,000**
Harness clamp 84" c/w internal testable joint	ea	500	--	--	2,845	1,422,500	20.00	95	950,000	**2,372,500**
Harness clamp 96" c/w internal testable joint	ea	80	--	--	3,300	264,000	22.00	95	167,200	**431,200**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Joint for FRP pipe 120" diam.	ea	100	--	--	22,562	2,256,210	1,200.00	85	10,200,000	**12,456,210**
Joint for FRP pipe 84" diam.	ea	20	--	--	5,014	100,276	300.00	85	510,000	**610,276**
Joint for FRP pipe 60" diam.	ea	20	--	--	1,797	35,948	100.00	85	170,000	**205,948**
Joint for FRP pipe 96" diam.	ea	20	--	--	17,974	359,480	600.00	85	1,020,000	**1,379,480**
PCCP pipe 24" dia. For blowdown	ft	1,200	--	--	98	117,600	0.50	95	57,000	**174,600**
PCCP pipe 42" dia. for blowdown	ft	400	--	--	195	78,000	0.90	95	34,200	**112,200**
PCCP pipe 48" dia. for make-up water line	ft	3,400	--	--	260	884,000	1.00	95	323,000	**1,207,000**
PCCP pipe 72" diam.	ft	400	--	--	507	202,800	1.30	95	49,400	**252,200**
PCCP pipe 84" diam.	ft	9,700	--	--	562	5,451,400	1.50	95	1,382,250	**6,833,650**
PCCP pipe 96" diam.	ft	1,600	--	--	890	1,424,000	2.00	95	304,000	**1,728,000**
Riser (FRP pipe 30" diam X55 ft)	ea	50	--	--	15,350	767,490	150.00	85	637,500	**1,404,990**
Structural steel for barrier wall	t	209	--	--	2,500	522,500	15.00	105	329,175	**851,675**
Structural steel for building	t	315	--	--	2,500	787,500	20.00	105	661,500	**1,449,000**
CIVIL / STRUCTURAL / PIPING TOTAL	**--**	**--**	**--**	**8,884,600**	**--**	**36,997,696**	**--**	**--**	**30,509,165**	**76,391,461**
DEMOLITION	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**
Filling up with granular material of 2 ponds measuring approximately 50 m X 50 m and assuming 5m deep.	m3	25,000	--	--	25	625,000	0.04	200	200,000	**825,000**
DEMOLITION TOTAL	**--**	**--**	**--**	**0**	**--**	**625,000**	**--**	**--**	**200,000**	**825,000**
ELECTRICAL	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**
4.16 kv cabling feeding MCC's	m	3,000	--	--	75	225,000	0.40	85	102,000	**327,000**
4.16kV switchgear - 4 breakers	ea	2	250,000	500,000	--	--	150.00	85	25,500	**525,500**
480 volt cabling feeding MCC's	m	1,500	--	--	70	105,000	0.40	85	51,000	**156,000**
480V Switchgear - 1 breaker 3000A	ea	9	30,000	270,000	--	--	80.00	85	61,200	**331,200**
Allocation for automation and control	lot	1	--	--	1,000,000	1,000,000	10,000.00	85	850,000	**1,850,000**
Allocation for cable trays and duct banks	m	3,555	--	--	75	266,625	1.00	85	302,175	**568,800**
Allocation for lighting and lightning protection	lot	1	--	--	150,000	150,000	1,500.00	85	127,500	**277,500**
Dry Transformer 2MVA xxkV-480V	ea	9	100,000	900,000	--	--	100.00	85	76,500	**976,500**
Lighting & electrical services for pump house building	ea	3	--	--	45,000	135,000	500.00	85	127,500	**262,500**
Local feeder for 2000 HP motor 4160 V (up to MCC)	ea	2	--	--	40,000	80,000	160.00	85	27,200	**107,200**
Local feeder for 250 HP motor 460 V (up to MCC)	ea	50	--	--	18,000	900,000	150.00	85	637,500	**1,537,500**
Local feeder for 4000 HP motor 4160 V (up to MCC)	ea	2	--	--	50,000	100,000	200.00	85	34,000	**134,000**
Local feeder for 6000 HP motor 4160 V (up to MCC)	ea	2	--	--	60,000	120,000	250.00	85	42,500	**162,500**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Oil Transformer 10/13.33MVA xx-4.16kV	ea	2	190,000	380,000	--	--	150.00	85	25,500	**405,500**
Oil Transformer 20MVA xx-4.16kV	ea	1	250,000	250,000	--	--	200.00	85	17,000	**267,000**
Primary breaker(xxkV)	ea	6	45,000	270,000	--	--	60.00	85	30,600	**300,600**
Primary feed cabling (assumed 13.8 kv)	m	6,000	--	--	175	1,050,000	0.50	85	255,000	**1,305,000**
ELECTRICAL TOTAL	**--**	**--**	**--**	**2,570,000**	**--**	**4,131,625**	**--**	**--**	**2,792,675**	**9,494,300**
MECHANICAL	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**
Allocation for ventilation of buildings	ea	3	100,000	300,000	--	--	1,000.00	85	255,000	**555,000**
Cooling tower for units 1 and 2	lot	1	6,400,000	6,400,000	--	--	--	--	--	**6,400,000**
Cooling tower for units 3 and 4	lot	1	9,800,000	9,800,000	--	--	--	--	--	**9,800,000**
Cooling tower for units 5 and 6	lot	1	14,700,000	14,700,000	--	--	--	--	--	**14,700,000**
Overhead crane 50 ton in (in pump house) Including additional structure to reduce the span	ea	3	500,000	1,500,000	--	--	1,000.00	85	255,000	**1,755,000**
Pump 4160 V 2000 HP	ea	2	1,000,000	2,000,000	--	--	500.00	85	85,000	**2,085,000**
Pump 4160 V 4000 HP	ea	2	1,600,000	3,200,000	--	--	800.00	85	136,000	**3,336,000**
Pump 4160 V 6000 HP	ea	2	1,800,000	3,600,000	--	--	1,100.00	85	187,000	**3,787,000**
MECHANICAL TOTAL	**--**	**--**	**--**	**41,500,000**	**--**	**0**	**--**	**--**	**918,000**	**42,418,000**

Appendix C. Net Present Cost Calculation

Project Year	Capital / Startup ($)	O & M ($)	Energy Penalty ($)			Total ($)	Annual Discount Factor	Present Value ($)
			Units 1 & 2	Units 3 & 4	Units 5 & 6			
0	209,800,000	--	--	--		209,800,000	1	**209,800,000**
1	--	1,600,400	130,877	801,230	994,165	3,526,672	0.9346	**3,296,028**
2	--	1,632,408	138,507	847,942	1,052,125	3,670,982	0.8734	**3,206,236**
3	--	1,665,056	146,582	897,377	1,113,464	3,822,479	0.8163	**3,120,290**
4	--	1,698,357	155,128	949,694	1,178,378	3,981,558	0.7629	**3,037,531**
5	--	1,732,324	164,172	1,005,062	1,247,078	4,148,636	0.713	**2,957,977**
6	--	1,766,971	173,743	1,063,657	1,319,783	4,324,153	0.6663	**2,881,183**
7	--	1,802,310	183,872	1,125,668	1,396,726	4,508,576	0.6227	**2,807,490**
8	--	1,838,357	194,592	1,191,294	1,478,155	4,702,398	0.582	**2,736,796**
9	--	1,875,124	205,937	1,260,747	1,564,331	4,906,139	0.5439	**2,668,449**
10	--	1,912,626	217,943	1,334,248	1,655,532	5,120,349	0.5083	**2,602,674**
11	--	1,950,879	230,649	1,412,035	1,752,049	5,345,612	0.4751	**2,539,700**
12	--	2,366,992	244,096	1,494,357	1,854,194	5,959,638	0.444	**2,646,079**
13	--	2,414,331	258,327	1,581,477	1,962,293	6,216,429	0.415	**2,579,818**
14	--	2,462,618	273,387	1,673,678	2,076,695	6,486,378	0.3878	**2,515,417**
15	--	2,511,870	289,326	1,771,253	2,197,766	6,770,215	0.3624	**2,453,526**
16	--	2,562,108	306,193	1,874,517	2,325,896	7,068,714	0.3387	**2,394,174**
17	--	2,613,350	324,044	1,983,801	2,461,496	7,382,692	0.3166	**2,337,360**
18	--	2,665,617	342,936	2,099,457	2,605,001	7,713,011	0.2959	**2,282,280**
19	--	2,718,929	362,929	2,221,855	2,756,873	8,060,587	0.2765	**2,228,752**
20	--	2,773,308	384,088	2,351,390	2,917,598	8,426,384	0.2584	**2,177,378**
Total								**263,269,138**

B. CONTRA COSTA POWER PLANT

MIRANT DELTA, LLC—ANTIOCH, CA

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1.0 GENERAL SUMMARY

Retrofitting the existing once-through cooling system at Contra Costa Power Plant (CCPP) with closed-cycle wet cooling towers is technically and logistically feasible based on this study's design criteria, and will reduce cooling water withdrawals from the San Joaquin River by approximately 95 percent. Impingement and entrainment impacts would be reduced by a similar proportion.

The preferred option selected for CCPP includes 2 conventional wet cooling towers (without plume abatement), with individual cells arranged in a back-to-back configuration to accommodate limited space at the site. This option would require temporary relocation of the main access road. Potential interference with the Unit 8 repowering project could not be evaluated. Space limitations would appear to preclude plume-abated towers in the design if they were required to mitigate visual impacts. Initial capital costs for the towers would also increase by a factor of 2 or 3.

Construction-related shutdowns are estimated to take approximately 4 weeks per unit (concurrent), although AGS is not expected to incur any financial loss as a result based on 2006 capacity utilization rates for all units.

The cooling tower configuration designed under the preferred option complies with all identified local use restrictions and includes necessary mitigation measures, where applicable.

1.1 COST

Initial capital and net present costs associated with installing and operating wet cooling towers at CCPP are summarized in Table B–1. Annualized costs based on 20-year average values for the various cost elements are summarized in Table B–2.

Table B–1. Cumulative Cost Summary

Cost category	Cost ($)	Cost per MWh (rated capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Total capital and start-up [a]	98,100,000	16.47	692
NPC_{20} [b]	104,300,000	17.51	736

[a] Includes all costs associated with the cooling tower construction and installation and shutdown loss, if any.
[b] NPC_{20} includes all capital costs, operation and maintenance costs, and energy penalty costs over 20 years discounted at 7 percent.

Table B–2. Annual Cost Summary

Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Capital and start-up	9,300,000	1.56	65.63
Operations and maintenance	500,000	0.08	3.53
Energy penalty	200,000	0.03	1.41
Total CCPP annual cost	**10,000,000**	**1.67**	**70.57**

1.2 ENVIRONMENTAL

Environmental changes associated with a cooling tower retrofit for CCPP are summarized in Table B–3 and discussed further in Section 3.4.

Table B–3. Environmental Summary

		Unit 6	Unit 7
Water use	Design intake volume (gpm)	149,800	149,800
	Cooling tower makeup water (gpm)	7,000	7,000
	Reduction from capacity (%)	95	95
Energy efficiency [a]	Summer heat rate increase (%)	0.56	0.56
	Summer energy penalty (%)	1.91	1.91
	Annual heat rate increase (%)	0.76	0.76
	Annual energy penalty (%)	2.11	2.11
Direct air emissions [b]	PM_{10} emissions (tons/yr) (maximum capacity)	86.30	86.30
	PM_{10} emissions (tons/yr) (2006 capacity utilization)	0.77	3.34

[a] Reflects the comparative increase between once-through and wet cooling systems, but does not account for any operational changes to address the change in efficiency, such as increased fuel consumption (see Section 4.6).

[b] Reflects emissions from the cooling tower only; does not include any increase in stack emissions.

1.3 OTHER POTENTIAL FACTORS

None.

2.0 BACKGROUND

Contra Costa Power Plant (CCPP) is a natural gas–fired steam electric generating facility located in an unincorporated section of the city of Contra Costa, Contra Costa County, owned and operated by Mirant Delta, LLC. The facility site is in the Sacramento/San Joaquin Delta on the southern bank of the San Joaquin River west of the Antioch Bridge. CCPP currently operates two steam generating units (Unit 6 and Unit 7). Units 1–5 have been retired from service, although Unit 3 and Unit 4 are used as synchronous condensers only and do not generate electricity for sale. The former Unit 8 project has since been transferred from Mirant Delta to Pacific Gas and Electric (PG&E) and is now known as the Gateway Generating Station (GGS) project. The GGS project is not part of this study. (See Table B–4 and Figure B–1.)

Table B–4. General Information

Unit	In-service year	Rated capacity (MW)	2006 capacity utilization [a]	Condenser cooling water flow (gpm)
Unit 6	1964	340	0.8%	160,500
Unit 7	1964	340	3.8%	160,500
CCPP total		**680**	**2.3%**	**321,000**

[a] *Quarterly Fuel and Energy Report—2006* (CEC 2006).

Figure B–1. General Vicinity of Contra Costa Power Plant

2.1 COOLING WATER SYSTEM

CCPP operates one cooling water intake structure (CWIS) to provide condenser cooling water to Unit 6 and Unit 7 (Figure B–2). Once-through cooling water is combined with low-volume wastes generated by CCPP and discharged to the San Joaquin River through a 300-foot constructed canal. Surface water withdrawals and discharges are regulated by NPDES Permit CA0004863, as implemented by Central Valley Regional Water Quality Control Board (CVRWQCB) Order 5-01-107.

Cooling water for Unit 6 and Unit 7 is withdrawn from the San Joaquin River through a surface intake structure that is flush with the shoreline. The CWIS comprises six screen bays, each fitted with a vertical traveling screen with 3/8-inch mesh panels. Three screen bays serve each unit. Screens are rotated once every 4 hours, or based on the pressure differential between the upstream and downstream faces of the screen. A high-pressure spray removes any debris or fish that have become impinged on the screen face. Captured debris is collected in a sump and returned to the estuary.

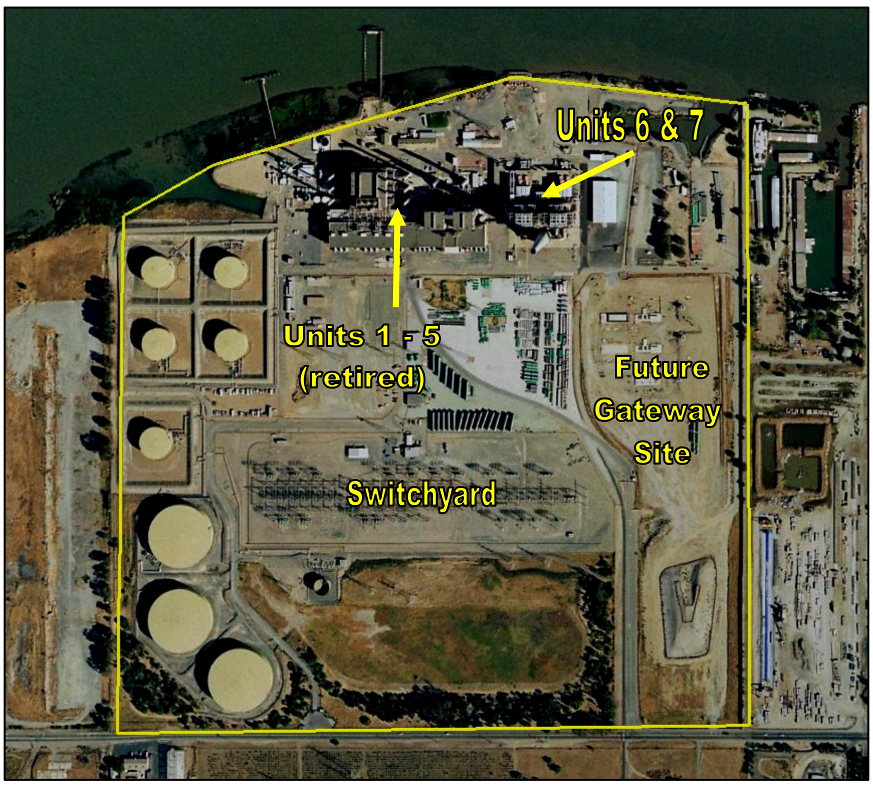

Figure B–2. Site View

After passing through the screens, the water flow diverges into two separate channels. Four variable frequency drive (VFD) pumps, two for each unit, draw water from the channels to the surface condensers. The pumps for Unit 6 and Unit 7 are each rated at 76,400 gallons per minute (gpm), or 110 million gallons per day (mgd), but are capable of operating at 50 percent of the maximum capacity. The maximum rated pumping capacity for Unit 5 and Unit 6 is 321,000 gpm, or 462 mgd (Mirant Delta 2006). Operation of the VFDs is governed by facility protocols that state the following:

> …from May 1 to July 15, a feed forward curve controls the circulating water pump (CWP) speed at 50% speed until 172 MW is achieved. The speed then gradually ramps to 95% speed at 322 MW. The speed is maintained at 95% through a full load of 345 MW. A discharge temperature set point of 85° F also cascades into the control logic to increase or decrease the pump speed as needed. (Mirant Delta 2006)

At maximum capacity, CCPP maintains a total pumping capacity rated at 441 mgd, with a condenser flow rating of 431 mgd (a portion is used for bearing cooling). On an annual basis, CCPP withdraws substantially less than its design capacity due to its low generating capacity utilization. When in operation and generating the maximum load, CCPP can be expected to withdraw water from the San Joaquin River at a rate approaching its maximum capacity.

2.2 SECTION 316(B) PERMIT COMPLIANCE

The CWIS currently in operation for Unit 5 and Unit 6 uses pumps fitted with VFDs that can reduce the intake flow volume by as much as 50 percent, depending on each unit's operating load, water temperatures, and other limits set in the control logic. This is particularly beneficial during sensitive spawning and migratory periods in the Sacramento/San Joaquin Delta region. At Contra Costa, this period extends from February through July, when larval stages for protected species, such as the Delta smelt, are most abundant. No information was available to evaluate the VFDs' actual operations and the relative changes in intake volume they provide compared with single-speed pumps. In 2006, 70 percent of the Unit 6 and Unit 7 net output coincided with the February to July period (CEC 2006).

Apart from the VFDs, Unit 6 and Unit 7 do not currently use other technologies or operational measures that are generally considered to be effective at reducing impingement and entrainment impacts. CVRWQCB Order 5-01-107 notes that, in 1986, the former owner, Pacific Gas and Electric (PG&E), implemented a Resources Management Plan to comply with best technology available (BTA) requirements under Clean Water Act (CWA) Section 316(b). The plan required PG&E to stock striped bass fish hatcheries in the Sacramento/San Joaquin Delta and improve its facility's intake structures. Operations are also coordinated with Mirant Delta's Pittsburg Power Plant located 7 miles west of the facility, including preferential dispatch of Pittsburg's Unit 7.

Because of its potential to take protected aquatic species, such as Delta smelt and Chinook salmon, Mirant Delta is required by the current order to develop a comprehensive conservation program (CP) in consultation with the U.S. Fish and Wildlife Service, National Marine Fisheries Service, and California Department of Fish and Game. The CP required the installation of an aquatic filtration barrier (AFB) if a concurrent pilot evaluation at CCPP proved effective (the evaluation at CCPP was later discontinued). Mirant is also a participant in the Bay Delta Conservation Plan, which aims to develop a comprehensive conservation and restoration framework that will be compliant with the California Endangered Species Act (CESA) and the federal Endangered Species Act (ESA).

The order does not contain any numeric or narrative limitations regarding impingement or entrainment resulting from CWIS operation, but does require CCPP to implement the Resources Management Plan. No information from the CVRWQCB is available indicating how it intends to proceed with the permit requirements in light of the changes to the Phase II rule.

3.0 WET COOLING SYSTEM RETROFIT

3.1 OVERVIEW

This study evaluates saltwater cooling towers as a retrofit option at CCPP, with the current source water (San Joaquin River) continuing to provide makeup water to the facility. Converting the existing once-through cooling system to wet cooling towers will reduce the facility's current intake capacity by approximately 95 percent; rates of impingement and entrainment will decline by a similar proportion. Use of reclaimed water was considered for CCPP but not analyzed in detail because the available volume cannot serve as a replacement for once-through cooling water. The proximity of available sources, however, may make reclaimed water an attractive alternative as makeup water for a wet cooling tower system when considering additional benefits its use may provide, such as avoidance of conflicts with effluent limitations or air emission standards.

The wet cooling towers' configuration—their size, arrangement, and location—was based on best professional judgment (BPJ) using the criteria outlined in Chapter 5, and designed to meet the performance benchmarks in the most cost-effective manner. Information not available to this study that offers a more complete facility characterization may lead to different conclusions regarding the cooling towers' physical configuration.

This study developed a conceptual design of wet cooling towers sufficient to meet each active generating unit's cooling demand at its rated output during peak climate conditions. Cost estimates are based on vendor quotes developed using the available information and the various design constraints identified at CCPP.

The overall practicality of retrofitting both units at CCPP will require an evaluation of factors outside the scope of this study, such as each unit's age and efficiency and its role in the overall reliability of electricity production and transmission in California, particularly the San Francisco Bay region.

3.2 DESIGN BASIS

3.2.1 CONDENSER SPECIFICATIONS

For this study, the wet cooling tower conceptual design selected for CCPP is based on the assumption that the condenser flow rate and thermal load to each will remain unchanged from the current system. Although no provision is included to re-optimize the condenser performance for service with a cooling tower, some modifications to the condenser (tube sheet and water box reinforcement) may be necessary to handle the increased water pressures that will result from the increased total pump head required to raise water to the cooling tower riser elevation.[1] The practicality and difficulty of these modifications are dependent on each unit's age and configuration but are assumed to be feasible at CCPP. Condenser water boxes for both units are

[1] In this context, re-optimization refers to a comprehensive overhaul of the condenser, such as re-tubing or converting the flow from single to multiple passes. Modifications are generally limited to reinforcement measures to enable the condenser to withstand the increased pressures.

located at grade level and appear to be readily accessible. Additional costs for condenser modifications are included in the discussion of capital expenditures (Section 4.3).

Information provided by CCPP was largely used as the basis for the cooling tower design. In some cases, the data were incomplete or conflicted with values obtained from other sources. Where possible, questionable values were verified or corrected using other known information about the condenser.

Parameters used in the development of the cooling tower design are summarized in Table B–5.

Table B–5. Condenser Design Specifications

	Unit 6	Unit 7
Thermal load (MMBTU/hr)	1,450	1,450
Surface area (ft^2)	135,000	135,000
Condenser flow rate (gpm)	149,800	149,800
Tube material	Aluminum brass	Aluminum brass
Heat transfer coefficient (BTU/hr•ft^2•°F)	587	587
Cleanliness factor	0.85	0.85
Inlet temperature (°F)	63	63
Temperature rise (°F)	19.37	19.37
Steam condensate temperature (°F)	91.7	91.7
Turbine exhaust pressure (in. HgA)	1.5	1.5

3.2.2 AMBIENT ENVIRONMENTAL CONDITIONS

CCPP is located in Contra Costa County along the southern shoreline of Suisun Bay in the Sacramento/San Joaquin Delta. Cooling water is withdrawn at the surface from a shoreline intake structure. Inlet temperature data specific to CCPP were not provided by Mirant Delta. As a substitute, monthly temperature data from the California Department of Water Resources Antioch Monitoring Station (ANH) were used in relevant calculations (DWR 2006).

The wet bulb temperature used to develop the overall cooling tower design was obtained from American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) publications. Data for the Contra Costa region indicate a 1 percent ambient wet bulb temperature of 66° F (ASHRAE 2006). A 12° F approach temperature was selected based on the site configuration and vendor input. At the design wet bulb and approach temperatures, the cooling towers will yield “cold” water at 78° F.

Monthly maximum wet bulb temperatures used in the development of energy penalty estimates in Section 4.6 were calculated using data obtained from the National Climatic Data Center (NCDC) monitoring station for Antioch, CA (NCDC 2006). Climate data used in this analysis are summarized in Table B–6.

Table B–6. Surface Water and Ambient Wet Bulb Temperatures

	Surface (°F)	Ambient wet bulb (°F)
January	50.0	50.7
February	52.7	52.8
March	58.3	55.3
April	61.5	56.6
May	64.6	59.4
June	67.0	63.0
July	72.3	66.0
August	71.8	64.3
September	70.2	61.3
October	65.2	57.3
November	58.6	55.5
December	51.9	54.5

3.2.3 LOCAL USE RESTRICTIONS

3.2.3.1 NOISE

Industrial development at CCPP is regulated by the Contra Costa General Plan, although the proximity to the city of Antioch warrants consideration of that city's applicable policies when actions may conflict with permitted uses. Both plans outline narrative criteria to be used as a guide for future development. Restrictions would be based on the site's zoning designation according to the Contra Costa General Plan and community noise equivalent levels (CNELs) measured near single-family residences. The cooling towers design for CCPP will have noise levels no greater than 60 dBA measured at 1,500 feet. The nearest residential areas are located more than 2,000 feet from the siting location. Accordingly, the wet cooling towers designed for CCPP do not include noise abatement measures such as low-noise fans or barrier walls.

3.2.3.2 BUILDING HEIGHT

The developed portion of CCPP is located within the heavy industry (HI) zone, according to the Contra Costa General Plan. This zone is dedicated to industrial uses and does not have a restriction with regard to structural height. Given the existing height of the current structures at CCPP and the proximity of residential and public recreational areas, this study selected a height restriction of 60 feet above grade level. The height of the wet cooling towers designed for CCPP, from grade level to the top of the fan deck, is 56 feet.

3.2.3.3 PLUME ABATEMENT

Local zoning ordinances do not contain any specific criteria for addressing any impact associated with a wet cooling tower plume.

The Contra Costa Unit 8 project, as originally designed, would have used a conventional (not plume-abated) cooling tower. Using the selection criteria for this study, plume abatement measures were not considered for CCPP; all towers are of a conventional design. The Final Staff Assessment (FSA) for the Contra Costa Unit 8 project noted disagreement between the California Energy Commission (CEC) and Mirant Delta over the significance of the wet cooling tower visual plume, but did not include any explicit findings of impact. A reference is made requiring the facility to mitigate any plume-related issues arising on local roads but does not make any specific determinations regarding public safety hazards, particularly as they may relate to Antioch Bridge. With respect to plume abatement, this study follows the design conditions from the original Unit 8 project and develops a conventional wet cooling tower configuration for CCPP (CEC 2001).

Community standards for assessing the visual impact associated with a cooling tower plume cannot be determined within the scope of this study. The proximity of nearby residential and commercial areas and the potential impact on the Sacramento/San Joaquin Delta viewshed, when considered in the context of CEC siting guidelines, may contribute to the selection of an alternate design if a wet cooling tower retrofit is undertaken at CCPP in the future. These guidelines assess the total size and persistence of a visual plume with respect to aesthetic standards for bay/delta resources. Significant visual changes resulting from the plume may warrant incorporation of plume abatement measures. Installing plume-abated cooling towers at CCPP will result in a different configuration (inline instead of back to back) and will require additional space. Space constraints may limit the configurations available for plume-abated towers. A final determination will be made with a better understanding of the boundaries and layout of the GGS project.

3.2.3.4 DRIFT AND PARTICULATE EMISSIONS

Drift elimination measures that are considered best available control technology (BACT) are required for all cooling towers evaluated in this study, regardless of their location. State-of-the-art drift eliminators are included for each cooling tower cell at CCPP, with an accepted efficiency of 0.0005 percent. Because cooling tower PM_{10} emissions are a function of the drift rate, drift eliminators are also considered BACT for PM_{10} emissions from wet cooling towers. This efficiency can be verified by a proper in situ test, which accounts for site-specific climate, water, and operating conditions. Testing based on the Cooling Tower Institute's Isokinetic Drift Test Code is required at initial start-up on only one representative cell of each tower, for an approximate cost of $60,000 per test, or approximately $120,000 for both cooling towers at CCPP (CTI 1994). This cost is not itemized in the final analysis and is instead included as part of the indirect cost estimate (Section 4.3).

3.2.3.5 FACILITY CONFIGURATION AND AREA CONSTRAINTS

The existing site's configuration does not present significant challenges to identifying a location for conventional cooling towers, although the selected location results in long distances between the towers and their respective generating units. As shown in Figure B–3, the property's total area is fairly compact and generally developed, with few areas located close to residential or commercial areas.

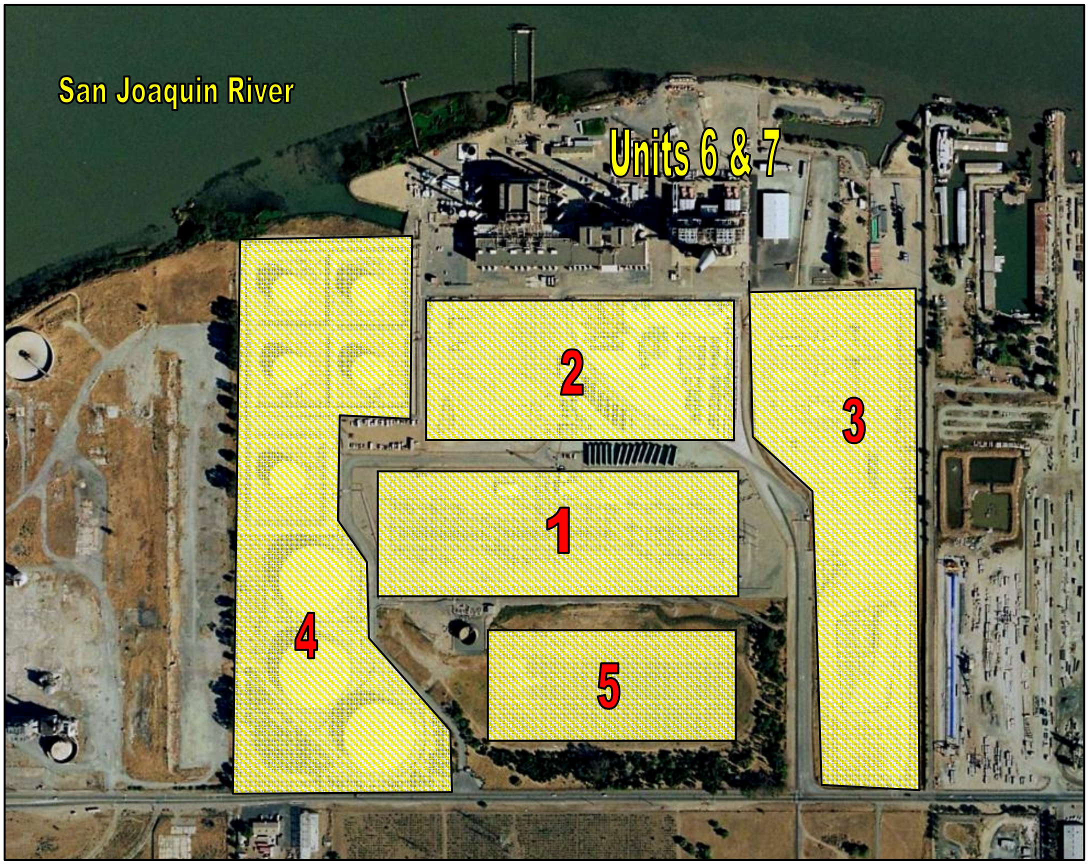

Figure B–3. Cooling Tower Siting Locations

Area 1 is the location of the PG&E switchyard. This study did not consider relocation of switchyards to accommodate cooling towers.

Area 2 is currently unoccupied by large structures, but appears to be used as a laydown area for construction of the GGS (Area 3). Use of this area would require reconfiguring an access and relocating construction staging activities to another location. Placement in this area is preferred because of its proximity to the generating units, but it is unclear how much of this area will be reserved for the GGS site after construction is completed. If this area is available, significantly less piping would be required than for other areas. In this location, supply and return pipe distances for each tower would be approximately 1,000 feet (2,000 feet total for both towers).

Area 4 is currently occupied by active fuel storage tanks. Removal and relocation cannot be evaluated in this study because of the complexity and cost.

Area 5 is currently unoccupied and borders the southern property line along Wilbur Avenue. The area does not appear to present any significant challenges to its use. No residential or commercial areas are nearby; agricultural operations are located across Wilbur Avenue, but would not experience any negative impacts related to noise or visual impairment. Use of Area 5 places the cooling towers at a substantial distance from their respective generating units and increases the overall piping and pump costs. In contrast to Area 2, which would require 2,000 feet total of piping, Area 5 would require 9,000 feet of large-diameter piping for both towers.

Based on the information available, this study selected Area 5 as the most practical location to accommodate two wet cooling towers for CCPP.

3.3 CONCEPTUAL DESIGN

Based on the design constraints discussed above, two wet cooling towers were selected to replace the current once-through cooling system that serves Unit 6 and Unit 7 at CCPP. Each unit will be served by an independently functioning tower with separate pump houses and pumps. Both towers at CCPP consist of conventional cells arranged in a multicell, back-to-back configuration.

3.3.1 SIZE

Each tower is constructed over a concrete collection basin 4 feet deep. The basin is larger than the tower structure's footprint, extending an additional 4 feet in each direction. The concrete used for construction is suitable for saltwater applications. The principal tower material is fiberglass reinforced plastic (FRP), with stainless steel fittings. These materials are more resistant to the higher corrosive effects of saltwater.

The size of each tower is primarily based on the thermal load rejected to the tower by the surface condenser and a 12° F approach to the ambient wet bulb temperature. Flow rates through each condenser remain unchanged.

General characteristics of the wet cooling towers selected for CCPP are summarized in Table B–7.

Table B–7. Wet Cooling Tower Design

	Tower 1 (Unit 6)	Tower 2 (Unit 7)
Thermal load (MMBTU/hr)	1,450	1,450
Circulating flow (gpm)	149,800	149,800
Number of cells	12	12
Tower type	Mechanical draft	Mechanical draft
Flow orientation	Counterflow	Counterflow
Fill type	Modular splash	Modular splash
Arrangement	Back to back	Back to back
Primary tower material	FRP	FRP
Tower dimensions (l x w x h) (ft)	324 x 96 x 56	324 x 96 x 56
Tower footprint with basin (l x w) (ft)	328 x 100	328 x 100

3.3.2 LOCATION

The initial site selection for each tower was based on the desire to locate each tower as close as possible to its respective generating unit to minimize the supply and return pipe distances and any increases in total pump head and brake horsepower. At CCPP, the linear distance between the generating units and towers is significant and impacts the overall cost of the project (Figure B–4).

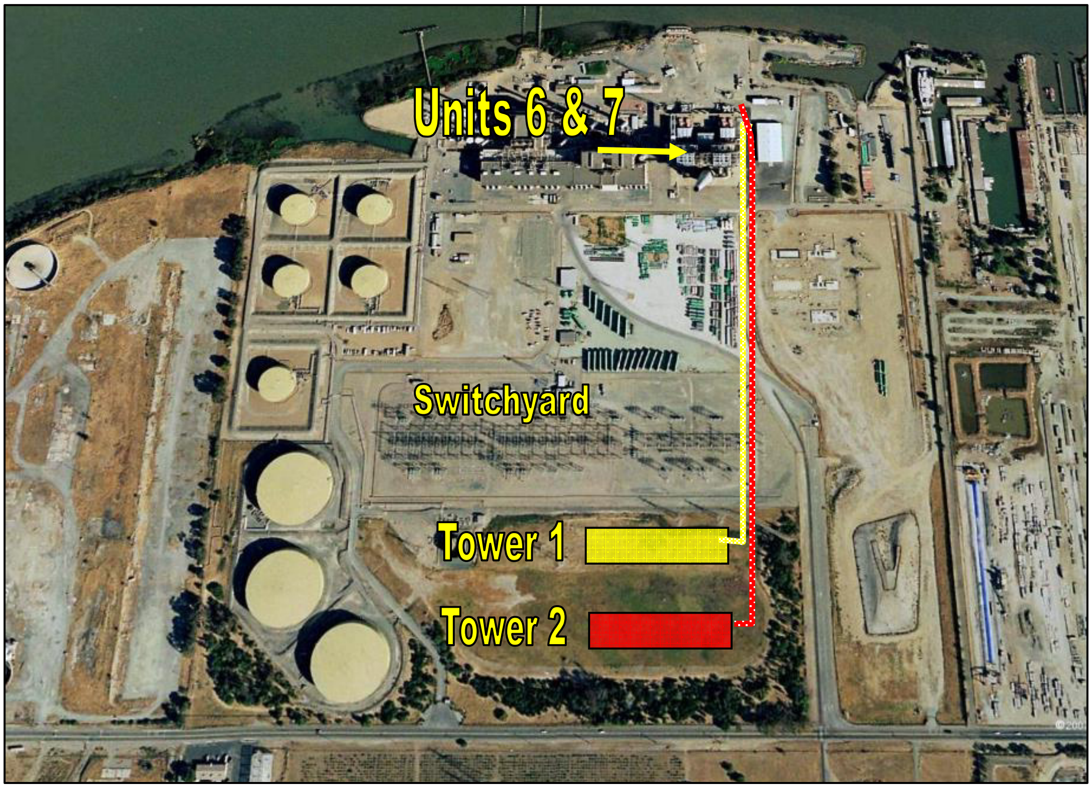

Figure B–4. Cooling Tower Locations

3.3.3 PIPING

The main supply and return pipelines to and from both towers will be located underground and made of prestressed concrete cylinder pipe (PCCP) suitable for saltwater applications. These pipes range in size from 72 to 84 inches in diameter. Pipes connecting the condensers to the supply and return lines are made of FRP and placed above ground on pipe racks. Above-ground placement avoids the potential disruption that may be caused by excavation in and around the power block. The condensers at CCPP are all located at grade level, enabling a relatively straightforward connection.

All riser piping (extending from the foot of the tower to the level of water distribution) is constructed of FRP.

Potential interference with underground obstacles and infrastructure is a concern, particularly at existing sites that are several decades old and have been substantially modified or rebuilt in the interim. Avoidance of these obstacles is considered to the degree practical in this study. Associated costs are included in the contingency estimate and are generally higher than similar estimates for new facilities (Section 4.3).

Appendix B details the total quantity of each pipe size and type for CCPP.

3.3.4 FANS AND PUMPS

Each tower cell uses an independent single-speed fan. The fan size and motor power are the same for each cell in each tower.

This analysis includes new pumps to circulate water between the condensers and cooling towers. Pumps are sized according to the flow rate for each tower, the relative distance between the towers and condensers, and the total head required to deliver water to the top of each cooling tower riser. A separate, multilevel pump house is constructed for each tower and sized to accommodate the motor control centers (MCCs) and appropriate electrical switchgear. The electrical installation includes all necessary transformers, cabling, cable trays, lighting, and lightning protection. A 50-ton overhead crane is also included to allow for pump servicing.

Fan and pump characteristics associated with wet cooling towers at CCPP are summarized in Table B–8. The net electrical demand of fans and new pumps is discussed further as part of the energy penalty analysis in Section 4.6.

Table B–8. Cooling Tower Fans and Pumps

		Tower 1 (Unit 6)	Tower 2 (Unit 7)
Fans	Number	12	12
	Type	Single speed	Single speed
	Efficiency	0.95	0.95
	Motor power (hp)	211	211
Pumps	Number	2	2
	Type	50% recirculating Mixed flow Suspended bowl Vertical	50% recirculating Mixed flow Suspended bowl Vertical
	Efficiency	0.88	0.88
	Motor power (hp)	2,205	2,205

3.4 ENVIRONMENTAL EFFECTS

Converting the existing once-through cooling system at CCPP to wet cooling towers will significantly reduce the intake of brackish water from the San Joaquin River and will presumably reduce impingement and entrainment by a similar proportion. Because closed-cycle systems will almost always result in condenser cooling water temperatures higher than those found in a comparable once-through system, wet towers will increase the operating heat rates at both of CCPP's steam units, thereby decreasing the facility's overall efficiency. Additional power will also be consumed by the tower fans and circulating pumps.

Depending on how CCPP chooses to address this change in efficiency, total stack emissions may increase for pollutants such as PM_{10}, SO_x, and NO_x, and may require additional control measures (e.g., electrostatic precipitation, flue gas desulfurization, and selective catalytic reduction) or the purchase of emission credits to meet air quality regulations. The availability of emission reduction credits (ERCs) and their associated cost was not evaluated as part of this study. Both factors, however, may limit the air emission compliance options available to CCPP.

No control measures are currently available for CO_2 emissions, which will increase, on a per--kWh basis, by the same proportion as any change in the heat rate. The towers themselves will constitute an additional source of PM_{10} emissions, the annual mass of which will largely depend on the capacity utilization rate for the generating units served by each tower.

If CCPP retains its National Pollutant Discharge Elimination System (NPDES) permit to discharge wastewater to the San Joaquin River with a wet cooling tower system, it may have to address revised effluent limitations resulting from the substantial change in the discharge quantity and characteristics. Thermal impacts from the current once-through system, if any, will be minimized with a wet cooling system.

3.4.1 AIR EMISSIONS

CCPP is located in the San Francisco Bay Area air basin. Air emissions are permitted by the Bay Area Air Quality Management District (BAAQMD) (Facility ID A0018).

Drift volumes are expected to be within the range of 0.5 gallons for every 100,000 gallons of circulating water in the towers. At CCPP, this corresponds to a rate of approximately 1.6 gpm based on the maximum combined flow from both towers. Because the area selected for wet cooling towers is downwind from sensitive structures with respect to the prevailing wind direction, salt drift deposition is not likely to be a significant concern from the cooling towers. Agricultural operations are located south of the facility but are unlikely to be impacted.

Total PM_{10} emissions from the CCPP cooling towers are a function of the number of hours in operation, overall water quality in the tower, and evaporation rate of drift droplets prior to deposition on the ground. Makeup water at CCPP will be obtained from the same source currently used for once-through cooling water (San Joaquin River). Water in this area of the Sacramento/San Joaquin Delta is heavily influenced by freshwater inflows from the San Joaquin River, but is also affected by tidal cycles in the delta region and seasonal impoundments and releases upstream. Water is considered to be brackish, with salinity levels varying by season and tide. For the purposes of this study, cooling towers were developed based on marine total dissolved solids (TDS) concentrations. At 1.5 cycles of concentration and assuming an initial TDS value of 35 parts per thousand (ppt), the water within the cooling towers will reach a maximum TDS level of roughly 53 ppt. Any drift droplets exiting the tower will have the same TDS concentration.

The cumulative mass emission of PM_{10} from CCPP will increase as a result of the direct emissions from the cooling towers themselves. Stack emissions of PM_{10}, as well as SO_x, NO_x, and other pollutants, will increase due to the drop in fuel efficiency, although the cumulative increase will depend on actual operations and emission control technologies currently in use. Maximum drift and PM_{10} emissions from the cooling towers are summarized in Table B–9.

Data summarizing the total facility emissions for these pollutants in 2005 are presented in Table B–10 (CARB 2005). In 2005, CCPP operated at an annual capacity utilization rate of 5.5 percent. Using this rate, the additional PM_{10} emissions from the cooling towers would increase the facility total by approximately 9.5 tons/year, or 180 percent.[2]

Table B–9. Full Load Drift and Particulate Estimates

	PM_{10} (lbs/hr)	PM_{10} (tons/year)	Drift (gpm)	Drift (lbs/hr)
Tower 1	20	86	0.8	375
Tower 2	20	86	0.8	375
Total CCPP PM_{10} and drift emissions	**40**	**172**	**1.6**	**750**

Table B–10. 2005 Emissions of SO_x, NO_x, PM_{10}

Pollutant	Tons/year
NO_x	26.2
SO_x	1.1
PM_{10}	5.3

3.4.2 MAKEUP WATER

The volume of makeup water required by both cooling towers at CCPP is the sum of evaporative loss and the blowdown volume required to maintain the circulating water in each tower at the design TDS concentration. Drift expelled from the towers represents an insignificant volume by comparison and is accounted for by rounding up evaporative loss estimates. Makeup water volumes are based on design conditions, and may fluctuate seasonally depending on climate conditions and facility operations. Wet cooling towers will reduce once-through cooling water withdrawals from Suisun Bay by approximately 96 percent over the current design intake capacity (Table B–11).

[2] 2006 emission data are not currently available from the Air Resources Board Web site. For consistency, the comparative increase in PM_{10} emissions estimated here is based on the 2005 CCPP capacity utilization rate instead of the 2006 rate presented in Table B–4. All other calculations in this chapter use the 2006 value.

Table B-11. Makeup Water Demand

	Tower circulating flow (gpm)	Evaporation (gpm)	Blowdown (gpm)	Total makeup water (gpm)
Tower 1	149,800	2,400	4,800	**7,200**
Tower 2	149,800	2,400	4,800	**7,200**
Total CCPP makeup water demand	**299,600**	**4,800**	**9,600**	**14,400**

One circulating water pump, rated at 76,400 gpm, which is currently used to provide once-through cooling water to the facility, will be retained in a wet cooling system to provide makeup water to each cooling tower. The retained pump's capacity exceeds the makeup demand by approximately 62,000 gpm. Any excess capacity will be routed through a bypass conduit and returned to the wet well at a point located behind the intake screens. Recirculating the excess capacity in this manner reduces additional cost that would be incurred if new pumps were required while maintaining the desired flow reduction. The intake of new water, measured at the intake screens, will be equal to the cooling towers' makeup water demand. Figure B–5 presents a schematic of this configuration.

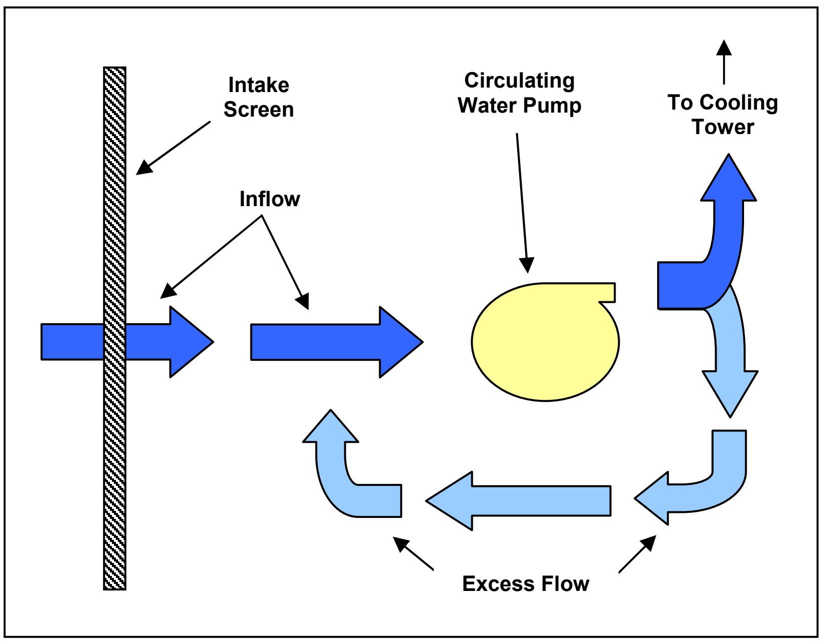

Figure B–5. Schematic of Intake Pump Configuration

The existing once-through cooling system at CCPP does not treat water withdrawn from Suisun Bay, with the exception of screening for debris and larger organisms and periodic chlorination to control biofouling in the condenser tubes and intake conduits. Conversion to a wet cooling tower system will not interfere with chlorination operations.

Makeup water will continue to be withdrawn from the San Joaquin River.

The wet cooling tower system proposed for CCPP includes water treatment for standard operational measures, i.e., corrosion inhibitors, biocides, and antiscaling agents. An allowance for these additional chemical treatments is included in annual operations and maintenance (O&M) costs. It is assumed that the current once-through cooling water quality will be acceptable for use in a seawater cooling tower (with continued screening and chlorination) and will not require any pretreatment to enable its use.

3.4.3 NPDES PERMIT COMPLIANCE

At maximum operation, wet cooling towers at CCPP will result in an effluent discharge of approximately 13 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, floor drain wastes, and cleaning wastes. These low-volume wastes may add an additional 0.5 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, CCPP will be required to modify its existing individual wastewater discharge (NPDES) permit.

Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0004863, as implemented by CVRWQCB Order R-01-107. All once-through cooling water and process wastewaters are discharged through a shoreline outfall to the San Joaquin River. The existing order contains effluent limitations based on the California Toxics Rule (CTR) and the1972 Thermal Plan and the Sacramento and San Joaquin River Basins Water Quality Control Plan ("Basin Plan").

CCPP will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities (40 CFR 423.13(d)(1)). These ELGs set numeric limitations for chromium and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity). Because ELGs are technology-based limitations, mixing zones or dilution factors are not applicable when determining compliance; limits must be met at the point of discharge from the cooling tower prior to commingling with any other waste stream. ELGs for cooling tower blowdown target priority pollutants that are contributed by maintenance chemicals and do not apply when limits may be exceeded as a result of background concentrations or other sources. Further discussion can be found in Chapter 4, Section 3.6.

Conversion to wet cooling towers will alter the volume and composition of a facility's wastewater discharge because wet towers concentrate certain pollutants in the effluent waste stream. The cooling towers designed for CCPP operate at 1.5 cycles of concentration, i.e., the blowdown discharge will contain a dissolved solids concentration 50 percent higher than the makeup water.

Changes to discharge composition may affect compliance with water quality criteria included in the SIP. If compliance with these objectives becomes problematic, alternative treatment or discharge methods may be necessary. Compliance may be achieved by altering the discharge configuration in such a way as to increase dilution (e.g., diffuser ports), or by seeking a mixing zone and dilution credits as permissible under the SIP and Basin Plan. Alternately, some low volume waste streams (e.g., boiler blowdown, laboratory drains) may be diverted, with necessary permits, for treatment at a POTW.

If more pollutant-specific treatment methods, such as filtration or precipitation technologies, become necessary to meet WQBELs, the initial capital cost may range from $2 to $5.50 per 1,000 gallons of treatment capacity, with annual costs of approximately $0.5 per gallon of capacity, depending on the method of treatment (FRTR 2002). Hazardous material disposal fees and permits would further increase costs.

This evaluation did not include alternative discharge or effluent treatment measures in the conceptual design because the variables used to determine final WQBELs, which would be used to determine the type and scope of the desired compliance method, cannot be quantified here. Likewise, the final cost evaluation (Section 4.0) does not include any allowance for these possibilities.

Existing thermal discharges to an estuary are limited to a maximum discharge temperature of 20º F above the receiving water's natural temperature, may not exceed 86º F, and meet other criteria specified by the Thermal Plan (SWRCB 1972). CCPP applied for, and received, an exception to this Thermal Plan requirement. The current order permits the discharge of elevated-temperature wastes that do not exceed the natural receiving water temperature by more than 37º F at flood tide (CVRWQCB 2001). No information was available to assess compliance with this permit requirement. Because cooling tower blowdown will be taken from the "cold" side of the tower, conversion to a wet cooling system will significantly reduce the discharge temperature (to less than 78º F) and the size of any related thermal plume in the receiving water, thus enabling CCPP to meet the initial requirements of the Thermal Plan.

3.4.4 RECLAIMED WATER

Reclaimed or alternative water sources used in conjunction with wet cooling towers could eliminate all surface water withdrawals at CCPP. Doing so would completely eliminate impingement and entrainment concerns, and might enable the facility to avoid possible effluent quality and permit compliance issues, depending on the quality of reclaimed water available for use. In addition, wet cooling towers using reclaimed water would be expected to have lower PM_{10} emissions due to the lower TDS levels. The California State Water Resources Control Board (SWRCB), in 1975, issued a policy statement requiring the consideration of alternative cooling methods in new power plants, including reclaimed water, over the use of freshwater (SWRCB 1975). There is no similar policy regarding marine waters, but the clear preference of state agencies is to encourage alternative cooling methods, including reclaimed water, wherever possible.

The present volume of available reclaimed water within a 15-mile radius of CCPP (62 mgd) does not meet the current once-through cooling demand; thus, reclaimed water is only applicable as a source of makeup water for a wet cooling tower system. This study did not pursue a detailed investigation of the use of reclaimed water because the conversion of CCPP's once-through cooling system to saltwater cooling towers meets the performance benchmarks for impingement and entrainment impact reductions discussed in the 2006 California Ocean Protection Council (OPC) Resolution on Once-Through Cooling Water (see Chapter 1).

To be acceptable for use as makeup water in cooling towers, reclaimed water must meet tertiary treatment and disinfection standards under California Code of Regulations (CCR) Title 22. If the reclaimed water is not treated to the required levels, CCPP would be required to arrange for sufficient treatment, either onsite or at the source facility, prior to its use in the cooling towers.

An additional consideration for reclaimed water is the presence of any ammonia or ammonia-forming compounds in the reclaimed water. All the condenser tubes at CCPP contain copper alloys (aluminum brass) and can experience stress-corrosion cracking as a result of the interaction between copper and ammonia. Treatment for ammonia may include adding ferrous sulfate as a corrosion inhibitor or require ammonia-stripping towers to pretreat reclaimed water prior to use in the cooling towers (USEPA 2000).

Three publicly owned treatment works (POTWs) were identified within a 15-mile radius of CCPP, with a combined discharge capacity of 62 mgd. Figure B–6 shows the relative locations of these facilities to CCPP.

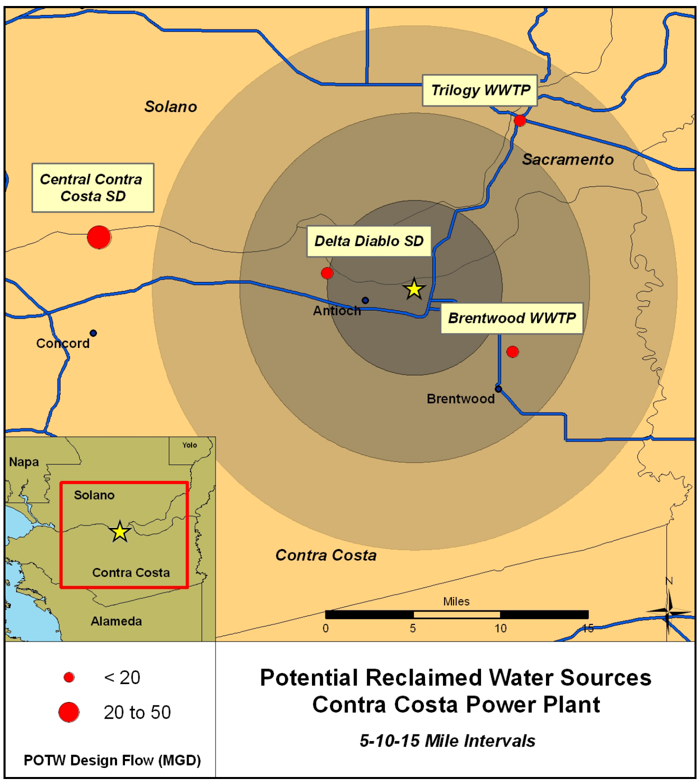

Figure B–6. Reclaimed Water Sources

- *Delta Diablo Sanitation District (DDSD)—Antioch*
  Discharge volume: 14 mgd
  Distance: 5 miles W
  Treatment level: 40% secondary; 60% tertiary

  DDSD has the capacity to treat approximately 8 mgd of effluent to tertiary treatment standards. Reclaimed water is currently used as makeup water for the Los Medanos Energy Center, Delta Energy Center, and small irrigation projects in the region. The balance of effluent that is treated to secondary standards (6 mgd) would be sufficient to provide two-thirds of the freshwater tower makeup demand at CCPP (9 to 12 mgd), although arrangements for tertiary treatment would have to be made prior to its use.

- *Trilogy Wastewater Treatment Plant—Rio Vista*
  Discharge volume: 0.5 mgd
  Distance: 11 miles W
  Treatment level: Secondary

  The small volume of water that might be available from this facility is impractical for use at CCPP.

- *Brentwood Wastewater Treatment Plant—Brentwood*
  Discharge volume: 5 mgd
  Distance: 8 miles SE
  Treatment level: Tertiary

  All effluent is treated to tertiary standards and discharged to Marsh Creek. No current claims or uses of treated effluent were identified. The available volume could provide 50 percent of the makeup water requirement for freshwater towers at CCPP.

The costs associated with installing transmission pipelines (excavation/drilling, material, labor), in addition to design and permitting costs, are difficult to quantify in the absence of a detailed analysis of various site-specific parameters that will influence the final configuration. No single facility has sufficient capacity to provide CCPP with the required volume of cooling water. Two facilities would have to be accessed to obtain sufficient water (DDSD and Brentwood).The nearest facility with sufficient capacity to satisfy CCPP's makeup demand (9 to 12 mgd for freshwater towers) is located 9.5 miles west of the facility (Central Contra Costa Sanitation District). Depending on seasonal flows, the available volume may not be sufficient and would require some means of a backup cooling system or source.

Based on data compiled for this study and others, the estimated installed cost of a 24-inch prestressed concrete cylinder pipe, sufficient to provide 12 mgd to CCPP, is $300 per linear foot, or approximately $1.6 million per mile. Additional considerations, such as pump capacity and any required treatment, would increase the total cost.

Regulatory concerns beyond the scope of this investigation, however, may make reclaimed water (as a makeup water source) comparable or preferable to brackish water from Suisun Bay. Reclaimed water may enable CCPP to eliminate potential conflicts with water discharge limitations or reduce PM_{10} emissions from the cooling tower, which is a concern, given the San Francisco Bay Area air basin's current nonattainment status.

At any facility where wet cooling towers are a feasible alternative, reclaimed water may be used as a makeup water source. The practicality of its use, however, depends on the overall cost, availability, and additional environmental benefit that may occur.

3.4.5 THERMAL EFFICIENCY

Wet cooling towers at CCPP will increase the condenser inlet water temperature by a range of 5 to 19° F above the surface water temperature, depending on the ambient wet bulb temperature at the time. The generating units at CCPP are designed to operate at the conditions described in Table B–12. The resulting monthly difference between once-through and wet cooling tower condenser inlet temperatures is described in Figure B–7.

Table B–12. Design Thermal Conditions

	Unit 6	Unit 7
Design backpressure (in. HgA)	1.5	1.5
Design water temperature (°F)	63	63
Turbine inlet temp (°F)	1,050	1,050
Turbine inlet pressure (psia)	2,400	2,400
Full load heat rate (BTU/kWh) [a]	9,592	9,428

[a] CEC 2006.

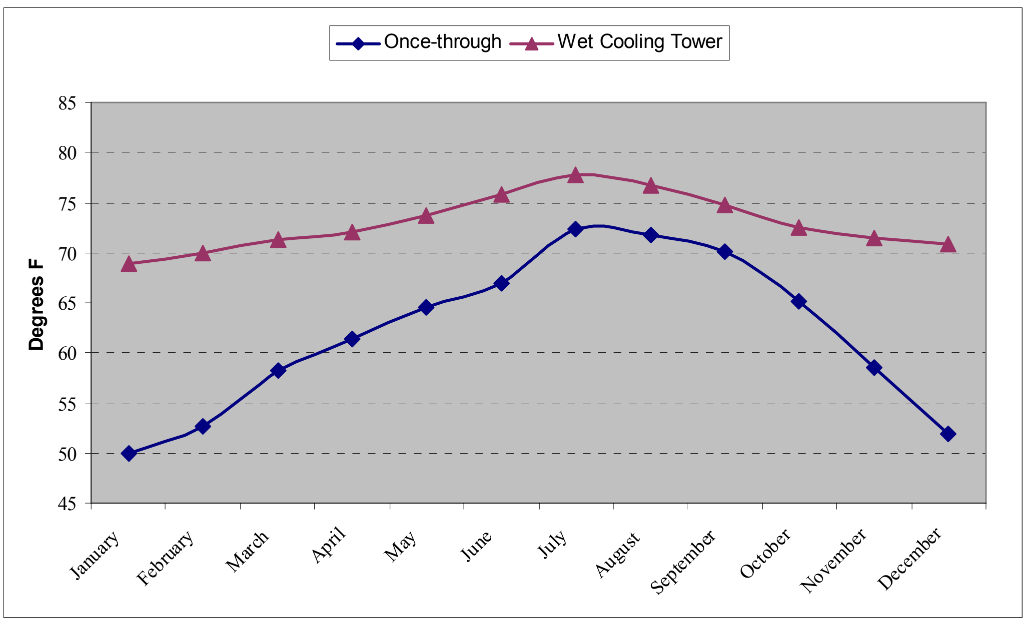

Figure B–7. Condenser Inlet Temperatures

Backpressures for the once-through and wet cooling tower configurations were calculated for each month using the design criteria described in the sections above and ambient climate data (Table B–6). In general, backpressures associated with the wet cooling tower were elevated by 0.35 to 0.85 inches HgA compared with the current once-through system (Figure B–8 and Figure B–10).

Heat rate adjustments were calculated by comparing the theoretical change in available energy that occurs at different turbine exhaust backpressures, assuming the thermal load and turbine inlet pressure remain constant, i.e., at the full load rating. The relative change at different backpressures was compared with the value calculated for the design conditions (i.e., at design turbine inlet and exhaust backpressures) and plotted as a percentage of the full load operating heat rate to develop estimated correction curves (Figure B–9 and Figure B–11).[5]

The difference between the estimated once-through and closed-cycle heat rates for each month represents the approximate heat rate increase that would be expected when converting to wet cooling towers.

Table B–13 summarizes the annual average heat rate increase for each unit as well as the increase associated with the peak demand period of July-August-September. Monthly values were used to calculate the monetized value of these heat rate changes (Section 4.6.2). Month-by-month calculations are presented in Appendix A.

Table B–13. Summary of Estimated Heat Rate Increases

	Unit 6	Unit 7
Peak (July-August-September)	0.56%	0.56%
Annual average	0.76%	0.76%

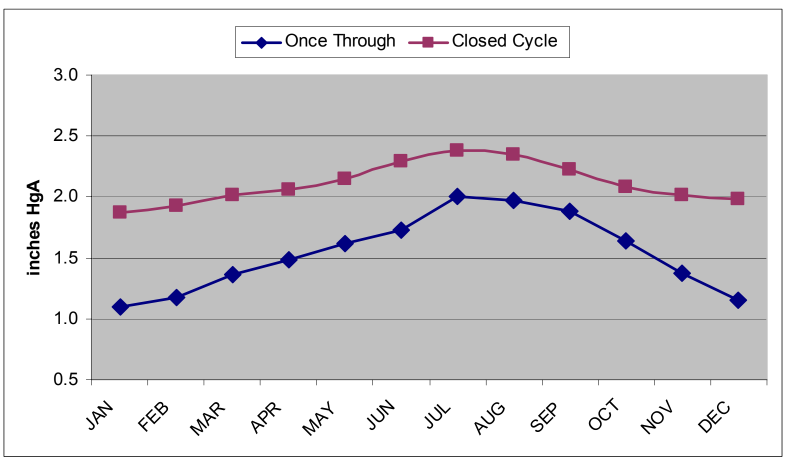

Figure B–8. Estimated Backpressures (Unit 6)

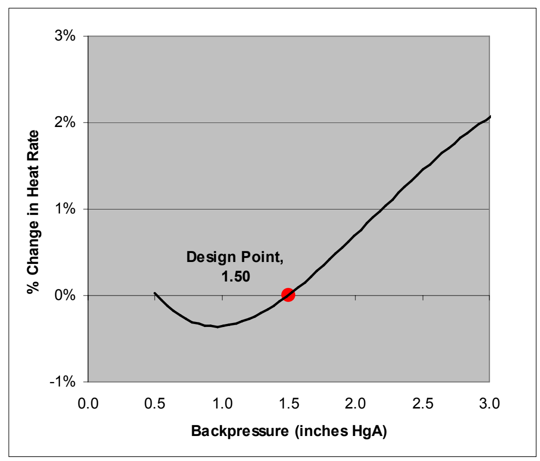

Figure B–9. Estimated Heat Rate Correction (Unit 6)

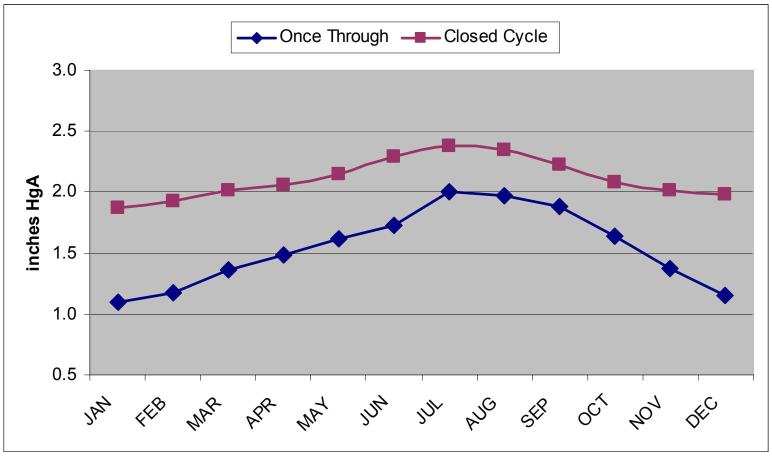

Figure B-10. Estimated Backpressures (Unit 7)

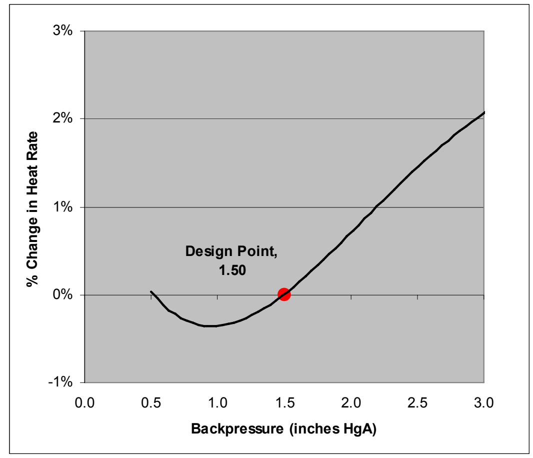

Figure B-11. Estimated Heat Rate Correction (Unit 7)

4.0 RETROFIT COST ANALYSIS

The wet cooling system retrofit estimate for CCPP is based on incorporating conventional wet cooling towers as a replacement for the existing once-through system for each unit. Standard cost elements for this project include the following:

- Direct (cooling tower installation, civil/structural, mechanical, piping, electrical, and demolition)
- Indirect (smaller project costs not itemized)
- Contingency (allowance for unknown project variables)
- Revenue loss from shutdown (net loss in revenue during construction phase)
- Operations and maintenance (non–energy related cooling tower operations)
- Energy penalty (includes increased parasitic use from fans and pumps as well as decreased thermal efficiency)

The cost analysis does not include allowances for elements that are not quantified in this study, such as land acquisition, effluent treatment, or air emission reduction credits. The methodology used to develop cost estimates is discussed in Chapter 5.

4.1 COOLING TOWER INSTALLATION

The wet cooling system retrofit estimate for CCPP is based on incorporating a conventional wet cooling tower as a replacement for the existing once-through system. Table B–14 summarizes the design-and-build cost estimate for each tower developed by vendors, inclusive of all labor and management required for their installation.

Table B–14. Wet Cooling Tower Design-and-Build Cost Estimate

	Unit 6	Unit 7	CCPP total
Number of cells	12	12	**24**
Cost/cell ($)	531,667	531,667	**531,667**
Total CCPP D&B cost ($)	**6,380,000**	**6,380,000**	**12,760,000**

4.2 OTHER DIRECT COSTS

A significant portion of wet cooling tower installation costs result from the various support structures, materials, equipment, and labor necessary to prepare the cooling tower site and connect the towers to the condenser. At CCPP, these costs comprise approximately 80 percent of the initial capital cost. Line item costs are detailed in Appendix B.

Deviations from or additions to the general cost elements discussed in Chapter 5 are discussed below. Other direct costs (non–cooling tower) are summarized in Table B–15.

- *Civil, Structural, and Piping*
  The cooling towers' location with respect to the generating units represents the largest single increase in cost over an average configuration. More than 9,000 feet of large-diameter pipe are required to service both cooling towers.
- *Mechanical and Electrical*
  Initial capital costs in this category reflect the new pumps (four total) to circulate cooling water between the towers and condensers. No new pumps are required to provide makeup water from Suisun Bay. Electrical costs are based on the battery limit after the main feeder breakers.
- *Demolition*
  No demolition costs are required.

Table B–15. Summary of Other Direct Costs

	Equipment ($)	Bulk material ($)	Labor ($)	CCPP total ($)
Civil/structural/piping	4,900,000	17,000,000	12,900,000	**34,800,000**
Mechanical	6,000,000	0	600,000	**6,600,000**
Electrical	1,300,000	2,700,000	2,300,000	**6,300,000**
Demolition	0	0	0	**0**
Total CCPP other direct costs	**12,200,000**	**19,700,000**	**15,800,000**	**47,700,000**

4.3 INDIRECT AND CONTINGENCY

Indirect costs are calculated as 25 percent of all direct costs (civil/structural, mechanical, electrical, demolition, and cooling towers).

An additional allowance is included for condenser water box and tube sheet reinforcement to withstand the increased pressures associated with a recirculating system. Each condenser may require reinforcement of the tube sheet bracing with 6-inch x 1-inch steel, and water box reinforcement/replacement with 5/8-inch carbon steel. Based on the estimates outlined in Chapter 5, a conservative estimate of 5 percent of all direct costs is included to account for possible condenser modifications.

The contingency cost is calculated as 25 percent of the sum of all direct and indirect costs, including condenser reinforcement. At CCPP, potential costs in this category include relocating or demolishing small buildings and structures and potential interferences from underground structures.

Soils were not characterized for this analysis. CCPP is situated near sea level adjacent to the San Joaquin River. The area in which cooling towers will be located is surrounded by marshes and wetlands that may require additional pilings to support any large structures built at the site. Initial capital costs are summarized in Table B–16.

Table B–16. Summary of Initial Capital Costs

	Cost ($)
Cooling towers	12,800,000
Civil/structural/piping	34,800,000
Mechanical	6,600,000
Electrical	6,300,000
Demolition	0
Indirect cost	15,100,000
Condenser modification	3,000,000
Contingency	19,600,000
Total CCPP capital cost	**98,200,000**

4.4 SHUTDOWN

A portion of the work relating to installing wet cooling towers can be completed without significant disruption to the operations of CCPP. Units will be offline depending on the length of time it takes to integrate the new cooling system and conduct acceptance testing. For CCPP, a conservative estimate of 4 weeks per unit was developed. Based on 2006 generating output, however, no shutdown is forecast for either unit. Therefore, the cost analysis for CCPP does not include any loss of revenue associated with shutdown at CCPP.

This analysis did not consider shutdown with respect to the required availability of a particular generating unit, nor can it automatically be assumed that the generating profile for 2006 will be the same in each subsequent year. Net output data from 2006 may not reflect any contractual obligations that mandate a particular unit's availability during a given time period.

4.5 OPERATIONS AND MAINTENANCE

Operations and maintenance (O&M) costs for a wet cooling tower system at CCPP include routine maintenance activities; chemicals and treatment systems to control fouling and corrosion in the towers; management and labor; and an allowance for spare parts and replacement. Annual costs are calculated based on the combined tower flow rate using a base cost of $4.00/gpm in Year 1 and $5.80/gpm in Year 12, with an annual escalator of 2 percent (USEPA 2001). Year 12 costs increase based on the assumption that maintenance needs, particularly for spare parts and replacements, will be greater for years 12–20. Annual O&M costs, based on the design circulating water flow for the two cooling towers at CCPP (321,000 gpm), are presented in Table B–17. These costs reflect maximum operation.

Table B–17. Annual O&M Costs (Full Load)

	Year 1 cost ($)	Year 12 cost ($)
Management/labor	300,000	435,000
Service/parts	480,000	696,000
Fouling	420,000	609,000
Total CCPP O&M cost	**1,200,000**	**1,740,000**

4.6 ENERGY PENALTY

The energy penalty is divided into two components: increased parasitic use from the added electrical demand from tower fans and pumps; and the decrease in thermal efficiency from elevated turbine backpressures. Monetizing the energy penalty at CCPP requires some assumption as to how the facility will choose to alter its operations to compensate for these changes, if at all. One option would be to accept the reduced amount of revenue-generating electricity available for sale and absorb the economic loss ("production loss option"). A second option would be to increase the firing rate to the turbine (i.e., consume more fuel) and produce the same amount of revenue-generating electricity as had been obtained with the once-through cooling system ("increased fuel option"). The degree to which a facility is able, or prefers, to operate at a higher firing rate, however, produces the more likely scenario—some combination of the two.

Ultimately, the manner in which CCPP would alter operations to address efficiency changes is driven by considerations unknown to this study (e.g., corporate strategy, contractual obligations, operating protocols, and turbine pressure tolerances). In all summary cost estimates, this study calculates the energy penalty's monetized value by assuming the facility will use the increased fuel option to compensate for reduced efficiency and generate the amount of electricity equivalent to the estimated shortfall. With this option, the energy penalty is equivalent to the financial cost of additional fuel and is nominally less costly than the production loss option. This option, however, may not reflect long-term costs, such as increased maintenance or system degradation, that may result from continued operation at a higher-than-designed turbine firing rate.[3]

The energy penalty for CCPP is calculated by first estimating the increased parasitic demand from the cooling tower pumps and fans, expressed as a percentage of each unit's rated capacity. Likewise, the change in the unit's heat rate is also expressed as a capacity percentage.

[3] Increasing the thermal load to the turbine will raise the circulating water temperature exiting the condenser. The cooling towers selected for this study are designed with a maximum water return temperature of approximately 120º F. Depending on each unit's operating conditions (i.e., condenser outlet temperature), the degree to which the thermal input to the turbine can be increased may be limited.

4.6.1 INCREASED PARASITIC USE (FANS AND PUMPS)

Depending on ambient conditions or the operating load at a given time, CCPP may be able to take one or more cooling tower cells offline and still obtain the required level of cooling. This would also reduce the cumulative electrical demand from the fans. For the purposes of this study, however, operations are evaluated at the design conditions, i.e., full load; no allowance is made for seasonal changes. The increased electrical demand from cooling tower fan operation is summarized in Table B–18.

Table B–18. Cooling Tower Fan Parasitic Use

	Tower 1	Tower 2	CCPP total
Units served	Unit 6	Unit 7	--
Generating capacity (MW)	340	340	**680**
Number of fans (one per cell)	12	12	**24**
Motor power per fan (hp)	211	211	--
Total motor power (hp)	2,526	2,526	**5,052**
MW total	1.88	1.88	**3.76**
Fan parasitic use (% of capacity)	**0.55%**	**0.55%**	**0.55%**

Additional circulating water pump capacity for the wet cooling towers will also increase the parasitic electricity usage at CCPP. Makeup water will continue to be withdrawn from the San Joaquin River with one of the existing circulating water pumps; the remaining pumps will be retired.

The net increase in pump-related parasitic usage is the difference between the new wet cooling tower configuration (new plus retained pumps) and the existing once-through configuration. For calculation purposes, this study assumes full load operation to estimate the cost of increased parasitic use. Final estimates, therefore, allocate the retained pump’s electrical demand to each tower based on the proportion of the facility’s generating capacity it services. Operating fewer towers or tower cells will alter the allocation of the retained pump’s electrical demand, but not the total demand.

Because one of the main design assumptions maintains the existing flow rate through each condenser, the new circulating pumps are single speed and are assumed to operate at their full rated capacity when in use. The increased electrical demand associated with cooling tower pump operation is summarized in Table B–19.

Table B–19. Cooling Tower Pump Parasitic Use

	Tower 1	Tower 2	CCPP Total
Units served	Unit 6	Unit 7	--
Generating capacity (MW)	340	340	**680**
Existing pump configuration (hp)	1,040	1,040	**2,080**
New pump configuration (hp)	4,669	4,669	**9,338**
Difference (hp)	3,629	3,629	**7,258**
Difference (MW)	2.7	2.7	**5.4**
Net pump parasitic use (% of capacity)	**0.80%**	**0.80%**	**0.80%**

4.6.2 HEAT RATE CHANGE

Heat rate adjustments were calculated based on each month's ambient climate conditions and reflect the estimated difference between operations with once-through and wet cooling tower systems. As noted above, the energy penalty analysis assumes CCPP will increase its fuel consumption to compensate for lost efficiency and the increased parasitic load from fans and pumps. The higher turbine firing rate will increase the thermal load rejected to the condenser, which, in turn, results in a higher backpressure value and corresponding increase in the heat rate. No data are available describing the changes in turbine backpressures above the design thermal loads. For the purposes of monetizing the energy penalty only, this study conservatively assumed an additional increase in the heat rate of 0.5 percent at the higher firing rate; the actual effect at CCPP may be greater or less. Changes in the heat rate for each unit at CCPP are presented in Figure B–12 and Figure B–13.

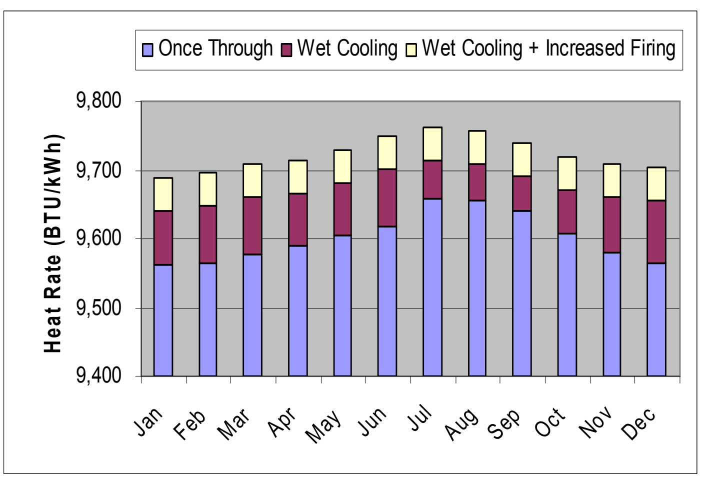

Figure B–8. Estimated Heat Rate Change (Unit 6)

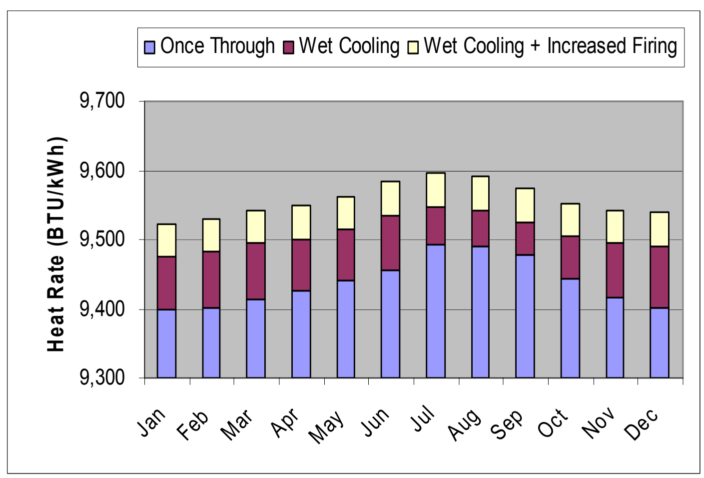

Figure B–9. Estimated Heat Rate Change (Unit 7)

4.6.3 CUMULATIVE ESTIMATE

Using the increased fuel option, the energy penalty's cumulative value is obtained by first calculating the relative costs of generation ($/MWh) for the once-through system and the wet cooling system adjusted for a higher turbine firing rate. The cost of generation for CCPP is based on the relative heat rates developed in Section 4.6.2 and the average monthly wholesale natural gas cost ($/MMBTU) (ICE 2006a). The difference between these two values represents the monthly increased cost, per MWh, that results from converting to wet cooling towers. This value is then applied to the net MWh generated for each month and summed to calculate the annual cost.

Based on 2006 output data, the Year 1 energy penalty for CCPP will be approximately $90,000. In contrast, the energy penalty's value calculated with the production loss option would be approximately $210,000. Together, these values represent the range of potential energy penalty costs for CCPP. Table B–20 and Table B–21 summarize the energy penalty estimates for each unit using the increased fuel option.

Table B-20. Unit 6 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	9,563	57.38	9,688	58.13	0.75	0	**0**
February	5.50	9,566	52.61	9,696	53.33	0.72	0	**0**
March	4.75	9,578	45.50	9,708	46.11	0.62	0	**0**
April	4.75	9,590	45.55	9,715	46.15	0.59	0	**0**
May	4.75	9,605	45.62	9,729	46.21	0.59	0	**0**
June	5.00	9,619	48.09	9,750	48.75	0.65	3,940	**2,575**
July	6.50	9,658	62.78	9,763	63.46	0.68	21,958	**14,868**
August	6.50	9,655	62.75	9,758	63.42	0.67	630	**422**
September	4.75	9,641	45.80	9,740	46.26	0.47	0	**0**
October	5.00	9,608	48.04	9,718	48.59	0.55	0	**0**
November	6.00	9,579	57.47	9,709	58.25	0.78	0	**0**
December	6.50	9,565	62.17	9,704	63.08	0.91	0	**0**
							Unit 6 total	**17,865**

Table B–21. Unit 7 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	9,399	56.40	9,522	57.13	0.74	0	**0**
February	5.50	9,402	51.71	9,531	52.42	0.71	0	**0**
March	4.75	9,414	44.72	9,542	45.33	0.61	0	**0**
April	4.75	9,426	44.77	9,549	45.36	0.58	0	**0**
May	4.75	9,441	44.84	9,563	45.42	0.58	7,322	**4,256**
June	5.00	9,455	47.27	9,583	47.92	0.64	15,364	**9,876**
July	6.50	9,493	61.71	9,596	62.37	0.67	52,729	**35,111**
August	6.50	9,489	61.68	9,591	62.34	0.66	20,061	**13,223**
September	4.75	9,477	45.01	9,573	45.47	0.46	19,707	**9,044**
October	5.00	9,444	47.22	9,552	47.76	0.54	0	**0**
November	6.00	9,415	56.49	9,543	57.26	0.77	0	**0**
December	6.50	9,401	61.11	9,538	62.00	0.89	0	**0**
							Unit 7 total	**71,510**

4.7 NET PRESENT COST

The net present value (NPC) of a wet cooling system retrofit at CCPP is the sum of all annual expenditures over the project's 20-year life span discounted according to the year in which the expense is incurred and the selected discount rate. The NPC represents the total change in revenue streams, in 2007 dollars, that CCPP can expect over 20 years as a direct result of converting to wet cooling towers. The following values were used to calculate the NPC at a 7 percent discount rate:

- *Capital and Start-up.* Includes all capital, indirect, contingency, and shutdown costs. All costs in this category are incurred in Year 0. (See Table B–16.)
- *Annual O&M.* Base cost values for Year 1 and Year 12 are adjusted for subsequent years using a 2 percent year-over-year escalator. Because CCPP has a relatively low capacity utilization factor, O&M costs for the NPC calculation were estimated at 30 percent of their maximum value. (See Table B–17.)
- *Annual Energy Penalty.* Sufficient information is not available to this study to forecast future generating output at CCPP. In lieu of annual estimates, this study uses the net MWh output from 2006 as the calculation basis for years 1–20. Wholesale prices include a year-over-year price escalator of 5.8 percent (based on the Producer Price Index). The energy penalty values are based on the increased fuel option discussed in Section 4.6. (See Table B–20 and Table B–21.)

Using these values, the NPC_{20} for CCPP is $104 million. Appendix C contains detailed annual calculations used to develop this cost.

4.8 ANNUAL COST

The annual cost incurred by CCPP for a wet cooling tower retrofit is the sum of annual amortized capital costs plus the annual average of O&M and energy penalty expenditures. Capital costs are amortized at a 7 percent discount rate over 20 years. O&M and energy penalty costs are calculated in the same manner as for the NPC_{20} (Section 4.7). Revenue losses from a construction-related shutdown, if any, are incurred in Year 0 only and not included in the annual cost summarized in Table B–22.

Table B–22. Annual Cost

Discount rate (%)	Capital cost ($)	Annual O&M ($)	Annual energy penalty ($)	Annual cost ($)
7.00%	9,300,000	500,000	200,000	**10,000,000**

4.9 COST-TO-GROSS REVENUE COMPARISON

Financial data available to conduct a detailed analysis of the economic impact that a wet cooling system retrofit will have on CCPP's annual revenues are limited. The facility's gross annual revenue can be approximated using 2006 net generating data (CEC 2006) and average wholesale prices for electricity as recorded at the SP 15 trading hub (ICE 2006b). This estimate, therefore, does not reflect any changes that may result from different wholesale prices or contract agreements that may increase or decrease the gross revenue summarized below, nor does it account for annual fixed revenue requirements or other variable costs.

The estimate of gross annual revenue from electricity sales at CCPP is a straightforward calculation that multiplies the monthly wholesale cost of electricity by the amount generated for the particular month. The estimated gross revenue for CCPP is summarized in Table B–23. A comparison of annual costs to annual gross revenue is summarized in Table B–24.

Table B–23. Estimated Gross Revenue

	Wholesale price ($/MWh)	Net generation (MWh)		Estimated gross revenue ($)		
		Unit 6	Unit 7	Unit 6	Unit 7	CCPP total
January	66	0	0	0	0	**0**
February	61	0	0	0	0	**0**
March	51	0	0	0	0	**0**
April	51	0	0	0	0	**0**
May	51	0	7,322	0	373,422	**373,422**
June	55	3,940	15,364	216,700	845,020	**1,061,720**
July	91	21,958	52,729	1,998,178	4,798,339	**6,796,517**
August	73	630	20,061	45,990	1,464,453	**1,510,443**
September	53	0	19,707	0	1,044,471	**1,044,471**
October	57	0	0	0	0	**0**
November	66	0	0	0	0	**0**
December	67	0	0	0	0	**0**
	CCPP total	**26,528**	**115,183**	**2,260,868**	**8,525,705**	**10,786,573**

Table B–24. Cost-to-Gross Revenue Comparison

Estimated gross annual revenue ($)	Initial capital		O&M		Energy penalty		Total annual cost	
	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross
10,800,000	9,300,000	86	500,000	4.6	200,000	1.9	**10,000,000**	**93**

5.0 OTHER TECHNOLOGIES

Within the scope of this study, and using the OPC resolution's stated goal of reducing impingement and entrainment by 90–95 percent as a benchmark, the effectiveness of other technologies commonly used to address such impacts could not be conclusively determined for use at CCPP.

Among these technologies, however, and within the framework of this study, fine-mesh wedgewire screens exhibit the greatest potential for successful deployment. A final conclusion as to their applicability will have to be based on a more detailed site-specific investigation of the source water's physical characteristics. A more detailed analysis that also comprises a biological evaluation may determine the applicability of one or more of these technologies to CCPP. A brief summary of the applicability of these technologies follows.

5.1 MODIFIED RISTROPH SCREENS—FINE MESH

The principal concern with this technology is the successful return of viable organisms captured on the screens to the source water body. CCPP currently withdraws its cooling water through a shoreline CWIS on the southern bank of the San Joaquin River. Modifying the existing traveling screens to include fine-mesh panels and a return system would require expanding the existing CWIS and identifying a suitable return location to prevent re-impingement. These modifications, and the potential for success, are plausible but require detailed investigation of the potentially affected species in the San Joaquin River before a conclusive determination can be made.

5.2 BARRIER NETS

If impingement is a significant concern at CCPP, a barrier net could conceivably be placed in the San Joaquin River as an impingement control measure in addition to flow reduction methods. Successful deployment of a barrier net would depend on how far offshore the net would extend and whether this would interfere with the river's navigational or recreational uses. Debris loadings in the delta as well as the impact from any storms or tidal movements would also need to be addressed before deployment.

Costs for barrier nets are not significant and depend on the net's size and the amount of maintenance required. Seasonal deployments may be possible, and thereby reduce costs, if migratory patterns in the San Joaquin River allow. Based on estimates developed for the Phase II rule, barrier net initial capital costs for CCPP range from $160,000 to $200,000, with annual O&M costs of approximately $30,000 to $40,000 (USEPA 2004). Maintenance costs include replacement of net panels, which can be high depending on the frequency of replacement.

5.3 AQUATIC FILTRATION BARRIERS

An evaluation of an aquatic filtration barrier (AFB) at CCPP was proposed as part of a Habitat Conservation Program contained in the existing order. Difficulties pertaining to the AFB's installation and maintenance at one of Mirant's New York facilities precluded a complete evaluation at CCPP. Maintenance concerns were driven by fouling and the inability to maintain a sufficiently clean fabric (Mirant Delta 2006). AFBs have not been demonstrated to be effective in an estuarine environment at the scale necessary for CCPP. Any such installation would have to address the potential for high sediment loads and fouling that would adversely affect performance.

5.4 VARIABLE SPEED DRIVES

Variable speed drives (VSDs) are currently installed at CCPP, but no information was available to evaluate their use and any relative reductions in impingement or entrainment.

5.5 CYLINDRICAL FINE-MESH WEDGEWIRE

Cylindrical wedgewire screens have been deployed in estuarine settings with physical characteristics similar to those that would be experienced in the Sacramento/San Joaquin Delta. Fine-mesh applications may be susceptible to fouling or clogging due to sediment loads, but may be feasible at CCPP.

To function as intended, cylindrical wedgewire screens must be submerged in a water body with a consistent ambient current of 0.5 feet per second (fps). Ideally, this current is unidirectional so that screens may be oriented properly and any debris impinged on the screens will be carried downstream when the airburst cleaning system is activated.

Data obtained from U.S. Geological Survey (USGS) stream flow gages for the San Joaquin River in the vicinity of CCPP show average ambient currents exceed 0.5 fps for more than 92 percent of the time (Figure B–14) (USGS 2007). Prior to screen installation, more accurate current measurements in the precise screen location would have to be taken.

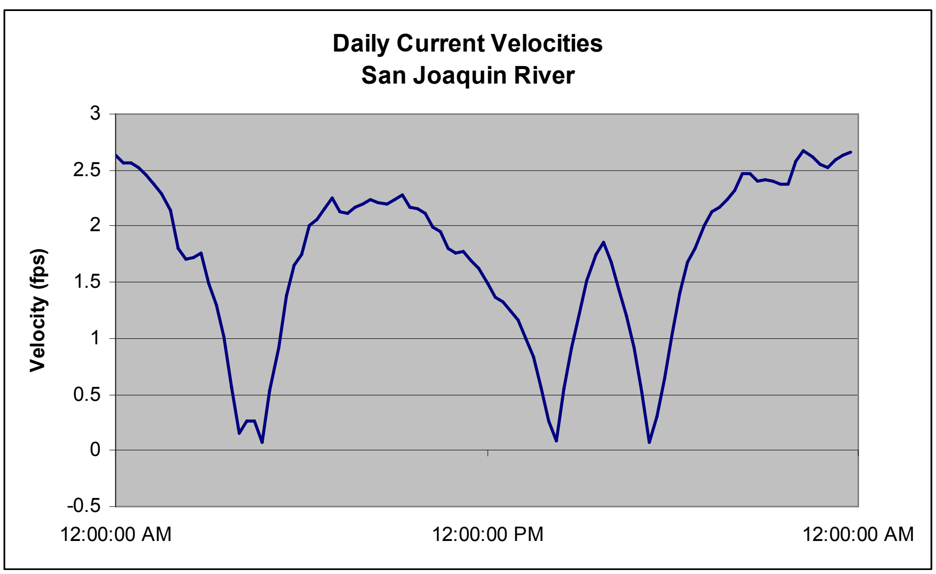

Figure B–10. Diurnal San Joaquin River Currents (Jersey Point)

Based on the limited data available, a conceptual plan and cost for fine-mesh wedgewire screens was developed for an installation at CCPP. Fine-mesh wedgewire screens for CCPP would be installed offshore in Suisun Bay approximately 950 feet north of the Unit 6 and Unit 7 CWIS. This location is deep enough for five 84-inch-diameter screen assemblies; shoreline or bulkhead wall placement would require dredging in front of the intake, dismantling the dock, and continued maintenance to prevent sediment buildup. The screens' general placement at CCPP is shown in Figure B–11. Approximate costs are summarized in Table B–25.

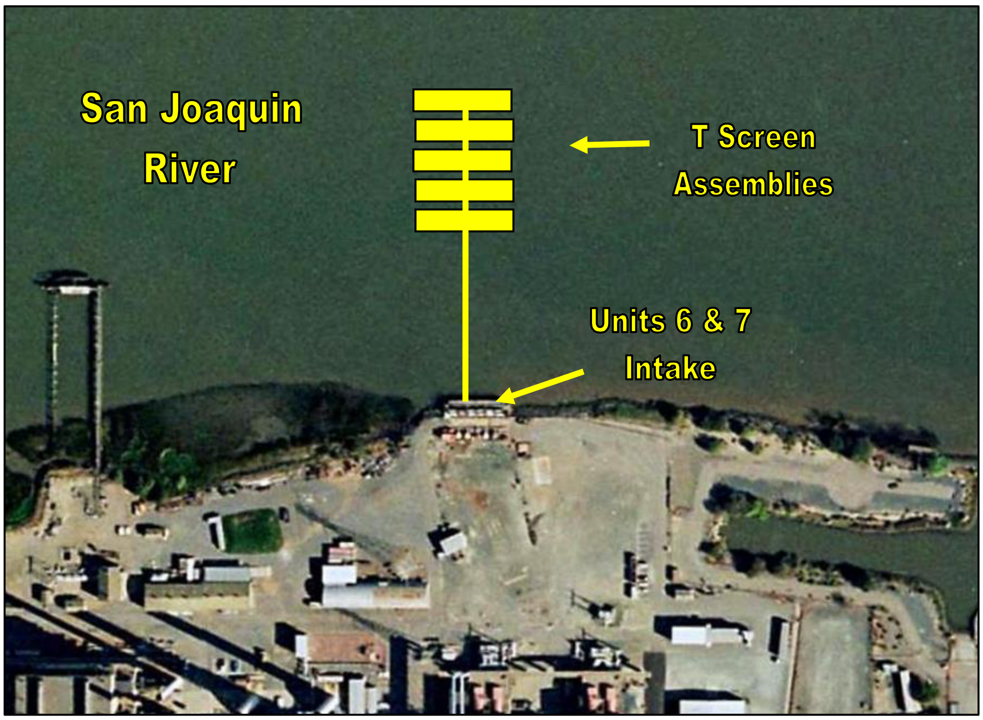

Figure B–11. Approximate Cylindrical Wedgewire Screen Location

Table B–25. Estimated Cost of Fine-Mesh Wedgewire Screens

	Installed cost ($)
5 T-screens (84" x 300") [a]	1,940,000
Piping (120") [b]	4,600,000
Indirect / contingency	925,000
CCPP total	**7,465,000**

[a] T-screen cost includes airburst cleaning system (GLV 2007).
[b] PCCP piping costs based on vendor price quotes and installation estimates for 120" pipe used in this study. Underwater installation costs may vary.

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Appendix A. Once-Through and Closed-Cycle Thermal Performance

		Unit 1			Unit 2		
		Once through	Closed cycle	Net increase	Once through	Closed cycle	Net increase
JAN	Backpressure (in. HgA)	1.09	1.87	**0.78**	1.09	1.87	**0.78**
	Heat rate Δ (%)	*-0.30*	*0.50*	***0.80***	*-0.30*	*0.50*	***0.80***
FEB	Backpressure (in. HgA)	1.17	1.93	**0.76**	1.17	1.93	**0.76**
	Heat rate Δ (%)	*-0.28*	*0.59*	***0.86***	*-0.28*	*0.59*	***0.86***
MAR	Backpressure (in. HgA)	1.36	2.01	**0.65**	1.36	2.01	**0.65**
	Heat rate Δ (%)	*-0.15*	*0.71*	***0.85***	*-0.15*	*0.71*	***0.85***
APR	Backpressure (in. HgA)	1.49	2.05	**0.57**	1.49	2.05	**0.57**
	Heat rate Δ (%)	*-0.02*	*0.78*	***0.80***	*-0.02*	*0.78*	***0.80***
MAY	Backpressure (in. HgA)	1.61	2.15	**0.54**	1.61	2.15	**0.54**
	Heat rate Δ (%)	*0.13*	*0.93*	***0.79***	*0.13*	*0.93*	***0.79***
JUN	Backpressure (in. HgA)	1.72	2.29	**0.57**	1.72	2.29	**0.57**
	Heat rate Δ (%)	*0.28*	*1.14*	***0.86***	*0.28*	*1.14*	***0.86***
JUL	Backpressure (in. HgA)	2.00	2.38	**0.38**	2.00	2.38	**0.38**
	Heat rate Δ (%)	*0.69*	*1.27*	***0.58***	*0.69*	*1.27*	***0.58***
AUG	Backpressure (in. HgA)	1.97	2.34	**0.37**	1.97	2.34	**0.37**
	Heat rate Δ (%)	*0.65*	*1.22*	***0.57***	*0.65*	*1.22*	***0.57***
SEP	Backpressure (in. HgA)	1.89	2.22	**0.34**	1.89	2.22	**0.34**
	Heat rate Δ (%)	*0.52*	*1.03*	***0.52***	*0.52*	*1.04*	***0.52***
OCT	Backpressure (in. HgA)	1.64	2.08	**0.44**	1.64	2.08	**0.44**
	Heat rate Δ (%)	*0.17*	*0.81*	***0.64***	*0.17*	*0.81*	***0.64***
NOV	Backpressure (in. HgA)	1.37	2.02	**0.64**	1.37	2.02	**0.64**
	Heat rate Δ (%)	*-0.14*	*0.72*	***0.85***	*-0.14*	*0.72*	***0.85***
DEC	Backpressure (in. HgA)	1.15	1.98	**0.84**	1.15	1.98	**0.84**
	Heat rate Δ (%)	*-0.29*	*0.67*	***0.95***	*-0.29*	*0.67*	***0.95***

Note: Heat rate delta represents change from design value calculated according to estimated ambient conditions for each month.

Appendix B. Itemized Capital Costs

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
CIVIL / STRUCTURAL / PIPING	--	--	--	--	--	--	--	--	--	--
Allocation for extra works related to installation of pipes under the road (building a temporary deviation road, traffic control & signalization, removing these temporary installations and putting the site back like it was before.	lot	1	--	--	250,000	250,000	2,500.00	100	250,000	**500,000**
Allocation for other accessories (bends, water hammers…)	lot	1	--	--	500,000	500,000	4,000.00	95	380,000	**880,000**
Allocation for pipe racks (approx 600 ft) and cable racks	t	60	--	--	2,500	150,000	17.00	105	107,100	**257,100**
Allocation for sheet piling and dewatering	lot	1	--	--	500,000	500,000	5,000.00	100	500,000	**1,000,000**
Allocation for testing pipes	lot	1	--	--	--	--	2,000.00	95	190,000	**190,000**
Allocation for Tie-Ins to existing condenser's piping	lot	1	--	--	250,000	250,000	2,000.00	95	190,000	**440,000**
Allocation for trust blocks	lot	1	--	--	50,000	50,000	500.00	95	47,500	**97,500**
Backfill for PCCP pipe (reusing excavated material)	m3	33,868	--	--	--	--	0.04	200	270,944	**270,944**
Bedding for PCCP pipe	m3	5,236	--	--	40	209,440	0.04	200	41,888	**251,328**
Bend for PCCP pipe 24" diam (allocation)	ea	12	--	--	3,000	36,000	20.00	95	22,800	**58,800**
Bend for PCCP pipe 72" diam (allocation)	ea	12	--	--	18,000	216,000	40.00	95	45,600	**261,600**
Bend for PCCP pipe 84" diam (allocation)	ea	18	--	--	20,000	360,000	50.00	95	85,500	**445,500**
Building architectural (siding, roofing, doors, painting…etc)	ea	2	--	--	250,000	500,000	3,000.00	82	492,000	**992,000**
Butterfly valves 30" c/w allocation for actuator & air lines	ea	32	30,800	985,600	--	--	50.00	95	152,000	**1,137,600**
Butterfly valves 72" c/w allocation for actuator & air lines	ea	12	96,600	1,159,200	--	--	75.00	95	85,500	**1,244,700**
Butterfly valves 84" c/w allocation for actuator & air lines	ea	16	124,600	1,993,600	--	--	75.00	95	114,000	**2,107,600**
Check valves 30"	ea	4	44,000	176,000	--	--	16.00	95	6,080	**182,080**
Check valves 72"	ea	4	138,000	552,000	--	--	32.00	95	12,160	**564,160**
Concrete basin walls (all in)	m3	372	--	--	250	93,000	8.00	82	244,032	**337,032**
Concrete elevated slabs (all in)	m3	646	--	--	275	177,650	10.00	82	529,720	**707,370**
Concrete for transformers and oil catch basin (allocation)	m3	200	--	--	275	55,000	10.00	82	164,000	**219,000**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Concrete slabs on grade (all in)	m3	2,931	--	--	220	644,820	4.00	82	961,368	**1,606,188**
Ductile iron cement pipe 12" diam. for fire water line	ft	3,500	--	--	100	350,000	0.60	95	199,500	**549,500**
Excavation and backfill for fire line, blowdown & make-up (using excavated material for backfill except for bedding)	m3	13,594	--	--	--	--	0.08	200	217,504	**217,504**
Excavation for PCCP pipe	m3	53,501	--	--	--	--	0.04	200	428,008	**428,008**
Fencing around transformers	m	50	--	--	33	1,650	1.00	82	4,100	**5,750**
Flange for PCCP joints 24"	ea	8	--	--	1,725	13,800	14.00	95	10,640	**24,440**
Flange for PCCP joints 30"	ea	24	--	--	2,260	54,240	16.00	95	36,480	**90,720**
Flange for PCCP joints 72"	ea	8	--	--	9,860	78,880	25.00	95	19,000	**97,880**
Flange for PCCP joints 84"	ea	16	--	--	13,210	211,360	30.00	95	45,600	**256,960**
Foundations for pipe racks and cable racks	m3	140	--	--	275	38,500	8.00	82	91,840	**130,340**
FRP flange 30"	ea	96	--	--	1,679	161,198	50.00	95	456,000	**617,198**
FRP flange 72"	ea	24	--	--	20,888	501,304	200.00	95	456,000	**957,304**
FRP flange 84"	ea	20	--	--	33,381	667,621	300.00	95	570,000	**1,237,621**
FRP pipe 72" diam.	ft	200	--	--	851	170,280	1.20	95	22,800	**193,080**
FRP pipe 84" diam.	ft	1,400	--	--	946	1,324,400	1.50	95	199,500	**1,523,900**
Harness clamp 24" c/w external testable joint	ea	20	--	--	1,715	34,300	14.00	95	26,600	**60,900**
Harness clamp 30" & 36"c/w internal testable joint	ea	125	--	--	2,000	250,000	16.00	95	190,000	**440,000**
Harness clamp 72" c/w internal testable joint	ea	80	--	--	2,440	195,200	18.00	95	136,800	**332,000**
Harness clamp 84" c/w internal testable joint	ea	450	--	--	2,845	1,280,250	20.00	95	855,000	**2,135,250**
Joint for FRP pipe 72" diam.	ea	12	--	--	3,122	37,462	200.00	95	228,000	**265,462**
Joint for FRP pipe 84" diam.	ea	40	--	--	5,014	200,552	300.00	95	1,140,000	**1,340,552**
PCCP pipe 24" dia. For blowdown	ft	400	--	--	98	39,200	0.50	95	19,000	**58,200**
PCCP pipe 30" dia. for make-up	ft	2,500	--	--	125	312,500	0.70	95	166,250	**478,750**
PCCP pipe 72" diam.	ft	1,600	--	--	507	811,200	1.30	95	197,600	**1,008,800**
PCCP pipe 84" diam.	ft	9,000	--	--	562	5,058,000	1.50	95	1,282,500	**6,340,500**
Riser (FRP pipe 30" diam X55 ft)	ea	24	--	--	15,350	368,395	150.00	95	342,000	**710,395**
Structural steel for building	t	315	--	--	2,500	787,500	20.00	105	661,500	**1,449,000**
CIVIL / STRUCTURAL / PIPING TOTAL	**--**	**--**	**--**	**4,866,400**	**--**	**16,939,702**	**--**	**--**	**12,894,414**	**34,700,516**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
ELECTRICAL	--	--	--	--	--	--	--	--	--	--
4.16 kv cabling feeding MCC's	m	1,500	--	--	75	112,500	0.40	110	66,000	**178,500**
4.16kV switchgear - 4 breakers	ea	1	250,000	250,000	--	--	150.00	110	16,500	**266,500**
480 volt cabling feeding MCC's	m	750	--	--	70	52,500	0.40	110	33,000	**85,500**
480V Switchgear - 1 breaker 3000A	ea	4	30,000	120,000	--	--	80.00	110	35,200	**155,200**
Allocation for automation and control	lot	1	--	--	750,000	750,000	7,500.00	110	825,000	**1,575,000**
Allocation for cable trays and duct banks	m	2,500	--	--	75	187,500	1.00	110	275,000	**462,500**
Allocation for lighting and lightning protection	lot	1	--	--	100,000	100,000	1,000.00	110	110,000	**210,000**
Dry Transformer 2MVA xxkV-480V	ea	4	100,000	400,000	--	--	100.00	110	44,000	**444,000**
Lighting & electrical services for pump house building	ea	2	--	--	45,000	90,000	500.00	110	110,000	**200,000**
Local feeder for 250 HP motor 460 V (up to MCC)	ea	24	--	--	18,000	432,000	150.00	110	396,000	**828,000**
Local feeder for 2500 HP motor 4160 V (up to MCC)	ea	4	--	--	42,000	168,000	170.00	110	74,800	**242,800**
Oil Transformer 10/13.33MVA xx-4.16kV	ea	2	190,000	380,000	--	--	150.00	110	33,000	**413,000**
Primary breaker(xxkV)	ea	4	45,000	180,000	--	--	60.00	110	26,400	**206,400**
Primary feed cabling (assumed 13.8 kv)	m	4,500	--	--	175	787,500	0.50	110	247,500	**1,035,000**
ELECTRICAL TOTAL	**--**	**--**	**--**	**1,330,000**	**--**	**2,680,000**	**--**	**--**	**2,292,400**	**6,302,400**
MECHANICAL	--	--	--	--	--	--	--	--	--	--
Allocation for ventilation of buildings	ea	2	100,000	200,000	--	--	1,000.00	95	190,000	**390,000**
Cooling tower for unit 6	lot	1	6,380,000	6,380,000	--	--	--	--	--	**6,380,000**
Cooling tower for unit 7	lot	1	6,380,000	6,380,000	--	--	--	--	--	**6,380,000**
Overhead crane 50 ton in (in pump house) Including additional structure to reduce the span	ea	2	500,000	1,000,000	--	--	1,000.00	95	190,000	**1,190,000**
Pump 4160 V 2500 HP	lot	4	1,200,000	4,800,000	--	--	580.00	95	220,400	**5,020,400**
MECHANICAL TOTAL	**--**	**--**	**--**	**18,760,000**	**--**	**0**	**--**	**--**	**600,400**	**19,360,400**

Appendix C. Net Present Cost Calculation

Project year	Capital/start-up ($)	O & M ($)	Energy penalty ($)		Total ($)	Annual discount factor	Present value ($)
			Unit 1	Unit 2			
0	98,100,000	--	--	--	98,100,000	1	**98,100,000**
1	--	360,000	17,866	71,509	449,375	0.9346	**419,986**
2	--	367,200	18,907	75,678	461,785	0.8734	**403,323**
3	--	374,544	20,010	80,090	474,644	0.8163	**387,452**
4	--	382,035	21,176	84,759	487,970	0.7629	**372,272**
5	--	389,676	22,411	89,701	501,787	0.713	**357,774**
6	--	397,469	23,717	94,930	516,117	0.6663	**343,888**
7	--	405,418	25,100	100,465	530,983	0.6227	**330,643**
8	--	413,527	26,563	106,322	546,412	0.582	**318,012**
9	--	421,797	28,112	112,520	562,430	0.5439	**305,905**
10	--	430,233	29,751	119,080	579,064	0.5083	**294,338**
11	--	438,838	31,485	126,023	596,346	0.4751	**283,324**
12	--	532,440	33,321	133,370	699,131	0.444	**310,414**
13	--	543,089	35,263	141,145	719,498	0.415	**298,591**
14	--	553,951	37,319	149,374	740,644	0.3878	**287,222**
15	--	565,030	39,495	158,083	762,607	0.3624	**276,369**
16	--	576,330	41,798	167,299	785,427	0.3387	**266,024**
17	--	587,857	44,234	177,052	809,143	0.3166	**256,175**
18	--	599,614	46,813	187,374	833,802	0.2959	**246,722**
19	--	611,606	49,542	198,298	859,447	0.2765	**237,637**
20	--	623,838	52,431	209,859	886,128	0.2584	**228,976**
Total							**104,325,047**

C. DIABLO CANYON POWER PLANT

PACIFIC GAS & ELECTRIC—AVILA BEACH, CA

Contents

Tables

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Appendices

1.0 GENERAL SUMMARY

Retrofitting the existing once-through cooling system at Diablo Canyon Power Plant (DCPP) with closed-cycle wet cooling towers is technically and logistically feasible based on this study's design criteria, and will reduce cooling water withdrawals from the Pacific Ocean by approximately 96 percent. Impingement and entrainment impacts would be reduced by a similar proportion.

The preferred option selected for DCPP includes 2 conventional wet cooling towers (without plume abatement), with individual cells arranged in a back-to-back configuration to accommodate limited space at the site. Sufficient area does not exist at the site to accommodate plume-abated towers.

The location of the DCPP site along a narrow coastal terrace at the foot of the Irish Hills combined with the layout of existing structures at the facility complicates the identification of suitable areas in which to place cooling towers. Any retrofit project that incorporates a closed-cycle system requires the relocation of various support structures—employee parking areas, warehouses, and maintenance facilities—to other areas that do not appear to be available within the portion of the property that is zoned for industrial development. Off-site relocation of parking areas and support services, if feasible, would increase project costs and are beyond the scope of this study.

Construction-related shutdowns are estimated to take approximately 8 months for both units (concurrent). As a baseload facility, DCPP would incur a substantial financial loss as a result. The configuration of DCPP does not enable a staggered retrofit (one unit at a time). As a nuclear facility, DCPP is subject to the Nuclear Regulatory Commission's (NRC) oversight and approval for substantial changes to the existing system operations as described in this chapter. It is unclear how the NRC's review and approval process might affect any downtime estimates.

The cooling tower configuration designed under the preferred option complies with all identified local use restrictions and includes necessary mitigation measures, where applicable.

1.1 COST

Initial capital and net present costs associated with the installation and operation of wet cooling towers at DCPP are summarized in Table C–1. Annualized costs based on 20-year average values for the various cost elements are summarized in Table C–2. A detailed cost analysis is presented in Section 4.0 of this chapter.

Table C–1. Cumulative Cost Summary

Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Total capital and start-up [a]	1,621,000,000	84	88
NPC_{20} [b]	3,021,000,000	157	164

[a] Includes all costs associated with the construction and installation of cooling towers and shutdown loss.
[b] NPC_{20} includes all capital costs, operation and maintenance costs, and energy penalty costs over 20 years, discounted at 7.0 percent.

Table C–2. Annual Cost Summary

Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Initial capital [a]	84,500,000	4.38	4.58
Operations and maintenance	9,100,000	0.47	0.49
Energy penalty	140,200,000	7.27	7.59
Total DCPP annual cost	**233,800,000**	**12.12**	**12.66**

[a] Does not include revenue loss associated with shutdown, which is incurred in Year 0 only. The loss of revenue from shutdown is estimated to be $727 million.

1.2 ENVIRONMENTAL

Environmental changes associated with the conversion of the existing once-through cooling system at DCPP to a wet cooling tower system are summarized in Table C–3 and discussed further in Section 3.4 of this chapter.

Table C–3. Environmental Summary

		Unit 1	Unit 2
Water use	Design intake volume (gpm)	862,690	862,690
	Cooling tower makeup water (gpm)	37,400	37,400
	Reduction from capacity (%)	96	96
Energy efficiency	Summer heat rate increase (%)	3.60	3.60
	Summer energy penalty (%)	5.00	5.00
	Annual heat rate increase (%)	3.61	3.61
	Annual energy penalty (%)	5.01	5.01
Direct air emissions [a]	PM10 emissions (tons/yr) (maximum capacity)	496	496
	PM10 emissions (tons/yr) (2006 capacity utilization)	512	438

[a] Does not include stack emissions from sources used to supplement the projected generation shortfall, if obtained from fossil fuel facilities.

1.3 OTHER POTENTIAL FACTORS

Considerations outside this study's scope may limit the practicality or overall feasibility of a wet cooling tower retrofit at Diablo Canyon.

The time required to complete a cooling system retrofit at DCPP is estimated to be approximately 8 months, during which time neither Unit 1 nor Unit 2 would be available to generate electricity to the grid. Cooling system interconnections (both units share a common intake structure) and the disruption to the facility as a whole precludes converting one unit at a time while the other remains operational. The net impact is the temporary removal of 2,200 MWe from the grid.

DCPP's location in a relatively unspoiled section of the central coast likely adds to permitting and approval concerns because major excavation of the existing site and bluffs and hillsides in the coastal zone will require Coastal Commission approval.

2.0 BACKGROUND

DCPP is a nuclear-powered steam electric generating facility approximately 8 miles north-northwest of Avila Beach in San Luis Obispo County, owned and operated by Pacific Gas and Electric (PG&E). The facility occupies approximately 750 acres (585 industrially zoned) on a mostly undeveloped section of the Central Coast at the foot of the Irish Hills, a subrange to the Santa Lucia Mountains. PG&E manages an additional 11,000 acres surrounding the facility that are primarily reserved for agricultural and grazing activities that preserve the undeveloped character of this section of the coastline. Public access to the vicinity is restricted (Figure C–1).

Figure C–1. Diablo Canyon Power Plant and Vicinity

The industrial-zoned portion of the site is an irregularly-shaped parcel at the foot of Diablo Canyon along a terraced coastal shelf beginning at approximately 90 feet above sea level (Figure C–2). Rocky cliffs predominate along the shore. Moving inland from the coast, the terrain gains elevation quickly—approximately 400 feet in 1/3 mile. Other facility structures (e.g., switchyard and raw water holding ponds) are located further up the canyon at elevations of approximately 350 feet. In general, this study focuses on areas below the 200-foot elevation because cooling tower construction above this elevation would require substantial excavation into the hillsides and, because the area is located within the coastal zone, would require obtaining the necessary coastal development permits.

Figure C–2. Site Overview

DCPP consists of two pressurized water reactor (PWR) steam electric units (Units 1 and 2), each rated at 1,100 MW, for a facility total of 2,200 MW (see Table C–4.). Other facility operations in the area surrounding Units 1 and 2 include employee parking lots, administration buildings, warehouses, machine shops and other essential support services (Table C–4 and Figure C–3).

Table C–4. General Information

Unit	In-service year	Rated capacity (MW)	2006 capacity utilization [a]	Condenser cooling water flow (gpm)
Unit 1	1985	1,100	102.9%	862,690
Unit 2	1986	1,100	88.5%	862,690
DCPP total		**2,200**	**95.7%**	**1,725,380**

[a] *Quarterly Fuel and Energy Report*–2006 (CEC 2006).

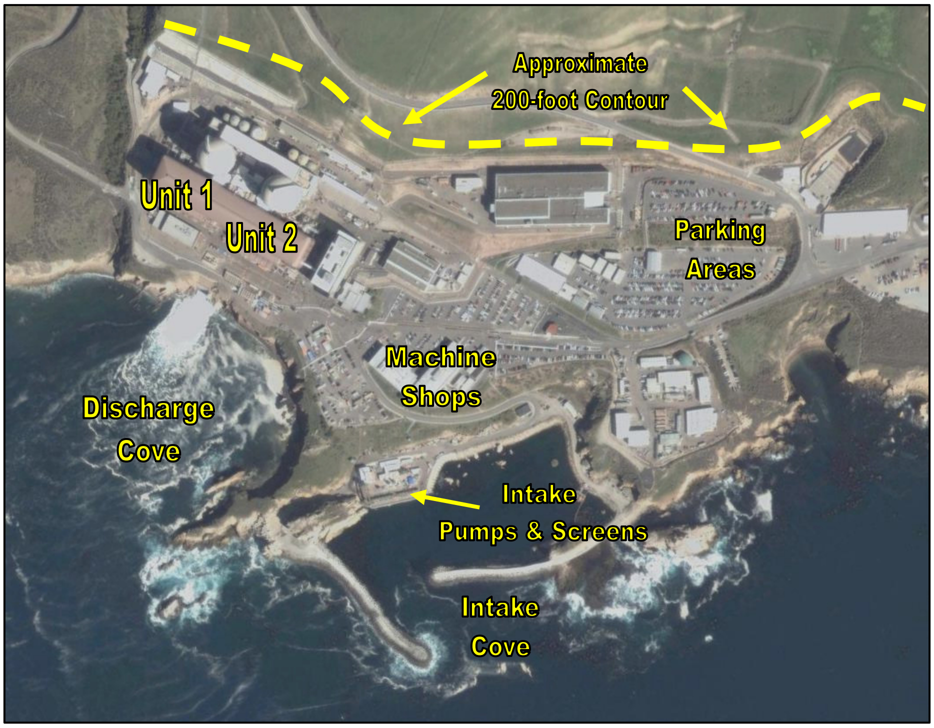

Figure C–3. Lower Site Overview

Figure C–4. Plant View (Eastward)

2.1 COOLING WATER SYSTEM

DCPP operates one cooling water intake structures (CWIS) to provide condenser cooling water to Units 1 and Unit 2. Once-through cooling water is combined with low-volume wastes generated by DCPP and discharged through a shoreline outfall to the Pacific Ocean. Surface water withdrawals and discharges for each unit are regulated by individual National Pollutant Discharge Elimination System (NPDES) Permit CA0003751 as implemented by Central Coast Regional Water Quality Control Board (CCRWQCB) 90-09.

Cooling water is withdrawn through a shoreline intake structure in a cove partially protected with man-made breakwaters. The CWIS comprises inclined bar racks and traveling screens along with auxiliary and main cooling water pumps. A concrete curtain wall extends 7.75 feet below mean sea level to keep out floating debris. Water divides to four separate screen bays, two per unit. Each screen bay is fitted with three vertical traveling screen assemblies with 3/8-inch stainless steel mesh panels. Screens rotate at 10 or 20 feet/minute, depending on the debris loadings, with rotation cycles determined manually or by the pressure differential between the upstream and downstream faces of the screen. A high-pressure spray removes any debris or fish that have become impinged on the screen face into sluiceways that empty into a refuse sump and finally to the intake cove.

Downstream of the six intake screens are four circulating water pumps, each rated at 433,500 gallons per minute (gpm), or 624 million gallons per day (mgd). Each unit has a design pump capacity totaling 867,000 gpm, or 1,248 mgd, for a facility total of 1,734,000 gpm, or 2,497 mgd.

2.2 SECTION 316(B) PERMIT COMPLIANCE

The CWIS currently in operation at DCPP does not use technologies generally considered to be effective at reducing impingement mortality and/or entrainment.

The CCRWQCB, in proposed Order RB3-2003-0009,[1] found that impingement was a relatively insignificant concern at DCPP. With only a few hundred fish impinged per year, "this impact is so minor that no alternative technologies are necessary to addressed impingement at DCPP, and the cost of any impingement reduction technology would be wholly disproportionate to the benefit to be gained" (CCRWQCB 2003, Attachment 4). While the Second Circuit ruling in the Phase II decision rejected a direct comparison of costs and benefits in determining best technology available (BTA) for Section 316(b) compliance, the severity of impingement impacts, or lack thereof, would appear to support the CCRWQCB's finding of no significant impact from impingement.

Entrainment impacts, however, have been found to be significant for certain species and constitute an adverse impact (CCRWQCB 2003). Under the direction of the CCRWQCB, PG&E conducted a comprehensive Section 316(b) demonstration study to evaluate the effects of cooling water withdrawals at DCPP and the options that may be available to address any impacts. A technical working group was formed consisting of PG&E and CCRWQCB staff members, as well as US EPA, the California Department of Fish and Game, the League for Coastal Protection and independent scientists. The final report was submitted in March 2000 (Tenera 2000).

[1] Order R3-2003-0009 was not formally adopted by the CCRWQCB.

In 2002, the CCRWQCB retained Tetra Tech to perform an evaluation of the feasibility and general cost of different technologies that could minimize entrainment impacts at DCPP. Tetra Tech's study reviewed closed-cycle technologies, both dry and wet, as well as fine-mesh screening systems and aquatic filtration barriers (AFBs). Dry cooling towers, freshwater cooling towers, fine-mesh screens and AFBs were all determined to be infeasible for application at DCPP because of the limited space, the effects on plant performance and extremes in ocean currents and weather that frequent the area during winter storms. Mechanical draft saltwater cooling towers were considered potentially feasible provided certain assumptions made regarding the relocation of facility structures were viable. The 2002 Tetra Tech report estimated the NPC of a wet cooling tower retrofit at DCPP, including annual operations and maintenance (O&M) costs and energy penalty costs, at $1,300 million.[2]

Based on the 2002 Tetra Tech report, benefits evaluations performed by other contractors, information provided by PG&E, and its own analysis, the CCRWQCB noted in the proposed order that the cost of saltwater wet cooling towers was wholly disproportionate to the monetized environmental benefit that could be gained (CCRWQCB 2003, Attachment 4). The Second Circuit's Phase II ruling rejected the direct comparison of costs to benefits when evaluating acceptable technology-based solutions to meet CWA 316(b). It is not clear how this ruling will affect similar determinations in future permit proceedings.

[2] Burns Engineering Services, Inc. (BES), on behalf of PG&E, addressed several areas that either were not evaluated in the 2002 Tetra Tech report or evaluated using different criteria and assumptions, including the availability of certain locations and additional costs related to condenser modifications and the energy penalty. This study addresses some of the differences between the two reports.

3.0 WET COOLING SYSTEM RETROFIT

3.1 OVERVIEW

This study evaluates the use of saltwater wet cooling towers at DCPP, with the current source water (Pacific Ocean) continuing to provide makeup water to the facility. Conversion of the existing once-through cooling system to wet cooling towers will reduce the facility's current intake capacity by approximately 96 percent; rates of impingement and entrainment will decline by a similar proportion. Use of reclaimed water was considered for DCPP but not analyzed in detail because the available volume of water is insufficient to replace the current once-through cooling volume withdrawn from the Pacific Ocean.

As a makeup water source, reclaimed water may be an attractive alternative when considering additional benefits its use may provide, such as avoidance of conflicts with effluent limitations or air emission standards. Securing a sufficient volume of makeup water from secondary or reclaimed sources in the vicinity (45 to 50 mgd in a freshwater configuration) is unlikely, however. Any wet cooling tower constructed at DCPP would have to use sea water for makeup water unless freshwater were produced onsite. Use of reclaimed water is discussed further in Section 3.4.4, below.

The configuration of the wet cooling towers—their size and location—was based on best professional judgment (BPJ) using the criteria outlined in Chapter 5 and designed to meet the performance benchmarks in the most cost-effective manner.

Previous analyses of wet cooling towers at DCPP have been conducted and include the following:

- A*ssessment of Alternatives to the Existing Cooling Water System (DCPP)*. Tera Corporation (Tera) for PG&E. 1982.
- *Diablo Canyon 316(b) Demonstration Report.* Tenera Environmental Services (Tenera) for PG&E. 2000.
- *Evaluation of Cooling System Alternatives: Diablo Canyon Power Plant*. Tetra Tech for CCRWQCB. 2002.
- *Feasibility of Retrofitting Cooling Towers at Diablo Canyon Power Plant Units 1 & 2*. Burns Engineering Services (BES) for PG&E. 2003.

Based on a review of information provided by these reports and obtained from public records, installing wet cooling towers at DCPP as a retrofit of the existing once-through cooling system faces significant logistical obstacles regarding the placement of the towers themselves as well as the relocation of existing structures to obtain sufficient space. The compact and irregular shape of the DCPP site combined with the complexities of a nuclear power plant would necessarily require significant disruption to the facility's operations for 8 months or more.

This study developed a conceptual design of wet cooling towers assuming conflicts over the availability of certain locations could be resolved. As designed, the towers are sufficient to meet the cooling demand for DCPP's two units without exceeding the turbine's design tolerances. Cost estimates are based on vendor quotes developed using the available information and the various design constraints identified at DCPP.

Converting to a wet cooling towers system will reduce the facility's available output by an annual average of 5.01 percent (approximately 110 MW). This is likely to be a major consideration if such a project moves forward. The overall practicality of retrofitting the Units 1 and 2 will require an evaluation of factors outside the scope of this study, such as the projected life span of the generating units and their role in the overall reliability of electricity production and transmission in California, particularly the Central Coast and Los Angeles regions.

3.2 DESIGN BASIS

3.2.1 CONDENSER SPECIFICATIONS

For this study, the conceptual design of the cooling towers selected for DCPP is based on the assumption that the condenser flow rate and thermal load will remain unchanged from the current system. Although no provision is included to re-optimize the condenser performance for service with a cooling tower, some modifications to the condenser (tube sheet and water box reinforcement) may be necessary to handle the increased water pressures that will result from the increased total pump head required to raise water to the elevation of the cooling tower riser.[3] Additional costs associated with condenser modifications are included in the discussion of capital expenditures (Section 4.3).

If wet cooling towers were installed, DCPP, as a facility with a projected remaining life span of 15 years or more (currently licensed to operate through 2024 and 2025 for Units 1 and 2), would likely pursue an overall strategy that included re-optimizing the condenser to minimize performance losses resulting from a conversion. Re-optimization would require extensive demolition and excavation of the existing site to gain access to the existing condensers (on the lower level of the turbine building) and reconfigure the tubes and supply and return lines connecting to the water boxes.

Because of the complexity and level of detail required to develop an accurate estimate of a condenser re-optimization for DCPP, no attempt is made to characterize the cost or impact on facility downtime during construction in this study. The 2003 BES report notes this type of modification may increase the construction-related downtime for the facility, although it is unclear how much of the condenser modification process would overlap with other cooling tower activities (BES 2003).

Data describing the DCPP's thermal performance and existing cooling system were obtained from the studies noted in Section 3.1 and publicly-available sources.

Table C–5 summarizes the condenser design specifications for Units 1 and 2 used in this study.

[3] In this context, re-optimization refers to a comprehensive overhaul of the condenser, such as re-tubing or converting the flow from single to multiple passes. Modifications are generally limited to reinforcement measures to enable the condenser to withstand the increased pressures.

Table C–5. Condenser Design Specifications

	Unit 1	Unit 2
Thermal load (MMBTU/hr)	7,764	7,764
Surface area (ft^2)	617,536	617,536
Condenser flow rate (gpm)	862,690	862,690
Tube material	Titanium	Titanium
Heat transfer coefficient (BTU/hr•ft^2•°F)	495	495
Cleanliness factor	0.9	0.9
Inlet temperature (°F)	60	60
Temperature rise (°F)	18.01	18.01
Steam condensate temperature (°F)	91.7	91.7
Turbine exhaust pressure (in. HgA)	1.5	1.5

3.2.2 AMBIENT ENVIRONMENTAL CONDITIONS

DCPP is in San Luis Obispo County, approximately 8 miles north-northwest of Avila Beach. Cooling water is withdrawn at the surface from the Pacific Ocean. The design water temperature of 60° F was obtained from the 1982 Tera report. Monthly water temperatures used in the development energy penalty estimates were obtained from the National Oceanographic and Atmospheric Administration (NOAA) *Coastal Water Temperature Guide—Avila Beach, CA* (NOAA 2007).

The wet bulb temperature used in the development of the overall cooling tower design was obtained from the 2003 BES report in which it is noted that the highest wet bulb temperature at DCPP is approximately 61° F.

The 2002 Tetra Tech report selected a design approach temperature of 9° F, which would yield "cold" water from the cooling towers at temperature of 70° F. The 2003 BES report disagreed with the feasibility of a 9° F approach temperature given the ambient wet bulb temperature of 61° F and suggested an approach temperature of 20° F that also accounted for the effects of recirculation and interference. The 1982 Tera report selected an approach temperature of 14° F but used a design wet bulb temperature of 65° F.

Based on consultations with cooling tower vendors, an approach temperature of 20° F was thought to be overly conservative in light of the data describing the DCPP site and climate patterns in the vicinity. This study selected a 17° F approach temperature to the 61° F wet bulb temperature, which will yield cold water from the cooling towers at 78° F during the peak climate periods.

Monthly maximum wet bulb temperatures used in the development of energy penalty estimates in Section 4.6 were obtained from National Climatic Data Center (NCDC) climate normals for Avila Beach and Pismo Beach, California (NCDC 2006). Climate data used in this analysis are summarized in Table C–6.

Table C-6. Surface Water and Ambient Wet Bulb Temperatures

	Surface (°F)	Ambient wet bulb (°F)
January	55.0	54.8
February	56.0	56.1
March	55.0	55.3
April	54.0	54.9
May	55.0	58.2
June	56.5	59.3
July	58.5	60.0
August	60.0	61.0
September	60.0	60.4
October	59.0	59.2
November	57.0	58.2
December	55.0	56.9

3.2.3 LOCAL USE RESTRICTIONS

3.2.3.1 NOISE

The DCPP site is covered by the County of San Luis Obispo General Plan and Local Coastal Plan. Section 3.3.5 of the Noise Element applies to stationary sources and limits ambient noise levels to no more than 70 dBA when measured at the property line of the potentially affected area, including agricultural and vacant lands. Noise from wet cooling towers at DCPP will not conflict with local noise ordinances because of the undeveloped nature of the surrounding area and the significant distance to the nearest adjoining property. Accordingly, no noise abatement measures, such as low noise fans or sound barrier walls, are included for DCPP.

3.2.3.2 BUILDING HEIGHT

DCPP is zoned for industrial use according to the county general plan. Height restrictions are based on the character of the surrounding area and the general use of the existing site. The height of the wet cooling towers designed for DCPP, from grade level to the top of the fan deck, is 59 feet.

3.2.3.3 PLUME ABATEMENT

Local zoning ordinances do not contain any specific criteria for addressing impacts associated with a wet cooling tower plume, nor is DCPP near any public infrastructure (e.g., bridges, freeways) that would be impacted by a visible plume. The proximity of DCPP to coastal recreational areas, and the potential visual impact on these resources, may require plume abatement measures. California Energy Commission (CEC) siting guidelines and Coastal Act provisions evaluate the total size and persistence of a visual plume with respect to aesthetic standards for coastal resources; significant visual changes resulting from a persistent plume would likely be subject to additional controls.

The 2003 BES report noted that fogging caused by wet cooling towers could create a significant safety hazard at DCPP but does not provide a basis for this assertion. The 1982 Tera report noted that wet mechanical draft cooling towers at DCPP would increase fog incidence at the facility by 38 hours per year. An evaluation of 4 years of climate data for the area showed that the natural fog incidence averaged 318 hours per year. Wet cooling towers would be expected to increase natural fog incidence by 12 percent to 356 hours per year total. This translates to an annual fog incidence of 4 percent (Tera 1982).

Plume-abated towers are not included in the design for DCPP. If they are required for other reasons, plume-abated towers could not be sited at the existing facility because they would require an available area that is substantially greater than what is currently available at the site.

3.2.3.4 DRIFT AND PARTICULATE EMISSIONS

Drift elimination measures that are considered best available control technology (BACT) are required for all cooling towers evaluated in this study, regardless of their location. State-of-the-art drift eliminators are included for each cooling tower cell at DCPP, with an accepted efficiency of 0.0005 percent. Because cooling tower PM_{10} emissions are a function of the rate of drift, drift eliminators are also considered BACT for PM_{10} emissions from wet cooling towers.

This efficiency can be verified by a proper in situ test, which accounts for site-specific climate, water, and operating conditions. Testing based on the Isokinetic Drift Test Code, published by the Cooling Tower Institute, is only required at initial start-up on one representative cell of each tower for an approximate cost of $120,000 (CTI 1994). This cost is not itemized in the final analysis and is instead included as part of the indirect cost estimate (Section 4.3).

3.2.3.5 FACILITY CONFIGURATION AND AREA CONSTRAINTS

The limited space available at DCPP, combined with the topography and existing uses of the site, creates significant challenges for identifying sufficient area to accommodate the large cooling towers that will be necessary to serve Units 1 and 2. Much of the main area below the 200-foot contour is currently occupied by the power blocks, various support structures, parking areas, and maintenance buildings. Placement of wet cooling towers at DCPP will require removal and/or relocation of some of these structures (Figure C–5).

Area 1 is occupied by the administration building, security offices, and cold machine shop. The cumulative size of this area (approximately 200,000 square feet) could accommodate the cooling tower for either Unit 1 or Unit 2, but not both. Use of this area would require relocating the administration building and would interfere with necessary access roads to and from the reactor buildings.

Area 2 is occupied by parking lots and temporary buildings. The irregular shape and total size (approximately 220,000 square feet) of this area does not allow for placement of the large back-to-back cooling towers that are required for DCPP without interfering with the main access road.

Area 3 is occupied by employee parking lots and the main warehouse, which is approximately 100,000 square feet. To install wet cooling towers in this area, suitable relocation spots for the main warehouse and parking areas must be identified. None are identified within the current boundaries of the PG&E property's industrially-zoned section.

Despite Area 3's limitations it was selected as the most feasible location in which to site wet cooling towers at DCPP, with the strong caveat that its use is contingent upon finding suitable replacement areas to house the support structures that currently occupy the space.

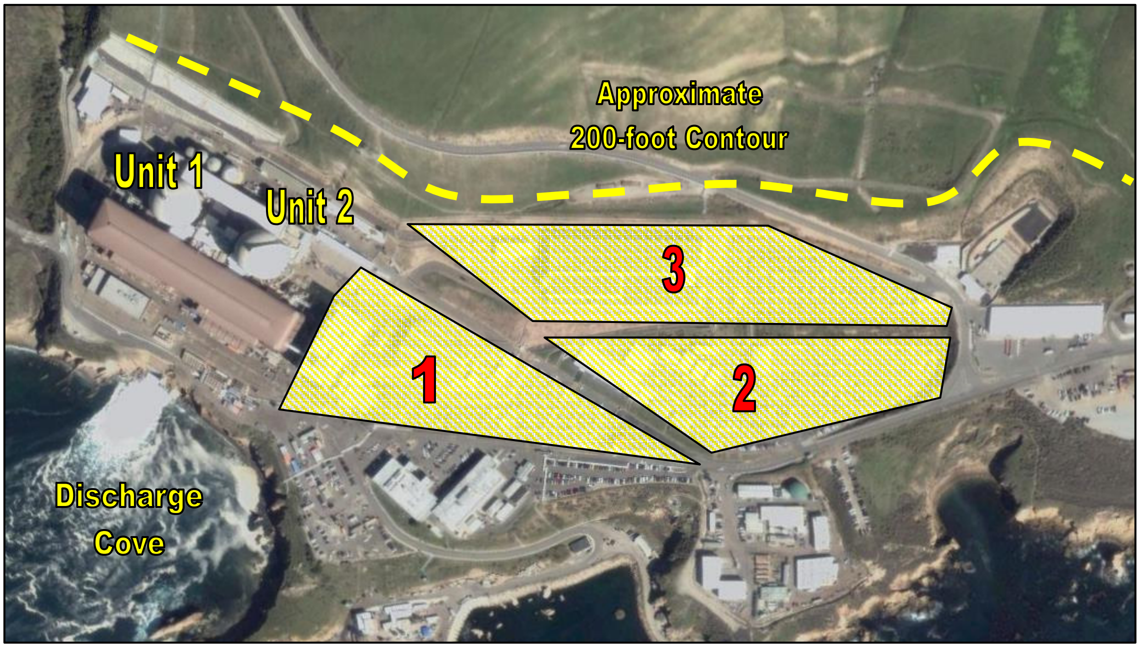

Figure C–5. Potential Tower Siting Areas

3.3 CONCEPTUAL DESIGN

Based on the design constraints discussed above, two wet cooling towers were selected to replace the current once-through cooling system at DCPP. Each tower will operate independently and be dedicated to one unit. Each tower at DCPP consists of conventional cells arranged in a multicell, back-to-back configuration.

3.3.1 SIZE

Each tower is constructed over a concrete collection basin 4 feet deep. The basin is larger than the footprint of the tower structure, extending an additional 2 feet in each direction. The concrete used for construction is suitable for saltwater applications. The principal tower material is fiberglass reinforced plastic (FRP) with stainless steel fittings. These materials are more resistant to the higher corrosive effects of saltwater.

The size of the tower is primarily based on the thermal load rejected to the tower by the surface condenser and a 17° F approach to the ambient wet bulb temperature. Flow rates through the condenser remain unchanged.

General characteristics of the wet cooling tower selected for DCPP are summarized in Table C–7.

Table C–7. Wet Cooling Tower Design

	Tower 1 (Unit 1)	Tower 2 (Unit 2)
Thermal load (MMBTU/hr)	7,764	7,764
Circulating flow (gpm)	862,690	862,690
Number of cells	52	52
Plume-abated/Conventional	Conventional	Conventional
Tower type	Mechanical draft	Mechanical draft
Flow orientation	Counterflow	Counterflow
Fill type	Modular splash	Modular splash
Arrangement	Back-to-back	Back-to-back
Primary tower material	FRP	FRP
Tower dimensions (l x w x h) (ft)	1404 x 108 x 59	1404 x 108 x 59
Tower footprint with basin (l x w) (ft)	1408 x 112	1408 x 112

3.3.2 LOCATION

The initial site selection for each tower was based on the desire to locate each tower as close as possible to its respective generating unit to minimize the supply and return pipe distances and any increases in total pump head and brake horsepower. The most feasible option available at DCPP places the towers approximately 1,100 feet from the generating units (Figure C–6). The selected location for the new pump is the same proposed by the 1982 Tera Corp study. This location could interfere with existing substructures in that area.

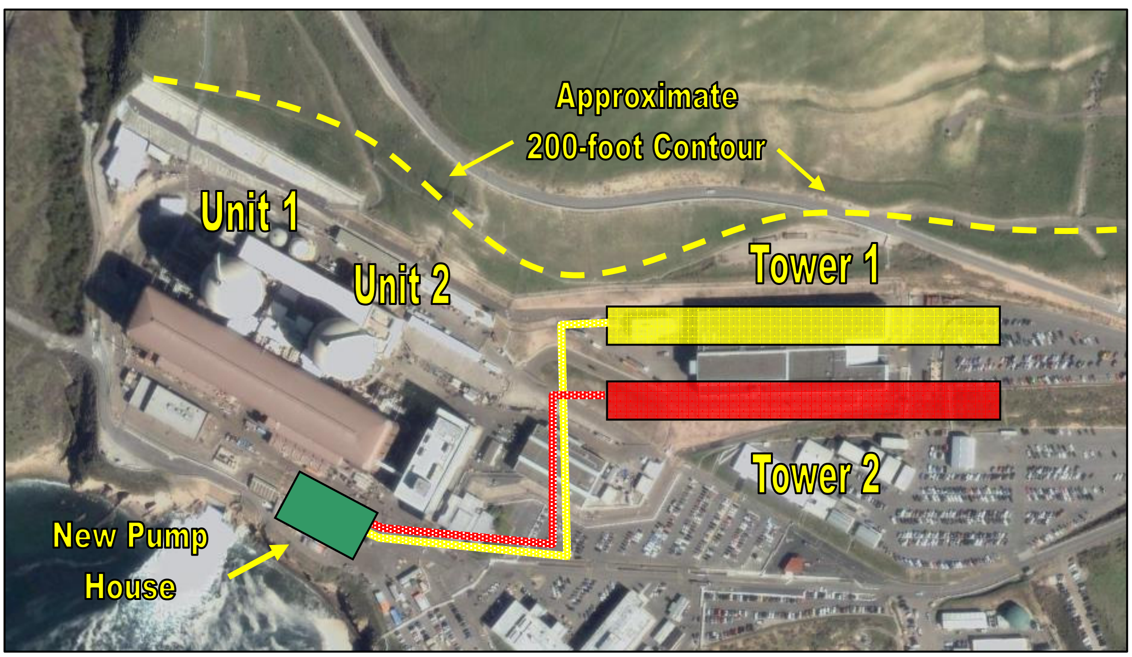

Figure C–6. Cooling Tower Locations

3.3.3 PIPING

All supply and return pipes are made of prestressed concrete cylinder pipe (PCCP) suitable for saltwater applications. Main pipes are 144” in diameter.

All riser piping (extending from the foot of the tower to the level of water distribution) is constructed of FRP.

Potential interference with underground obstacles and infrastructure is a concern, particularly at existing sites that are several decades old and have been substantially modified or rebuilt in the interim. Avoidance of these obstacles is considered to the degree practical in this study. Associated costs are included in the contingency estimate and are generally higher than similar estimates for new facilities (Section 4.3).

Appendix B details the total quantity of each pipe size and type for DCPP.

3.3.4 FANS AND PUMPS

Each tower cell uses an independent single-speed fan. The fan size and motor power are the same for each cell in both towers.

This analysis includes new pumps to circulate water between the condensers and cooling tower. Pumps are sized according to the flow rate for the tower, the relative distance between the tower and condenser, and the total head required to deliver water to the top of the cooling tower riser. A single multilevel pump house is constructed to serve both cooling towers and is sized to accommodate the motor control centers (MCCs) and appropriate electrical switchgear. The electrical installation includes all necessary transformers, cabling, cable trays, lighting, and lightning protection. A 50-ton overhead crane is also included to allow for pump servicing.

Water flows by gravity from the cooling tower basins to the pump house.

Fan and pump characteristics associated with a wet cooling tower at DCPP are summarized in Table C–8. The net electrical demand of the fans and new pumps are discussed further as part of the energy penalty analysis in Section 4.6.

Table C–8. Cooling Tower Fans and Pumps

		Tower 1 (Unit 1)	**Tower 2 (Unit 2)**
Fans	Number	52	52
	Type	Single speed	Single speed
	Efficiency	0.95	0.95
	Motor power (hp)	211	211
Pumps	Number	4	4
	Type	50% recirculating Mixed flow Suspended bowl Vertical	50% recirculating Mixed flow Suspended bowl Vertical
	Efficiency	0.88	0.88
	Motor power (hp)	6,932	6,932

3.4 ENVIRONMENTAL EFFECTS

Converting the existing once-through cooling system at DCPP to wet cooling towers will significantly reduce the intake of seawater from the Pacific Ocean and will presumably reduce impingement and entrainment by a similar proportion. Because closed-cycle systems will almost always result in condenser cooling water temperatures higher than those found in a comparable once-through system, wet towers will increase the operating heat rates at Units 1 and 2, thereby decreasing the facility's overall efficiency. Additional power will also be consumed by the tower fans and circulating pumps.

As a PWR facility, DCPP is generally limited in how it can respond to these changes. While fossil fuel facilities may be able to increase the amount of fuel consumed to compensate for any shortfall, the complexities of a nuclear-fueled steam-generating unit and the inherent safety precautions that govern its operation generally preclude DCPP from increasing the thermal input to the system. Thus, any compensation for the reduced output must be obtained from other facilities on the grid.

Depending on the fuel source and efficiency of the facility providing the additional electricity, emissions for pollutants such as PM_{10}, SO_x, and NO_x may increase. The towers themselves will constitute a new source of PM_{10} emissions and require DCPP to obtain the necessary permits from the local AQMD/APCD. The annual mass of PM_{10} emissions will largely depend on the utilization capacity of the generating units the tower serves, but would likely approach their maximum values because DCPP is a baseload facility.

If DCPP retains its NPDES permit to discharge wastewater to the Pacific Ocean with a wet cooling tower system, it may have to address revised effluent limitations resulting from the substantial change in the quantity and characteristics of the discharge. Impacts from the discharge of elevated-temperature wastes associated with the current once-through system, if any, will be minimized by using a wet cooling system.

3.4.1 AIR EMISSIONS

Drift volumes from wet cooling towers are expected to be within the range of 0.5 gallons for every 100,000 gallons of circulating water in the towers. At DCPP, this corresponds to a rate of approximately 8.6 gpm based on the maximum combined flow in the two towers. The relative distances of the wet cooling towers from most facility structures (Figure C–6) do not appear to create any immediate concern over the effects of salt deposition on the switchyard or other sensitive equipment. Depending on the relocation of parking areas and other structures, drift is likely to be considered more of a nuisance rather than a threat to public health or safety, and will manifest itself as a whitish coating on exposed surfaces.

Total PM_{10} emissions from the DCPP cooling towers are a function of the number of hours in operation, overall water quality in the tower, and the evaporation rate of drift droplets prior to deposition on the ground. Makeup water at DCPP will be obtained from the same source currently used for once-through cooling water (Pacific Ocean). At 1.5 cycles of concentration and assuming an initial Total Dissolved Solids (TDS) value of 35 parts per thousand (ppt), the water within the cooling towers will reach a maximum TDS level of roughly 53 ppt. Any drift droplets exiting the tower will have the same TDS concentration.

As a nuclear facility, DCPP does not emit significant quantities of PM_{10}, SO_x, CO_2, or NO_x from its current operations. The emission of PM_{10} in substantial quantity from the wet cooling towers is likely to trigger enforcement of air quality regulations and may require PG&E to obtain necessary operating permits from the San Luis Obispo County Air Pollution Control District (APCD). Table C–9 summarizes the estimated drift and PM_{10} emissions from the DCPP wet cooling towers.[4]

Table C–9. Full Load Drift and Particulate Estimates

	PM_{10} (lbs/hr)	PM_{10} (tons/year)	Drift (gpm)	Drift (lbs/hr)
Tower 1	113	496	4.3	2,158
Tower 2	113	496	4.3	2,158
Total DCPP PM_{10} and drift emissions	**226**	**992**	**8.6**	**4,316**

3.4.2 MAKEUP WATER

The volume of makeup water required by the cooling tower at DCPP is the sum of evaporative loss and the blowdown volume required to maintain the circulating water in the tower at the design TDS concentration. Drift expelled from the tower represents an insignificant volume by comparison and is accounted for by rounding up estimates of evaporative losses. Makeup water volumes are based on design conditions, and may fluctuate seasonally depending on climate conditions and facility operations. Use of wet cooling towers will reduce once-through cooling water withdrawals from the Pacific Ocean by approximately 96 percent over the current design intake capacity (Table C–10).

Table C–10. Makeup Water Demand

	Tower circulating flow (gpm)	Evaporation (gpm)	Blowdown (gpm)	Total makeup water (gpm)
Tower 1	862,690	12,600	25,000	37,400
Tower 2	862,690	12,600	25,000	37,400
Total DCPP makeup water demand	**1,725,380**	**25,200**	**50,000**	**74,800**

The existing circulating water pumps are rated at 433,500 gpm while makeup water demand is only 37,400 per unit. In this case, the difference between these two values makes it unlikely that the existing pumps can be repurposed for use with the new system. The design developed for DCPP includes four new circulating water new circulating water pumps (two per unit) rated at 30,000 gpm each.

The existing once-through cooling system at DCPP does not treat water withdrawn from the Pacific Ocean, with the exception of screening for debris and larger organisms and periodic

[4] Conservative estimate assuming all dissolved solids present in drift will be converted to PM_{10}. Studies suggest this may overestimate actual emission rates (Chapter 4).

chlorination to control biofouling in the condenser tubes. Conversion to a wet cooling tower system will not interfere with chlorination operations.

Makeup water will continue to be withdrawn from the Pacific Ocean.

The wet cooling tower system proposed for DCPP includes water treatment for standard operational measures, i.e., fouling and corrosion control. Chemical treatment allowances are included in annual O&M costs. It is assumed that the current once-through cooling water quality will be acceptable for use in a seawater cooling tower (with continued screening and chlorination) and will not require any pretreatment to enable its use.

3.4.3 NPDES PERMIT COMPLIANCE

At maximum operation, wet cooling towers at DCPP will result in an effluent discharge of approximately 72 mgd of blowdown in addition to other in-plant waste streams, such as regeneration wastes, boiler blowdown, and treated sanitary wastes. These low-volume wastes may add an additional 20 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, DCPP will be required to modify its existing individual wastewater discharge (NPDES) permit.

Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES permit CA0003751 as implemented by CCRWQCB Order 90-09.[5]

DCPP will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities (40 CFR 423.13(d)(1)). These ELGs set numeric limitations for chromium and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity). Because ELGs are technology-based limitations, mixing zones or dilution factors are not applicable when determining compliance; limits must be met at the point of discharge from the cooling tower prior to commingling with any other waste stream. ELGs for cooling tower blowdown target priority pollutants that are contributed by maintenance chemicals and do not apply when limits may be exceeded as a result of background concentrations or other sources. Further discussion can be found in Chapter 4, Section 3.6.

Conversion to wet cooling towers will alter the volume and composition of a facility's wastewater discharge because wet towers concentrate certain pollutants in the effluent waste stream. The cooling towers designed for DCPP operate at 1.5 cycles of concentration, i.e., the blowdown discharge will contain a dissolved solids concentration 50 percent higher than the makeup water.

Changes to discharge composition may affect compliance with water quality objectives included in the Ocean Plan. If compliance with these objectives becomes problematic, alternative treatment or discharge methods may be necessary. Compliance may be achieved by altering the discharge configuration in such a way as to increase dilution (e.g., diffuser ports), or by seeking a mixing zone and dilution credits as permissible under the Ocean Plan. Alternately, some low volume

[5] Order 90-09 has been administratively continued pending adoption of a new order.

waste streams (e.g., boiler blowdown, laboratory drains) may be diverted, with necessary permits, for treatment at a POTW.

If more pollutant-specific treatment methods, such as filtration or precipitation technologies, become necessary to meet WQBELs, the initial capital cost may range from $2 to $5.50 per 1,000 gallons of treatment capacity, with annual costs of approximately $0.5 per gallon of capacity, depending on the method of treatment (FRTR 2002). Hazardous material disposal fees and permits would further increase costs.

This evaluation did not include alternative discharge or effluent treatment measures in the conceptual design because the variables used to determine final WQBELs, which would be used to determine the type and scope of the desired compliance method, cannot be quantified here. Likewise, the final cost evaluation (Section 4.0) does not include any allowance for these possibilities.

Thermal discharge standards are based on narrative criteria established for discharges to coastal waters under the Thermal Plan, which requires that existing discharges of elevated-temperature wastes comply with effluent limitations necessary to assure the protection of designated beneficial uses. The CCRWQCB proposed to implement this provision by establishing a maximum discharge temperature of no more than 22º F in excess of the temperature of the receiving water during normal operations (CCRWQCB 2003).

Because cooling tower blowdown will be taken from the “cold” side of the tower, conversion to a wet cooling system will produce a maximum discharge temperature of approximately 78º F. This temperature might actually be higher than the existing discharge during some seasonal periods, but the thermal plume’s areal extent into the Pacific Ocean west of the discharge cove will be substantially reduced with wet cooling towers.

3.4.4 RECLAIMED WATER

The use of reclaimed or alternative water sources could potentially eliminate all surface water withdrawals at DCPP. Doing so would completely eliminate impingement and entrainment concerns, and might enable the facility to avoid possible effluent quality and permit compliance issues, depending on the quality of reclaimed water available for use. In addition, wet cooling towers using reclaimed water would be expected to have lower PM_{10} emissions due to the lower TDS levels.

The California State Water Resources Control Board (SWRCB), in 1975, issued a policy statement requiring the consideration of alternative cooling methods in new power plants, including the use of reclaimed water, over the use of freshwater (SWRCB 1975). There is no similar policy regarding the use of marine waters, but the clear preference of state agencies is to encourage alternative cooling methods, including the use of reclaimed water, wherever possible.

This study did not pursue a detailed investigation of the use of reclaimed water because the conversion of the DCPP once-through cooling system to saltwater cooling towers enables the facility to meet the performance targets for impingement and entrainment impact reductions outlined in the 2006 California Ocean Protection Council (OPC) Resolution on Once-Through Cooling Water (see Chapter 1). In addition, the available volume of water in the vicinity of DCPP is approximately 8 mgd (Figure C–7). This volume would be able to provide less than one-fifth of the makeup requirement for freshwater towers at DCPP (50 mgd).

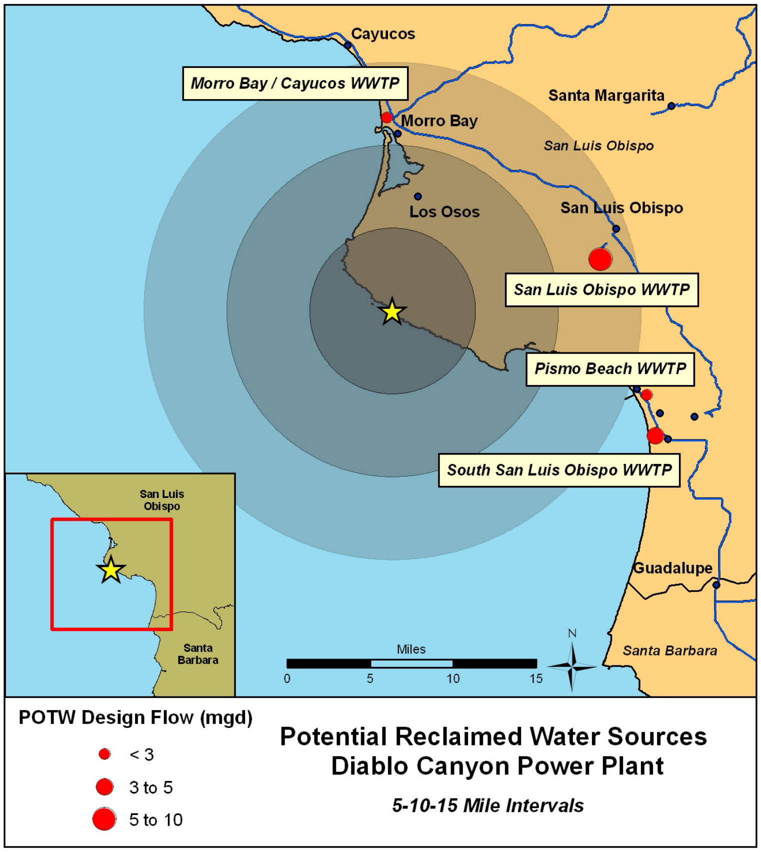

Figure C–7. Reclaimed Water Sources

3.4.5 THERMAL EFFICIENCY

The use of wet cooling towers at DCPP will increase the temperature of the condenser inlet water by 17 to 20° F above the surface water temperature, depending on the ambient wet bulb temperature at the time. The generating units at DCPP are designed to operate at the conditions described in Table C–11. The resulting monthly difference between once-through and wet cooling tower condenser inlet temperatures at DCPP is described in Figure C–8.

Table C–11. Design Thermal Conditions

	Unit 1	Unit 2
Design backpressure (in. HgA)	1.5	1.5
Design water temperature (°F)	60	60
Turbine inlet temp (°F) [a]	520	520
Turbine inlet pressure (psia) [a]	800	800
Full load heat rate (BTU/kWh)	10,000	10,000

[a] CEC 2006b.

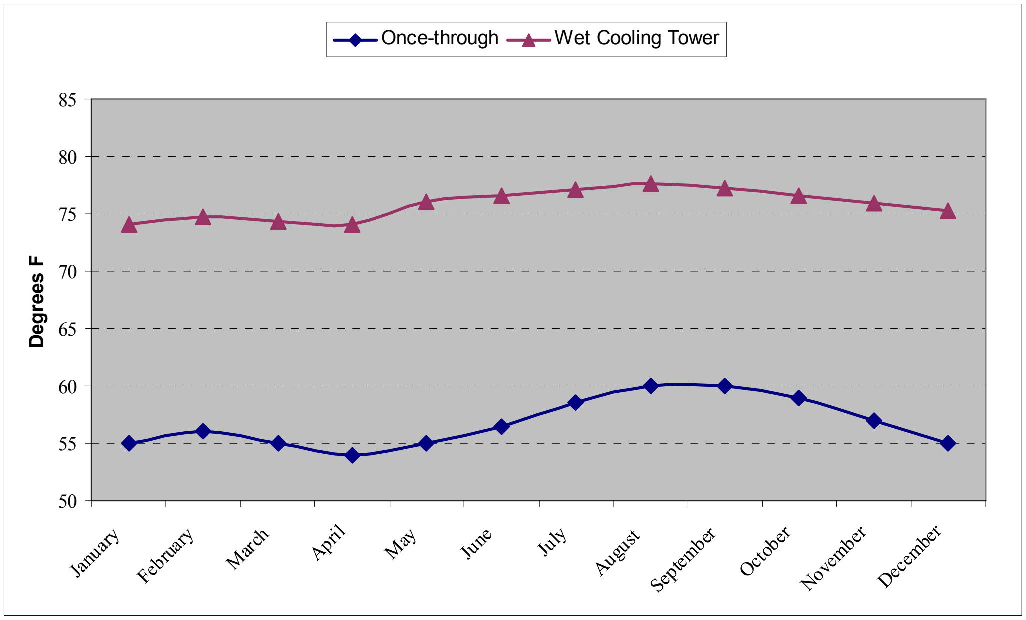

Figure C–8. Condenser Inlet Temperatures

Backpressures for the once-through and wet cooling tower configurations were calculated using the design criteria described in the sections above on a monthly basis using ambient climate data. In general, backpressures associated with the wet cooling tower were elevated by 0.90 to 1.05 inches HgA compared with the current once-through system (Figure C–9 and Figure C–11).

Heat rate adjustments were calculated by comparing the theoretical change in available energy that occurs at different turbine exhaust backpressures, assuming the thermal load and turbine inlet pressure remain constant, i.e., at the maximum load rating.[6] The relative change at different backpressures was compared with the value calculated for the design conditions (i.e., at design turbine inlet and exhaust backpressures) and plotted as a percentage of the maximum operating heat rate (Table C–11) to develop estimated correction curves (Figure C–10 and Figure C–12). A comparison was then made between the relative heat rates of the once-through and wet cooling

[6] Changes in thermal efficiency estimated for DCPP are based on the design specifications provided by the facility or obtained from other studies. This may not reflect system modifications that influence actual performance. In addition, the operating protocols used by DCPP or other restrictions may result in different conclusions.

systems for a given month. The difference between these two values represents the net increase in heat rate that would be expected in a converted system.

Table C–12 summarizes the annual average heat rate increase for each unit as well as the increase associated with the peak demand period of July-August-September. Monthly values were used to develop an estimate of the monetized value of these heat rate changes (Section 4.6.2). Month-by-month calculations are presented in Appendix A.

Table C–12. Summary of Estimated Heat Rate Increases

	Unit 1	Unit 2
Peak (July-August-September)	3.60%	3.60%
Annual average	3.61%	3.61%

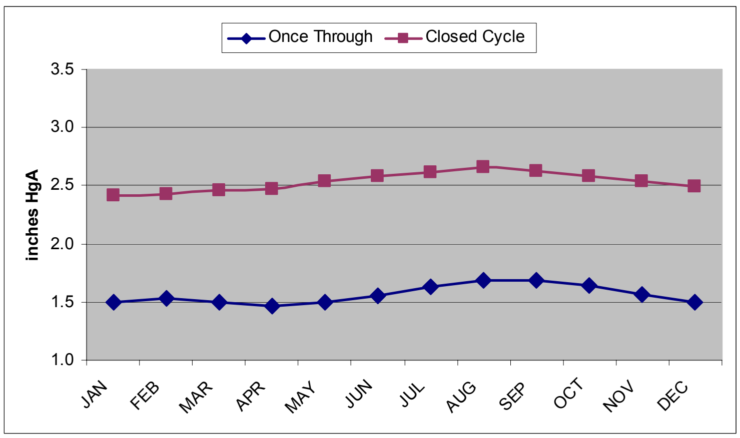

Figure C–9. Estimated Backpressures (Unit 1)

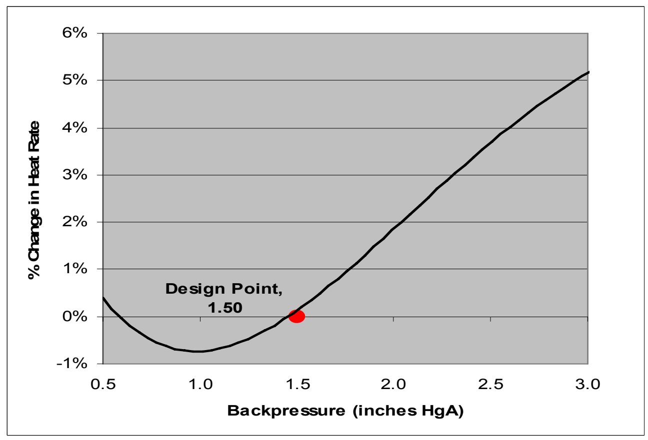

Figure C–10. Estimated Heat Rate Correction (Unit 1)

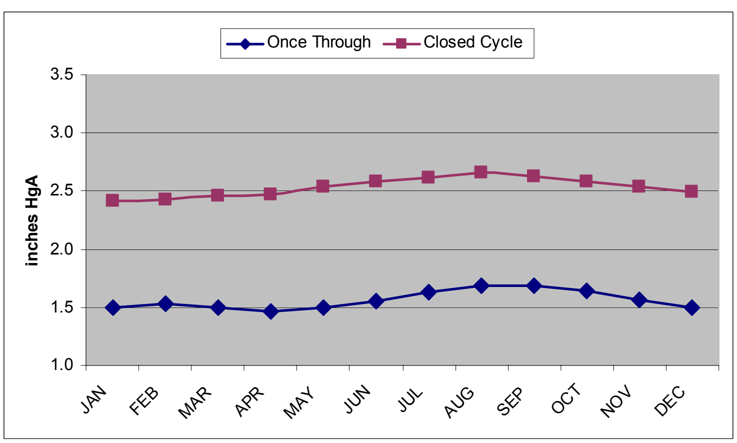

Figure C–11. Estimated Backpressures (Unit 2)

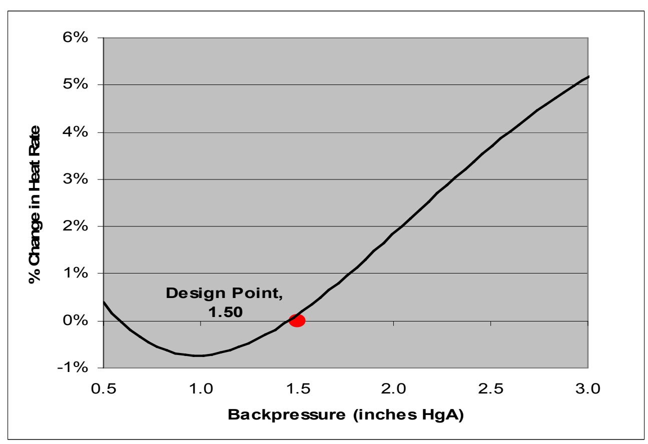

Figure C–12. Estimated Heat Rate Correction (Unit 2)

4.0 RETROFIT COST ANALYSIS

The wet cooling system retrofit estimate for DCPP is based on incorporating conventional wet cooling towers as a replacement for the existing once-through system. Standard cost elements for this project include the following:

- Direct (cooling tower installation, civil/structural, mechanical, piping, electrical, and demolition)
- Indirect (smaller project costs not itemized)
- Contingency (allowance for unknown project variables)
- Operations and maintenance (non–energy related cooling tower operations)
- Energy penalty (includes increased parasitic use from fans and pumps as well as decreased thermal efficiency)
- Revenue loss from shutdown (net loss in revenue during construction phase)

The methodology used to develop cost estimates is discussed in Chapter 5.

4.1 COOLING TOWER INSTALLATION

Table C–13 summarizes the design-and-build cost estimate for each tower developed by vendors, inclusive of all labor and management required for its installation.

Table C–13. Wet Cooling Tower Design-and-Build Cost Estimate

	Unit 1	Unit 2	DCPP total
Number of cells	52	52	**104**
Cost/cell ($)	586,538	586,538	**586,538**
Total DCPP D&B Cost ($)	**30,500,000**	**30,500,000**	**61,000,000**

4.2 OTHER DIRECT COSTS

A significant portion of the cost incurred for the wet cooling tower installation results from the various support structures and materials (pipes, pumps, etc.), as well the necessary equipment and labor required to prepare the cooling tower site and connect the towers to the cooling system. At DCPP, these costs comprise approximately 88 percent of the initial capital cost. Line item costs are detailed in Appendix B.

Deviations from or additions to the general cost elements discussed in Chapter 5 are discussed below. Other direct costs (non–cooling tower) are summarized in Table C–14.

4.2.1 CIVIL, STRUCTURAL, AND PIPING

The significant distances at which the cooling towers must be placed from their respective units (approximately 1,200 feet for each complex), and the large size of the pipes (144 inches), represent substantial increases in cost over other facilities. In total, the cooling tower configurations developed for DCPP require more than 15,000 feet of supply and return piping.

4.2.2 MECHANICAL AND ELECTRICAL

Initial capital costs in this category reflect incorporating new pumps (8 total) to circulate cooling water between the tower and condenser. Four new pumps (2 per unit) are required to provide makeup water from the Pacific Ocean. Electrical costs are based on the battery limit after the main feeder breakers.

4.2.3 DEMOLITION/OTHER

Costs in this category are based on an estimate from the 2002 Tetra Tech report and escalated to 2007 dollars using a factor of 4 percent per year. It covers mainly clearing, grubbing, leveling, road works, partial excavation of existing hillside, general landscaping, demolition of existing warehouse, installation of new warehouse, demolition of existing hazardous material warehouse, installation of new hazardous material warehouse, retaining wall and other miscellaneous civil works. Also includes a start-up water holding tank (120 ft diameter x 40 ft high) including 2 supply pumps and piping.

Table C–14. Summary of Other Direct Costs

	Equipment ($)	Bulk material ($)	Labor ($)	DCPP total ($)
Civil/structural/piping	25,100,000	105,000,000	68,300,000	**198,400,000**
Mechanical	19,810,000	0	1,600,000	**21,410,000**
Electrical	3,500,000	6,800,000	6,000,000	**16,300,000**
Demolition/other	0	0	212,700,000	**212,700,000**
Total DCPP other direct costs	**48,410,000**	**111,800,000**	**288,600,000**	**448,810,000**

4.3 INDIRECT AND CONTINGENCY

Indirect costs are calculated as 30 percent of all direct costs (civil/structural, mechanical, electrical, demolition, and cooling towers). An additional allowance is included for reinforcement of the condenser to withstand the increased pressures resulting from incorporating wet cooling towers. Each condenser may require reinforcement of the tube sheet bracing with 6-inch x 1-inch steel, and water box reinforcement/replacement with 5/8-inch carbon steel. Based on the data outlined in Chapter 5, a conservative estimate of 5 percent of all direct costs is included to account for possible condenser modifications. The location of the condensers (on the lower level of the turbine building) and the difficulty in accessing them for modifications may increase costs further, but cannot be evaluated within the scope of this study.

The contingency cost is calculated as 30 percent of the sum of all direct and indirect costs, including condenser reinforcement. At DCPP, potential costs in this category include relocation or demolition of small buildings and parking lots and the potential interference with underground structures, as well as the generally higher costs of construction projects at a secure nuclear facility. Disruption of coastal resources, if permitted, may require mitigation measures to allow the project to proceed. Soils were not characterized for this analysis. Initial capital costs are summarized in Table C–15.

Table C–15. Summary of Initial Capital Costs

	Cost ($)
Cooling towers	61,000,000
Civil/structural/piping	198,400,000
Mechanical	21,410,000
Electrical	16,300,000
Demolition	212,700,000
Indirect cost	152,900,000
Condenser modification	25,500,000
Contingency	206,500,000
Total DCPP capital cost	**894,710,000**

4.4 SHUTDOWN

A significant portion of the work relating to installing wet cooling towers can be completed without major disruption to operations. The principal disruption to the output of one or both units will result from the time and complexity of condenser reinforcements and the time needed to integrate the new cooling system and conduct acceptance testing.

For DCPP, a conservative estimate of 8 months per unit was developed. As a baseload facility, DCPP is typically operational 90 to 95 percent of the year; the difference between "low" and "high" output months is not significant. Thus, the period selected for shutdown is based on the time of year when DCPP is "least" critical to the grid. The lost revenue estimate for DCPP is based on the average replacement cost for the month(s) of shutdown (October through May), less the estimated cost of generation for a nuclear facility ($/MWh).[7] The estimated revenue loss for DCPP is $727 million and summarized in Table C–16.

Table C–16. Estimated Revenue Loss from Construction Shutdown

Estimated output (MWh)	Production savings ($/MWh)	Replacement cost ($/MWh)	Gross generation cost ($)	Revenue loss ($)
10,091,030	12	84	847,646,520	**726,554,160**

[7] The importance of DCPP to the overall reliability of the grid would likely require any cooling system conversion to be conducted in alternate years for Unit 1 and Unit 2. The existing cooling system's configuration, however, likely precludes a staggered conversion. The compact nature of operations at DCPP would require both units to be offline at the same time.

This analysis did not consider shutdown with respect to the required availability of a particular generating unit, nor can it automatically be assumed that the generating profile for 2006 will be the same in each subsequent year. Net output data from 2006 may not reflect any contractual obligations that mandate a particular unit's availability during a given time period.

4.5 OPERATIONS AND MAINTENANCE

O&M costs for a wet cooling tower system at DCPP include routine maintenance activities, chemicals and treatment systems to control fouling and corrosion in the towers, management and labor, and an allowance for spare parts and replacement. Annual costs are calculated based on the circulating water flow capacity of the towers using a base cost of $4.00/gpm in Year 1 and $5.80/gpm in Year 12, with an annual escalator of 2 percent (USEPA 2001). Year 12 costs increase based on the assumption that maintenance needs, particularly for spare parts and replacements, will be greater for years 12–20. Annual O&M costs, based on the design circulating water flow for both cooling towers at DCPP (1,725,380 gpm), are presented in Table C–17. These costs reflect maximum operation.

Table C–17. Annual O&M Costs (Full Load)

	Year 1 ($)	Year 12 ($)
Management/labor	1,725,380	2,501,801
Service/parts	2,760,608	4,002,882
Fouling	2,415,532	3,502,521
Total DCPP O&M cost	**6,901,520**	**10,007,204**

4.6 ENERGY PENALTY

The energy penalty is divided into two components: increased parasitic use resulting from the additional electrical demand of cooling tower fans and pumps; and the decrease in thermal efficiency resulting from elevated turbine backpressure values. As discussed in Section 3.4.5, it is unlikely that DCPP will be able to alter operations to compensate for the shortfall in electricity production resulting from the energy penalty; any changes to generation output will be absorbed as a direct loss of revenue.

The energy penalty for DCPP is calculated by first estimating the increased parasitic demand from the cooling tower pumps and fans, expressed as a percentage of the rated capacity of the particular unit(s). Likewise, the change in the unit's heat rate is also expressed as a capacity percentage. The sum of these values represents the percentage reduction in revenue-generating electricity DCPP will be able to produce with a wet cooling tower system.

4.6.1 INCREASED PARASITIC USE (FANS AND PUMPS)

As a baseload facility with an annual capacity utilization average of 85 percent or greater, DCPP will likely require the maximum cooling capacity of the wet cooling towers when the generating units are operational. During cooler periods of the year, DCPP may be able to take one or more cooling tower cells offline and still obtain the required cooling level. This would also reduce the fans' cumulative electrical demand. For the purposes of this study, however, operations are evaluated at the design conditions, i.e., maximum load; no allowance is made for seasonal changes. The increased electrical demand associated with operation of the cooling tower fans is summarized in Table C–18.

Table C–18. Cooling Tower Fan Parasitic Use

	Tower 1	Tower 2	DCPP total
Units served	Unit 1	Unit 2	--
Generating capacity (MW)	1,100	1,100	**2,200**
Number of fans (one per cell)	52	52	**104**
Motor power per fan (hp)	211	211	--
Total motor power (hp)	10,947	10,947	**21,895**
MW total	8.16	8.16	**16.33**
Fan parasitic use (% of capacity)	**0.74%**	**0.74%**	**0.74%**

The addition of new circulating water pump capacity for the wet cooling towers will also increase the parasitic use of electricity at DCPP. Makeup water will continue to be withdrawn from the Pacific Ocean through the use of one of the existing circulating water pumps; the remaining pumps will be retired. The net increase in pump-related parasitic usage is the difference between the new wet cooling tower configuration (new plus retained pumps) and the existing once-through configuration. Because one of the main design assumptions maintains the existing flow rate through each condenser, the new circulating pumps are single speed and are assumed to operate at their full rated capacity. The increased electrical demand associated with operating the cooling tower pumps is summarized in Table C–19.

Table C–19. Cooling Tower Pump Parasitic Use

	Tower 1	Tower 2	DCPP total
Units served	Unit 1	Unit 2	--
Generating capacity (MW)	1100	1100	**2,200**
Existing pump configuration (hp)	22,000	22,000	**44,000**
New pump configuration (hp)	31,727	31,727	**63,455**
Difference (hp)	9,727	9,727	**19,455**
Difference (MW)	7.3	7.3	**14.5**
Net pump parasitic use (% of capacity)	**0.66%**	**0.66%**	**0.66%**

4.6.2 HEAT RATE CHANGE

Adjustments to the heat rate were calculated based on the ambient conditions for each month and reflect the estimated difference between operations with once-through and wet cooling tower systems. As noted above, DCPP will absorb the financial loss associated with the reduction in revenue-generating electricity and must purchase electricity to makeup for the shortfall. The monthly percentage changes in the heat rate for each unit at DCPP are presented in Figure C–13 and Figure C–14.

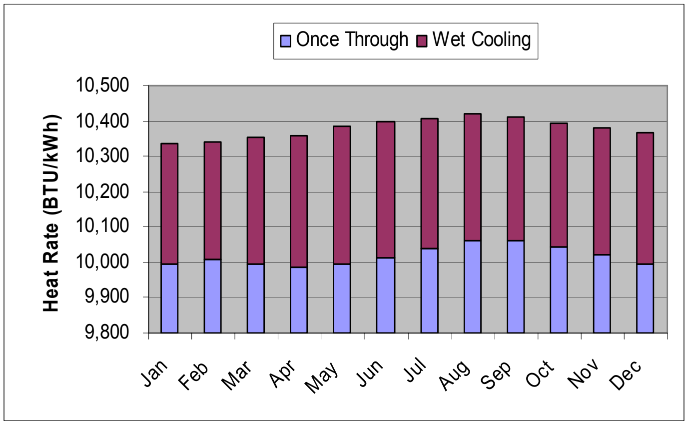

Figure C–13. Estimated Heat Rate Change (Unit 1)

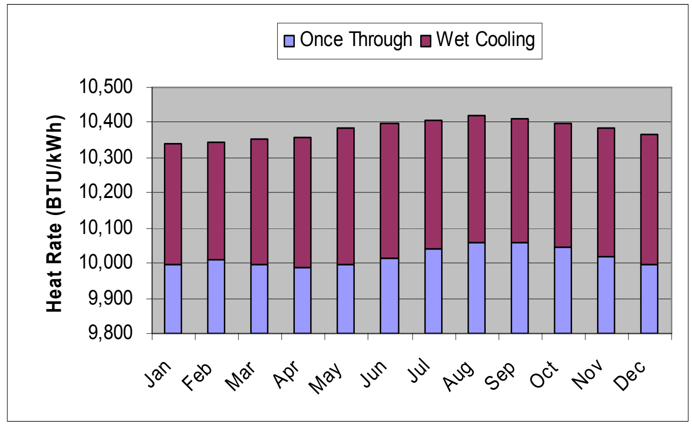

Figure C–14. Estimated Heat Rate Change (Unit 2)

4.6.3 CUMULATIVE ESTIMATE

The cost of the energy penalty for DCPP is calculated by first summing the three components of the penalty (efficiency + fan + pump), expressed as a percentage of the capacity, and multiplying this value by the net generation for each month. This yields the relative amount of revenue-generating electricity, expressed as MWh, that will be lost as a result of converting the once-through cooling system to wet cooling towers. The monthly cost is calculated using the average annual replacement cost ($84/MWh) obtained from the PG&E 2006 annual report. Based on 2006 net output, the monetary value of the annual energy penalty for DCPP will be approximately $78 million in Year 1. Table C–20 and Table C–21 summarize the Year 1 energy penalty estimates for each unit.

Table C-20. Unit 1 Energy Penalty—Year 1

Month	Replacement cost ($/MWh)	Net 2006 Generation (MWh)	Energy penalty				Generation shortfall (MWh)	Net Cost ($)
			Efficiency (%)	Fan (%)	Pump (%)	Total (%)		
January	84.00	847,824	3.41	0.74	0.66	4.81	40,758	3,423,630
February	84.00	769,878	3.34	0.74	0.66	4.74	36,524	3,068,025
March	84.00	852,983	3.58	0.74	0.66	4.98	42,464	3,567,009
April	84.00	821,001	3.72	0.74	0.66	5.12	42,064	3,533,403
May	84.00	851,047	3.86	0.74	0.66	5.26	44,749	3,758,897
June	84.00	820,642	3.83	0.74	0.66	5.23	42,956	3,608,327
July	84.00	851,443	3.67	0.74	0.66	5.08	43,220	3,630,452
August	84.00	848,275	3.61	0.74	0.66	5.01	42,471	3,567,579
September	84.00	822,566	3.53	0.74	0.66	4.93	40,538	3,405,174
October	84.00	847,638	3.50	0.74	0.66	4.90	41,550	3,490,193
November	84.00	763,086	3.63	0.74	0.66	5.03	38,405	3,225,999
December	84.00	848,600	3.68	0.74	0.66	5.08	43,137	3,623,498
							Unit 1 total	**41,902,186**

Table C-21. Unit 2 Energy Penalty—Year 1

Month	Replacement cost ($/MWh)	Net 2006 Generation (MWh)	Energy penalty				Generation shortfall (MWh)	Net Cost ($)
			Efficiency (%)	Fan (%)	Pump (%)	Total (%)		
January	84.00	807,355	3.41	0.74	0.66	4.81	38,812	3,260,211
February	84.00	733,397	3.34	0.74	0.66	4.74	34,793	2,922,645
March	84.00	812,347	3.58	0.74	0.66	4.98	40,441	3,397,077
April	84.00	413,505	3.72	0.74	0.66	5.12	21,186	1,779,632
May	84.00	85,573	3.86	0.74	0.66	5.26	4,500	377,958
June	84.00	822,891	3.83	0.74	0.66	5.23	43,074	3,618,216
July	84.00	850,282	3.67	0.74	0.66	5.08	43,161	3,625,502
August	84.00	844,957	3.61	0.74	0.66	5.01	42,305	3,553,624
September	84.00	818,645	3.53	0.74	0.66	4.93	40,345	3,388,942
October	84.00	846,614	3.50	0.74	0.66	4.90	41,500	3,485,976
November	84.00	818,899	3.63	0.74	0.66	5.03	41,214	3,461,953
December	84.00	665,535	3.68	0.74	0.66	5.08	33,831	2,841,816
							Unit 2 total	**35,713,552**

4.7 NET PRESENT COST

The net present cost (NPC) of a wet cooling system retrofit at DCPP is the sum of all annual expenditures over the 20-year life span of the project, discounted according to the year in which the expense is incurred and the selected discount rate. The NPC represents the total change in revenue streams, in 2007 dollars, that DCPP can expect over 20 years as a direct result of converting to wet cooling towers. The following values were used to calculate the NPC at a 7 percent discount rate:

- *Capital and Start-up.* Includes all capital, indirect, contingency, and shutdown costs. All costs in this category are incurred in Year 0. (See Table C–15 and Table C–16.)
- *Annual O&M*. Base cost values for Year 1 and Year 12 are adjusted for subsequent years using a 2 percent year-over-year escalator. Because DCPP is a baseload facility and operates at a relatively high capacity utilization factor, O&M costs for the NPC calculation were estimated at 100 percent of their maximum value. (See Table C–17.)
- *Annual Energy Penalty.* As a baseload facility, DCPP can be expected to operate at a high capacity utilization rate over its remaining life span. This study uses the 5-year average MWh output (2001–2006) as the basis for calculating the energy penalty in Years 1 through 20, including a year-over-year wholesale price escalation of 5.8 percent (based on the Producer Price Index). (See Table C–20 and Table C–21.)

Using these values, the NPC_{20} for DCPP is \$3,021 million. Appendix C contains detailed annual calculations used to develop this cost.

4.8 ANNUALIZED COST

The annual cost incurred by DCPP for the retrofit of the once-through cooling system is the sum of the annual amortized capital cost plus the annual average of O&M and energy penalty expenditures. Capital costs are amortized at a 7 percent discount rate over 20 years. O&M and energy penalty costs are calculated in the same manner as for the NPC_{20} (Section 4.7). Construction-related revenue losses are not amortized over the life of the project. This cost is incurred in Year 0 only. For DCPP, the estimated shutdown loss equals \$727 million.

Table C–22. Annual Cost

Discount rate (%)	Capital (\$)	Annual O&M (\$)	Annual energy penalty (\$)	Annual cost (\$)
7.00%	84,500,000	9,100,000	140,200,000	**233,800,000**

4.9 COST-TO-GROSS REVENUE COMPARISON

Financial data available to conduct a detailed analysis of the economic impact that a wet cooling system retrofit will have on annual revenues for SGS are limited. As an investor-owned utility, PG&E's gross revenues will include costs for transmission and distribution in addition to the cost of generation. An approximation of gross annual revenues was calculated using public data sources (US EIA 2005) listing PG&E's average annual retail rate at $125/MWh. This rate was applied to the monthly net generating output for each unit in 2006 (CEC 2006) to arrive at a facility-wide revenue estimate. This estimate does not reflect seasonal adjustments that may translate to higher or lower per-MWh retail rates through the year, nor does it include other liabilities such as taxes, operational costs, or other fixed revenue requirements.

The estimated gross revenue for DCPP is summarized in Table C–23. A comparison of annual costs to annual gross revenue is summarized in Table C–24.

Table C–23. Estimated Gross Revenue

	Retail rate ($/MWh)	Net generation (MWh)		Estimated gross revenue ($)		
		Unit 1	Unit 2	Unit 1	Unit 2	DCPP total
January	125	847,824	807,355	105,978,000	100,919,375	**206,897,375**
February	125	769,878	733,397	96,234,750	91,674,625	**187,909,375**
March	125	852,983	812,347	106,622,875	101,543,375	**208,166,250**
April	125	821,001	413,505	102,625,125	51,688,125	**154,313,250**
May	125	851,047	85,573	106,380,875	10,696,625	**117,077,500**
June	125	820,642	822,891	102,580,250	102,861,375	**205,441,625**
July	125	851,443	850,282	106,430,375	106,285,250	**212,715,625**
August	125	848,275	844,957	106,034,375	105,619,625	**211,654,000**
September	125	822,566	818,645	102,820,750	102,330,625	**205,151,375**
October	125	847,638	846,614	105,954,750	105,826,750	**211,781,500**
November	125	763,086	818,899	95,385,750	102,362,375	**197,748,125**
December	125	848,600	665,535	106,075,000	83,191,875	**189,266,875**
	DCPP total	**9,944,983**	**8,520,000**	**1,243,122,875**	**1,065,000,000**	**2,308,122,875**

Table C–24. Annualized Cost-to-Gross Revenue Comparison

Estimated gross annual revenue ($)	Initial capital		O&M		Energy penalty		Total annual cost	
	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross
2,308,100,000	84,500,000	3.7	9,100,000	0.4	140,200,000	6.1	**233,800,000**	**10.1**

5.0 OTHER TECHNOLOGIES

Within the scope of this study, and using the OPC resolution's stated goal of reducing impingement and entrainment by 90–95 percent as a benchmark, the effectiveness of other technologies commonly used to address such impacts could not be conclusively determined for use at DCPP. As with many existing facilities, the location and configuration of the site complicates the use of some technologies that might be used successfully elsewhere. A more detailed analysis that also comprises a biological evaluation may determine the applicability of one or more of these technologies to DCPP. A brief summary of the applicability of these technologies follows.

5.1 MODIFIED RISTROPH SCREENS—FINE MESH

The principal concern with this technology is the successful return of viable organisms captured on the screens to the source water body. The 2002 Tetra Tech report evaluated the feasibility of fine-mesh traveling screens at DCPP and noted the limited performance data available from studies at other facilities. The performance data that do exist show a high degree of variability that reflects the site and species-specific nature of this technology. Because fine-mesh screens have a smaller total open area per square foot than coarse-mesh screens, significant modifications to the screenhouse would be necessary to accommodate the larger screen assemblies. Tetra Tech estimated that these modifications would require the shutdown of both generating units for 13 months.

In proposed Order RB3-2003-009, the CCRWQCB considered fine-mesh screens to be an experimental technology, particularly at facilities with very large intake volumes. Further, the order states "the only way to determine the effectiveness of a screening technology at DCPP is to conduct site-specific research" (CCRWQCB 2003).

5.2 BARRIER NETS

Barrier nets are unproven in an open ocean environment. As noted above, the CCRWQCB does not consider impingement impacts to be significant enough to warrant installing control measures to reduce impingement mortality.

5.3 AQUATIC FILTRATION BARRIERS

Aquatic filtration barriers (AFBs) are unproven in an open ocean environment. The 2002 Tetra Tech report evaluated AFBs at DCPP but concluded that they are infeasible due to the heavy surf that can occur during winter storms (20 to 30 foot swells) and the massive size of the AFB necessary to screen the volume of water at DCPP. At DCPP, a barrier encompassing approximately 4 acres in surface area would be deployed in the open ocean. With an average depth of 20 feet, the AFB would be approximately 8,000 feet long.

5.4 VARIABLE SPEED DRIVES

Variable speed drives (VSDs) were not considered for this analysis because DCPP, as a baseload facility, would not be able to realize any significant flow reduction through their use.

5.5 CYLINDRICAL FINE-MESH WEDGEWIRE

Fine-mesh cylindrical wedgewire screens have not been deployed or evaluated at open coastal facilities for applications as large as required at DCPP (approximately 2,500 mgd). To function as intended, cylindrical wedgewire screens must be submerged in a water body with a consistent ambient current of 0.5 fps. Ideally, this current would be unidirectional so that screens may be oriented properly and any debris impinged on the screens will be carried downstream when the airburst cleaning system is activated.

Placement of intake screens in the existing intake cove is impractical because the available area and ambient currents are insufficient for the 30 to 35 screen assemblies that would be required for DCPP, depending on the screen diameter and mesh size. Locating the screens offshore, if a relatively close area could be identified, would leave the screens vulnerable to damage from winter storms. For these reasons, combined with the rocky and steeply sloping bathymetry offshore, fine-mesh wedgewire screens are impractical for use at DCPP.

6.0 REFERENCES

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Appendix A. Once-Through and Closed-Cycle Thermal Performance

		Unit 1			Unit 2		
		Once through	Closed cycle	Net increase	Once through	Closed cycle	Net increase
JAN	Backpressure (in. HgA)	1.49	2.41	**0.92**	1.49	2.41	**0.92**
	Heat rate Δ (%)	*-0.03*	*3.38*	***3.41***	*-0.03*	*3.38*	***3.41***
FEB	Backpressure (in. HgA)	1.53	2.43	**0.90**	1.53	2.43	**0.90**
	Heat rate Δ (%)	*0.08*	*3.42*	***3.34***	*0.08*	*3.42*	***3.34***
MAR	Backpressure (in. HgA)	1.49	2.46	**0.97**	1.49	2.46	**0.97**
	Heat rate Δ (%)	*-0.03*	*3.55*	***3.58***	*-0.03*	*3.55*	***3.58***
APR	Backpressure (in. HgA)	1.46	2.47	**1.02**	1.46	2.47	**1.02**
	Heat rate Δ (%)	*-0.13*	*3.59*	***3.72***	*-0.13*	*3.59*	***3.72***
MAY	Backpressure (in. HgA)	1.49	2.54	**1.05**	1.49	2.54	**1.05**
	Heat rate Δ (%)	*-0.03*	*3.83*	***3.86***	*-0.03*	*3.83*	***3.86***
JUN	Backpressure (in. HgA)	1.55	2.58	**1.04**	1.55	2.58	**1.04**
	Heat rate Δ (%)	*0.14*	*3.97*	***3.83***	*0.14*	*3.97*	***3.83***
JUL	Backpressure (in. HgA)	1.63	2.61	**0.99**	1.63	2.61	**0.99**
	Heat rate Δ (%)	*0.39*	*4.06*	***3.67***	*0.39*	*4.06*	***3.67***
AUG	Backpressure (in. HgA)	1.69	2.65	**0.97**	1.69	2.65	**0.97**
	Heat rate Δ (%)	*0.59*	*4.20*	***3.61***	*0.59*	*4.20*	***3.61***
SEP	Backpressure (in. HgA)	1.69	2.63	**0.94**	1.69	2.63	**0.94**
	Heat rate Δ (%)	*0.59*	*4.12*	***3.53***	*0.59*	*4.12*	***3.53***
OCT	Backpressure (in. HgA)	1.65	2.58	**0.93**	1.65	2.58	**0.93**
	Heat rate Δ (%)	*0.45*	*3.95*	***3.50***	*0.45*	*3.95*	***3.50***
NOV	Backpressure (in. HgA)	1.57	2.54	**0.97**	1.57	2.54	**0.97**
	Heat rate Δ (%)	*0.19*	*3.83*	***3.63***	*0.19*	*3.83*	***3.63***
DEC	Backpressure (in. HgA)	1.49	2.49	**1.00**	1.49	2.49	**1.00**
	Heat rate Δ (%)	*-0.03*	*3.65*	***3.68***	*-0.03*	*3.65*	***3.68***

Note: Heat rate delta represents change from design value calculated according to estimated ambient conditions for each month.

Appendix B. Itemized Capital Costs

Line item description	Unit	Qty	Equipment		Bulk material		Labor			Total Cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Labor rate ($/hr)	Total price ($)	
CIVIL/STRUCTURAL/PIPING										
Concrete slabs on grade (all in)	m3	29,228		0	200	5,845,600	4	75	8,768,400	14,614,000
Concrete basin walls (all in)	m3	993		0	225	223,425	8	75	595,800	819,225
Concrete elevated slabs (all in)	m3	567		0	250	141,750	10	75	425,250	567,000
Concrete for transformers and oil catch basin (allocation)	m3	200		0	250	50,000	10	75	150,000	200,000
Fencing around transformers	m	50		0	30	1,500	1	75	3,750	5,250
Structural steel for building	t	350		0	2,500	875,000	20	105	735,000	1,610,000
Building architectural (siding, roofing, doors, painting…etc)	ea	1		0	420,000	420,000	5000	75	375,000	795,000
PCCP pipe 144" diam.	ft	15,600		0	1,820	28,392,000	5	95	7,410,000	35,802,000
PCCP pipe 72" diam. Make-up water line	ft	1,000		0	507	507,000	1.3	95	123,500	630,500
Bend for PCCP pipe 144" diam. (allocation)	ea	160		0	75,000	12,000,000	180	95	2,736,000	14,736,000
Bend for PCCP pipe 72" diam (allocation)	ea	10		0	18,000	180,000	40	95	38,000	218,000
Harness clamp 144" c/w internal testable joint	ea	1,400		0	5,275	7,385,000	30	95	3,990,000	11,375,000
Harness clamp 72" c/w internal testable joint	ea	55		0	2,440	134,200	18	95	94,050	228,250
Allocation for trust blocks	lot	1		0	50,000	50,000	500	95	47,500	97,500
Bedding for PCCP pipe	m3	53,940		0	25	1,348,500	0.04	200	431,520	1,780,020
Excavation for PCCP pipe	m3	173,920		0	0	0	0.04	200	1,391,360	1,391,360
Backfill for PCCP pipe (reusing excavated material)	m3	63,907		0	0	0	0.04	200	511,256	511,256
Ductile iron cement pipe 12" diam. for fire water line	ft	1,500		0	100	150,000	0.6	95	85,500	235,500
Excavation and backfill for fire line & make-up (using excavated material for backfill except for bedding)	m3	9,809		0		0	0.08	200	156,944	156,944
Allocation for pipe racks (approx 800 ft) and cable racks	t	80		0	2,500	200,000	17	105	142,800	342,800
Foundations for pipe racks and cable racks	m3	190		0	250	47,500	8	75	114,000	161,500
Allocation for sheet piling and dewatering	lot	1		0	500,000	500,000	5000	100	500,000	1,000,000
Allocation for testing pipes	lot	1		0		0	2000	95	190,000	190,000
Flange for PCCP joints 144"	ea	14		0	68,000	952,000	75	95	99,750	1,051,750
Flange for PCCP joints 30"	ea	104		0	2,260	235,040	16	95	158,080	393,120
Piles	ft	108,000		0	25	2,700,000	0.1	100	1,080,000	3,780,000
FRP pipe 30" diam.	ft	500			121	60,639	0.4	106	21,200	81,839
FRP pipe 96" diam.	ft	320			2,838	908,160	1.75	106	59,360	967,520
FRP pipe 120" diam.	ft	1,500		0	4,257	6,385,500	2	106	318,000	6,703,500
Joint for FRP pipe 96" diam.	ea	16			17,974	287,584	600	106	1,017,600	1,305,184

Line item description	Unit	Qty	Equipment		Bulk material		Labor			Total Cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Labor rate ($/hr)	Total price ($)	
Joint for FRP pipe 120" diam.	ea	100		0	22,562	2,256,210	1200	106	12,720,000	14,976,210
Riser (FRP pipe 30" diam X 55 ft)	ea	104		0	15,350	1,596,400	150	106	1,653,600	3,250,000
Butterfly valves 30" c/w allocation for actuator & air lines	ea	108	30,800	3,326,400		0	50	106	572,400	3,898,800
Butterfly valves 96" c/w allocation for actuator & air lines	ea	8	151,200	1,209,600		0	75	106	63,600	1,273,200
Butterfly valves 120" c/w allocation for actuator & air lines	ea	48	252,000	12,096,000		0	80	106	407,040	12,503,040
Butterfly valves 72" c/w allocation for actuator & air lines	ea	4	96,600	386,400		0	75	106	31,800	418,200
Butterfly valves 144" c/w allocation for actuator & air lines	ea	14	429,000	6,006,000		0	100	106	148,400	6,154,400
Check valves 30"	ea	2	44,000	88,000		0	16	106	3,392	91,392
Check valves 72"	ea	2	138,000	276,000		0	32	106	6,784	282,784
Check valves 96"	ea	8	216,000	1,728,000		0	40	106	33,920	1,761,920
Allocation for Tie-Ins to condenser's piping	lot	1		0	1,000,000	1,000,000	16000	106	1,696,000	2,696,000
FRP flange 30"	ea	324		0	1,679	544,045	50	106	1,717,200	2,261,245
FRP flange 72"	ea	8		0	20,888	167,101	200	106	169,600	336,701
FRP flange 96"	ea	40		0	40,000	1,600,000	500	106	2,120,000	3,720,000
FRP flange 120"	ea	116		0	236,500	27,434,000	1200	106	14,755,200	42,189,200
Allocation for other accessories (bends, water hammers…)	lot	1		0	500,000	500,000	4000	106	424,000	924,000
TOTAL CIVIL / STRUCTURAL / PIPING										**198,487,110**
MECHANICAL										
Cooling tower for Unit 1	lot	2	30,500,000			0		Incl.		30,500,000
Cooling tower for Unit 2	lot	0	30,500,000	0		0		Incl.		30,500,000
Pump 4160 V 2000 HP	ea	4	1,000,000	4,000,000		0	500	106	212,000	4,212,000
Pump 4160 V 7000 HP	ea	8	1,870,000	14,960,000		0	1200	106	1,017,600	15,977,600
Overhead crane 50 ton in (in pump house) Including additional structure to reduce the span	ea	1	650,000	650,000		0	1300	106	137,800	787,800
Allocation for ventilation of buildings	ea	1	200,000	200,000		0	2000	106	212,000	412,000
TOTAL MECHANICAL										**82,389,400**
ELECTRICAL/INSTRUMENTATION										
Local feeder for 200 HP motor 460 V (up to MCC)	ea	104		0	18,000	1,872,000	150	106	1,653,600	3,525,600
Local feeder for 7000 HP motor 4160 V (up to MCC)	ea	8		0	60,000	480,000	250	106	212,000	692,000
Allocation for lighting and lightning protection	lot	1		0	300,000	300,000	3000	106	318,000	618,000
Lighting & electrical services for pump house building	ea	1		0	140,000	140,000	2000	106	212,000	352,000
Allocation for automation and control	lot	1		0	2,000,000	2,000,000	20000	106	2,120,000	4,120,000
Primary breaker(xxkV)	ea	4	45,000	180,000		0	60	106	25,440	205,440

Line item description	Unit	Qty	Equipment		Bulk material		Labor			Total Cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Labor rate ($/hr)	Total price ($)	
Oil Transformer 20MVA xx-4.16kV	ea	2	350,000	700,000		0	200	106	42,400	742,400
Dry Transformer 2MVA xxkV-480V	ea	16	100,000	1,600,000		0	100	106	169,600	1,769,600
4.16kV switchgear	lot	1	500,000	500,000		0	300	106	31,800	531,800
480V Switchgear - 1 breaker 3000A	ea	16	30,000	480,000		0	80	106	135,680	615,680
Primary feed cabling (assumed 13.8 kv)	m	7,500		0	175	1,312,500	0.5	106	397,500	1,710,000
4.16 kv cabling feeding MCC's	m	3,000		0	75	225,000	0.4	106	127,200	352,200
460 volt cabling feeding MCC's	m	2,500		0	70	175,000	0.4	106	106,000	281,000
Allocation for cable trays and duct banks	m	4,000		0	75	300,000	1	106	424,000	724,000
TOTAL ELECTRICAL/INSTRUMENTATION										**16,239,720**
DEMOLITION/OTHER										
Various civil works that are not included above. The price is based on an estimate from the 2002 study performed by Hatch and escalated to 2007 using a factor of 4%/year. It covers mainly clearing, grubbing, leveling, road works, partial excavation of existing hillside, general landscaping, demolition of existing warehouse, installation of new warehouse, demolition of existing hazardous material warehouse, installation of new hazardous material warehouse, retaining wall and also miscellaneous work.										209,037,945
Start-up water holding tank (120 ft diameter X 40 ft high) including 2 supply pumps and piping (price based on 2002 estimate escalated to 2007 at 4%/year)										3,649,959
TOTAL DEMOLITION/OTHER										**212,687,904**

Appendix C. Net Present Cost Calculation

Project year	Capital/start-up ($)	O & M ($)	Energy penalty ($)		Total ($)	Annual discount factor	Present value ($)
			Unit 1	Unit 2			
0	1,621,254,160	--	--	--	1,621,254,160	1	**1,621,254,160**
1	--	6,901,520	41,902,184	35,713,551	84,517,255	0.9346	**78,989,827**
2	--	7,039,550	44,345,082	37,795,651	89,180,283	0.8734	**77,890,059**
3	--	7,180,341	46,930,400	39,999,137	94,109,879	0.8163	**76,821,894**
4	--	7,323,948	49,666,442	42,331,087	99,321,478	0.7629	**75,772,355**
5	--	7,470,427	52,561,996	44,798,989	104,831,412	0.7130	**74,744,797**
6	--	7,619,836	55,626,360	47,410,770	110,656,966	0.6663	**73,730,737**
7	--	7,772,232	58,869,377	50,174,818	116,816,428	0.6227	**72,741,590**
8	--	7,927,677	62,301,462	53,100,010	123,329,149	0.5820	**71,777,565**
9	--	8,086,231	65,933,637	56,195,741	130,215,609	0.5439	**70,824,269**
10	--	8,247,955	69,777,568	59,471,953	137,497,476	0.5083	**69,889,967**
11	--	8,412,914	73,845,600	62,939,167	145,197,682	0.4751	**68,983,419**
12	--	10,207,348	78,150,799	66,608,521	154,966,668	0.4440	**68,805,200**
13	--	10,411,495	82,706,990	70,491,798	163,610,283	0.4150	**67,898,267**
14	--	10,619,725	87,528,808	74,601,469	172,750,002	0.3878	**66,992,451**
15	--	10,832,119	92,631,737	78,950,735	182,414,592	0.3624	**66,107,048**
16	--	11,048,762	98,032,168	83,553,563	192,634,492	0.3387	**65,245,303**
17	--	11,269,737	103,747,443	88,424,736	203,441,916	0.3166	**64,409,711**
18	--	11,495,132	109,795,919	93,579,898	214,870,948	0.2959	**63,580,314**
19	--	11,725,034	116,197,021	99,035,606	226,957,661	0.2765	**62,753,793**
20	--	11,959,535	122,971,307	104,809,382	239,740,224	0.2584	**61,948,874**
Total							**3,021,161,600**

D. EL SEGUNDO GENERATING STATION

EL SEGUNDO POWER, LLC—EL SEGUNDO, CA

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Appendices

1.0 GENERAL SUMMARY

Retrofitting the existing once-through cooling system at El Segundo Generating Station (ESGS) with closed-cycle wet cooling towers poses several significant challenges with respect to potential siting locations and conflicts with local use restrictions. The facility's compact dimensions, the layout of existing structures and the site's proximity to state beaches limit the different wet cooling tower configurations that could be evaluated. In addition, the location of ESGS approximately 2 miles south-southwest of Los Angeles International Airport makes it likely that plume abatement would be necessary to prevent interference with airport operations. Plume-abated cooling towers, therefore, are the preferred option for ESGS.

Despite the probability that plume-abated towers would be required at ESGS, a workable configuration could not be developed. The limited available space at the site coupled with local zoning ordinances restricts the placement of large towers in the facility's southernmost portion. Based on input for other development projects at ESGS, the El Porto community in neighboring Manhattan Beach would likely object to 50–60 foot tall towers located so close to the boundary.

Based on these factors, the preferred option for ESGS is considered logistically infeasible.

If plume-abatement cooling towers were not required, a conventional tower design could be configured at the existing location. The cooling tower configuration designed under the alternative option complies with all identified local use restrictions and includes necessary mitigation measures, where applicable.

The discussion in this chapter, and all cost estimates, evaluates the alternative design based on conventional cooling towers.

1.1 COST

Initial capital and net present costs associated with the installation and operation of wet cooling towers at ESGS are summarized in Table D–1. Annualized costs based on 20-year average values for the various cost elements are summarized in Table D–2. A detailed cost analysis is presented in Section 4.0 of this chapter.

Table D–1. Cumulative Cost Summary

Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Total capital and start-up [a]	78,100,000	13.31	127
NPC_{20} [b]	91,000,000	15.50	147

[a] Includes all costs associated with the construction and installation of cooling towers and shutdown loss, if any.
[b] NPC_{20} includes all capital costs, operation and maintenance costs, and energy penalty costs over 20 years discounted at 7 percent.

Table D–2. Annual Cost Summary

Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Capital and start-up [a]	7,400,000	1.26	11.99
Operations and maintenance	400,000	0.07	0.65
Energy penalty	900,000	0.15	1.46
Total ESGS annual cost	**8,700,000**	**1.48**	**14.10**

[a] Does not include revenue loss associated with shutdown, if any, which is incurred in Year 0 only.

1.2 ENVIRONMENTAL

Environmental changes associated with a cooling tower retrofit for ESGS are summarized in Table D–3 and discussed further in Section 3.4.

Table D–3. Environmental Summary

		Unit 3	Unit 4
Water use	Design intake volume (gpm)	132,400	131,000
	Cooling tower makeup water (gpm)	7,000	7,000
	Reduction from capacity (%)	95	95
Energy efficiency [a]	Summer heat rate increase (%)	1.08	1.09
	Summer energy penalty (%)	2..07	2..08
	Annual heat rate increase (%)	1.01	1.03
	Annual energy penalty (%)	2..01	2..03
Direct air emissions [b]	PM_{10} emissions (tons/yr) (maximum capacity)	76.17	75.37
	PM_{10} emissions (tons/yr) (2006 capacity utilization)	8.81	7.13

[a] Reflects the comparative increase between once-through and wet cooling systems, but does not account for any operational changes to address the change in efficiency, such as increased fuel consumption (see Section 4.6).
[b] Reflects emissions from the cooling tower only; does not include any increase in stack emissions.

1.3 OTHER POTENTIAL FACTORS

As noted above, the preferred option is considered infeasible at this location.

The alternative option (conventional cooling towers) can only be sited alongside a recreational trail and state beaches. This placement has the effect of creating a 58-foot high wall running parallel to the beach for nearly 600 feet, from north to south. This may conflict with visual impact standards established by the Coastal Act. Further complicating this option is the towers' location relative to the switchyard, which would be immediately downwind and subject to the adverse effects of salt drift deposition. Siting constraints are discussed further in Section 3.2.3.

2.0 BACKGROUND

The El Segundo Generating Station (ESGS) is a natural gas–fired steam electric generating facility located in the city of El Segundo, Los Angeles County, owned and operated by El Segundo Power, LLC. ESGS currently operates two conventional steam turbine units (Unit 3 and Unit 4) with a combined generating capacity of 670 MW. Units 1 and 2 have been retired from service and are slated to be replaced with a dry cooled combined cycle unit. The facility occupies approximately 22 acres of a 33-acre industrial site bordering Dockweiler and Manhattan state beaches and Santa Monica Bay. The southern boundary of the property borders the city of Manhattan Beach. (See Table D–4 and Figure D–1.)

Table D–4. General Information

Unit	In-service year	Rated capacity (MW)	2006 capacity utilization [a]	Condenser cooling water flow (gpm)
Unit 3	1964	335	11.6%	132,400
Unit 4	1965	335	9.5%	131,000
ESGS Total		**670**	**10.5%**	**263,400**

[a] Quarterly Fuel and Energy Report—2006 (CEC 2006).

Figure D–1. General Vicinity of El Segundo Generating Station

2.1 COOLING WATER SYSTEM

ESGS operates one cooling water intake structure (CWIS) to provide condenser cooling water to the two generating units (Figure D–2). Once-through cooling water is combined with low-volume wastes generated by ESGS and discharged through a single submerged outfall to the Pacific Ocean located approximately 2,100 feet offshore at a depth of 20 feet. Surface water withdrawals and discharges are regulated by NPDES Permit CA0001147, as implemented by Los Angeles Regional Water Quality Control Board (LARWQCB) Order 00-084.[1]

Cooling water is obtained from the Pacific Ocean through a submerged intake conduit terminating 2,000 feet offshore at a depth of approximately 20 feet. The submerged end of the conduit is fitted with a velocity cap to minimize the entrainment of motile fish into the system by converting the vertical flow to a lateral flow, thus triggering a flight response from fish.

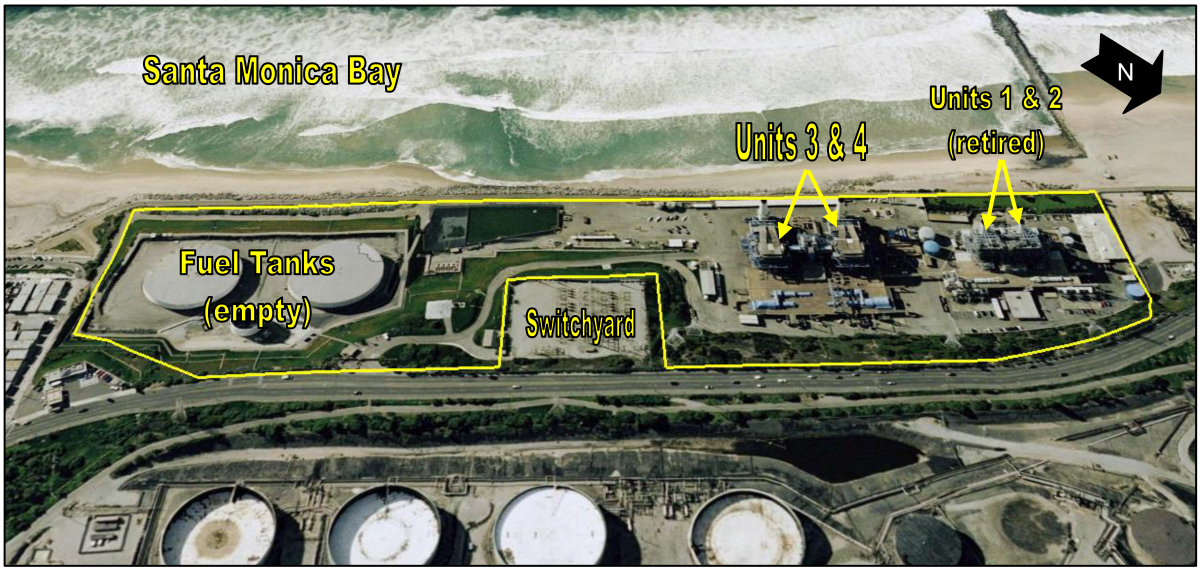

Figure D–2. Site View

The onshore portion of the CWIS comprises four screen bays, each fitted with a vertical traveling screen with 5/8-inch mesh panels. Screens rotate periodically for cleaning based on a pressure differential between the upstream and downstream faces of the screens. Screens are also rotated manually for 8 minutes during each 12-hour shift. A high-pressure spray removes any debris or fish that have become impinged on the screen face. Captured debris is collected in a dumpster for disposal in a landfill. Downstream of each screen is a circulating water pump rated at 69,200 gallons per minute (gpm), for a total facility capacity of 276,800 gpm, or 399 million gallons per day (mgd) (El Segundo Power 2005).

At maximum capacity, ESGS maintains a total pumping capacity rated at 398 mgd, with a condenser flow rating of 380 mgd. On an annual basis, ESGS withdraws substantially less than its design capacity due to its low generating capacity utilization (10.5 percent for 2006). When in

[1] LARWQCB Order 00-084 expired on May 10, 2005, but has been administratively extended pending adoption of a renewed order.

operation and generating the maximum load, ESGS can be expected to withdraw water from the Pacific Ocean at a rate approaching its maximum capacity.

2.2 SECTION 316(B) PERMIT COMPLIANCE

The CWIS currently in operation at ESGS uses a velocity cap to reduce the entrainment of motile fish through the system, although it is commonly thought of as an impingement reduction technology because it targets larger organisms. Velocity caps have been shown to reduce impingement rates when compared with a shoreline intake structure. Likewise, the location of the intake structure in an offshore setting may contribute to lower rates of entrainment when compared with a shoreline intake if the near-shore environment is more biologically productive. This study did not evaluate the effectiveness of either measure.

LARWQCB Order 00-084, adopted in 2000, states that “the design, construction and operation of the intake structure [at ESGS] was then considered Best Available Technology (BAT) [*sic*] as required by Section 316(b) of the Clean Water Act” (LARWQCB 2000, Finding 8). This finding was based on ecological studies conducted by Southern California Edison (previous owner) in 1982. The order does not contain any numeric or narrative limitations regarding impingement or entrainment resulting from CWIS operation, but does require bimonthly monitoring of impingement at each intake structure (coinciding with scheduled heat treatments). Based on the record available for review, ESGS has been compliant with this permit requirement.

The LARWQCB has notified ESGS of its intent to revisit requirements under CWA Section 316(b), including a determination of the best technology available (BTA) for minimization of adverse environmental impact, during the current permit reissuance process. A final decision regarding any Section 316(b)–related requirements has not been made as of the publication of this study.

3.0 WET COOLING SYSTEM RETROFIT

3.1 OVERVIEW

This study evaluates the use of saltwater wet cooling towers at ESGS, with the current source water (Pacific Ocean) continuing to provide makeup water to the facility. Conversion of the existing once-through cooling system to wet cooling towers will reduce the facility's current intake capacity by approximately 95 percent; rates of impingement and entrainment will decline by a similar proportion. Use of alternative water sources as a replacement for the once-through cooling water currently used at ESGS is a potentially feasible option based on the volume of secondary treated water available in the vicinity. In a wet cooling tower system, the use of reclaimed water as the makeup water source (as opposed to the Pacific Ocean) is an attractive alternative when considering additional benefits its use may provide, such as avoidance of conflicts with effluent limitations or air emission standards. Use of reclaimed water is discussed further in Section 3.4.4.

The configuration of the wet cooling towers—their size and location—were based on best professional judgment (BPJ) using the criteria outlined in Chapter 5 and designed to meet the performance benchmarks in the most cost-effective manner. Information not available to this study that offers a more complete characterization of the facility may lead to different conclusions regarding the physical configuration of the towers.

Based on a review of information provided by El Segundo Power, LLC, and obtained from public records, installation of wet cooling towers at ESGS poses several significant challenges. Space constraints, the facility's general layout, and local use restrictions concerning ambient noise limited the number of possible tower configurations available for evaluation. In addition, the proximity of Los Angeles International Airport (LAX) will likely require incorporating plume abatement technologies into any final tower design, but a workable configuration of plume-abated towers could not be developed for ESGS. The final design of conventional towers described below represents the most plausible installation that could be developed for the facility. Constraints on placement and design are discussed further in Section 3.2.3.

This study developed a conceptual design of wet cooling towers sufficient to meet the cooling demand for each active generating unit at ESGS at its rated output during peak climate conditions. Cost estimates are based on vendor quotes developed using the available information and the various design constraints identified at ESGS.

The overall practicality of retrofitting the two units at ESGS will require an evaluation of factors outside the scope of this study, such as the age and efficiency of the units and their role in the overall reliability of electricity production and transmission in California, particularly the Los Angeles region.

3.2 DESIGN BASIS

3.2.1 CONDENSER SPECIFICATIONS

For this study, the conceptual design of the cooling towers selected for ESGS is based on the assumption that the condenser flow rate and thermal load to each will remain unchanged from the current system. Although no provision is included to re-optimize the condenser performance for service with a cooling tower, some modifications to the condenser (tube sheet and water box reinforcement) may be necessary to handle the increased water pressures that will result from the increased total pump head required to raise water to the elevation of the cooling tower risers.[2] The practicality and difficulty of these modifications are dependent on the age and configuration of each unit, but are assumed to be feasible at ESGS. Condenser water boxes for both units are located at grade level and appear to be readily accessible. Additional costs associated with condenser modifications are included in the discussion of capital expenditures (Section 4.3).

Information provided by ESGS was largely used as the basis for the cooling tower design. In some cases, the data were incomplete or conflicted with values obtained from other sources. Where possible, questionable values were verified or corrected using other known information about the condenser. For example, the data sheets provided by ESGS show turbine exhaust pressures of 1.5 inches HgA for both units under design conditions, but they also list the steam condensate temperature as 93.8 ºF and 93.0 ºF for Units 3 and 4, respectively. These temperatures correspond to backpressure values of 1.60 and 1.56 inches HgA. Based on other information describing the condensers, it appears the reported steam condensate temperatures are correct. Thus, the design backpressure values for Units 3 and 4 used in this study are 1.6 and 1.56 inches HgA. Table D–5 summarizes the condenser design specifications for Units 3 and 4.

Table D–5. Condenser Design Specifications

	Unit 3	Unit 4
Thermal load (MMBTU/hr)	1,440	1,440
Surface area (ft^2)	174,000	172,000
Condenser flow rate (gpm)	132,400	131,000
Tube material	Cu-Ni (90-10)	Cu-Ni (90-10)
Heat transfer coefficient (U_d)	488	511
Cleanliness factor	0.85	0.85
Inlet temperature (°F)	63	63
Temperature rise (°F)	21.76	21.99
Steam condensate temperature (°F)	93.8	92.9
Turbine exhaust pressure (in. HgA)	1.6	1.56

[2] In this context, re-optimization refers to a comprehensive condenser overhaul that reduces thermal efficiency losses associated with a wet cooling tower's higher circulating water temperatures. Modifications discussed in this study are generally limited to reinforcement measures that enable the condenser to withstand increased water pressures.

3.2.2 AMBIENT ENVIRONMENTAL CONDITIONS

ESGS is located in Los Angeles County along the shoreline of the Pacific Ocean approximately 2 miles south-southwest of the south runway at LAX. Cooling water is withdrawn from a submerged offshore location in the Pacific Ocean. Inlet temperature data for 2005 were provided by ESGS and serve as the basis for monthly cooling water temperature values used in this study.

The wet bulb temperature used in the development of the overall cooling tower design was obtained from American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) publications. Data for Los Angeles at LAX indicate a 1 percent ambient wet bulb temperature of 69° F (ASHRAE 2006). An approach temperature of 12° F was selected based on the site configuration and vendor input. At the design wet bulb and approach temperatures, the cooling towers will yield "cold" water at a temperature of 81° F. Monthly maximum wet bulb temperatures used in the development of energy penalty estimates in Section 4.6 were calculated using data obtained from California Irrigation Management Information System (CIMIS) Monitoring Station 99 in Santa Monica (CIMIS 2006). Climate data used in this analysis are summarized in Table D–6.

Table D–6. Surface Water and Ambient Wet Bulb Temperatures

	Surface (°F)	Ambient wet bulb (°F)
January	59.2	54.3
February	60.3	56.1
March	61.5	57.7
April	63.1	60.7
May	66.0	65.7
June	68.0	68.3
July	71.4	69.3
August	72.2	69.4
September	67.0	65.5
October	63.5	60.3
November	62.0	56.3
December	60.7	55.5

3.2.3 LOCAL USE RESTRICTIONS

3.2.3.1 NOISE

Industrial development at ESGS is regulated by the City of El Segundo Municipal Code and the City of El Segundo Local Coastal Plan (LCP). Chapter 9.06 of the Municipal Code limits contributions from noise sources to 5 dBA above the ambient level for residential areas and 8 dBA above the ambient level for industrial areas. The proximity of the facility's southern boundary to the city of Manhattan Beach will also require compliance with Chapter 5.48 of that city's municipal code, which limits noise impacts in residential areas to an increase of no more than 2 dBA over ambient levels. Based on the areas available to place a wet cooling tower, this study used a noise limit of 65 dBA at a distance of 500 feet in selecting the design elements of the tower installation to comply with noise standards of each city's zoning code. Accordingly, the overall design of the wet cooling tower installation does not require any measures to specifically address noise, such as low-noise fans or barrier walls. A more detailed analysis of the potential impacts of noise on the surrounding areas was developed for the Final Staff Assessment (FSA) of the Application for Certification of the El Segundo Power Redevelopment (ESPR) project in 2002 (CEC 2002a).[3]

3.2.3.2 BUILDING HEIGHT

ESGS is located within the M2 industrial zone as described by the City of El Segundo Municipal Code, which limits the total height of structures to 200 feet. Because of the proximity of ESGS to state beaches and residential areas in Manhattan Beach, and the potential for a large cooling tower to impact visual resources, this study selected a height restriction of 60 feet above grade level. The height of the wet cooling towers designed for ESGS, from grade level to the top of the fan deck, is 58 feet.

3.2.3.3 PLUME ABATEMENT

Local zoning ordinances do not contain any specific criteria for addressing any impact associated with a wet cooling tower plume. The proximity of ESGS to LAX, however, may necessitate incorporating plume abatement measures. As shown in Figure D–1, ESGS is located approximately 2 miles south-southwest of the airport. Community standards for assessing the visual impact associated with a cooling tower plume cannot be determined within the scope of this study, but the proximity of residential areas in Manhattan Beach, which border the southern edge of the property, may also require plume abatement. Further consideration must be made for the proximity of any eventual cooling tower to coastal recreational areas and the potential visual impact on those resources. CEC siting guidelines and Coastal Act provisions evaluate the total size and persistence of a visual plume with respect to aesthetic standards for coastal resources; significant visual changes resulting from a persistent plume would likely be subject to additional controls.

Plume abatement towers were initially selected for evaluation at ESGS due to the likelihood they would be required to eliminate potential impact on operations at LAX. Further investigation and consultation with cooling tower vendors, however, indicated that plume-abated towers could not be located at the site given the constraints on available space that would preclude their construction. Accordingly, all towers evaluated for ESGS are of a conventional design.

3.2.3.4 DRIFT AND PARTICULATE EMISSIONS

Drift elimination measures that are considered best available control technology (BACT) are required for all cooling towers evaluated in this study, regardless of their location. State-of-the-art

[3] The application for certification for the ESPR was amended by El Segundo Power, LLC, in June 2007 to include dry cooling for the new units.

drift eliminators are included for each cooling tower cell at ESGS, with an accepted efficiency of 0.0005 percent. Because cooling tower PM_{10} emissions are a function of the rate of drift, drift eliminators are also considered BACT for PM_{10} emissions from wet cooling towers. This efficiency can be verified by a proper in situ test, which accounts for site-specific climate, water, and operating conditions. Testing based on the Isokinetic Drift Test Code published by the Cooling Tower Institute is only required at initial start-up on one representative cell of each tower for an approximate cost of $60,000 per test, or approximately $120,000 for both of the cooling towers at ESGS (CTI 1994). This cost is not itemized in the final analysis and is instead included as part of the indirect cost estimate (Section 4.3).

3.2.3.5 FACILITY CONFIGURATION AND AREA CONSTRAINTS

The configuration of the ESGS site, at only 22 acres and with no adjoining areas available for expansion, creates several challenges in selecting a location for wet cooling towers. As shown in Figure D–3, few areas are available that are large enough to accommodate wet cooling towers without the demolition and relocation of existing structures. Because the current site of Units 1 and 2 on the northern end of the property has been reserved for the ESPR project, this study limited consideration of potential sites to two areas on the southern end of the property (Area 1 and Area 2).

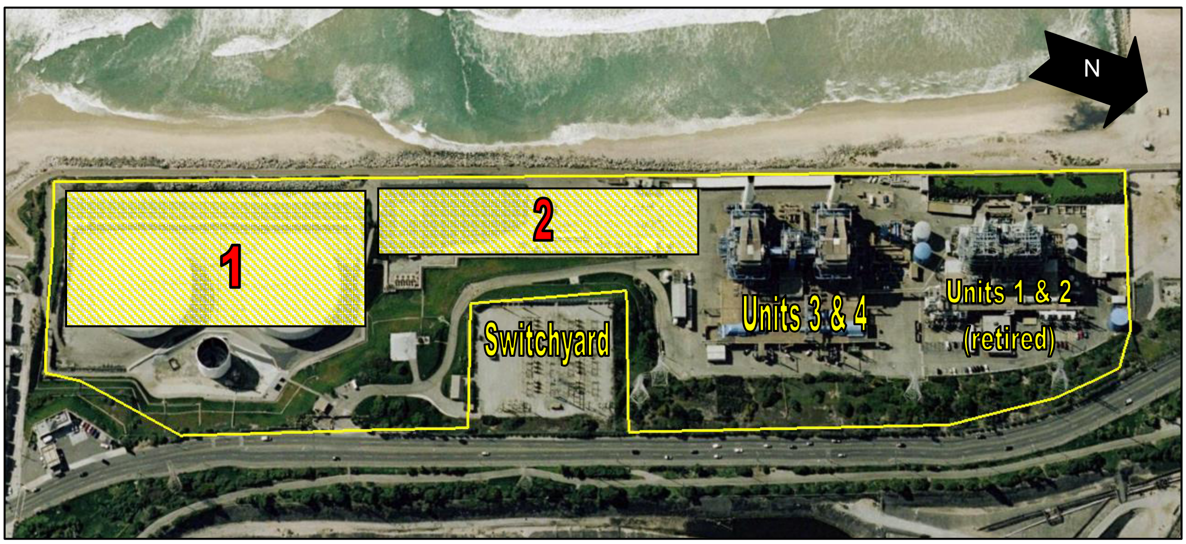

Figure D–3. Cooling Tower Siting Area

Demolition of the empty fuel tanks in Area 1 would create sufficient space for a more optimal cooling tower configuration, but this location would place the towers within a short distance of residential areas in Manhattan Beach and complicate compliance with noise ordinances. Furthermore, during the development of the ESPR project, residents of the El Porto community indicated their preference for the fuel tanks to remain to serve as a noise and visual buffer between the neighborhood and the generating units at ESGS (CEC 2002a). Replacement of the tanks with wet cooling towers would likely encounter significant local opposition.

Area 2 is a narrow strip between the Unit 3 and Unit 4 power block and the fuel tanks along the western boundary of the property with an approximate total area of 105,000 square feet (700 feet x 150 feet). The retention basin, used to treat in-plant wastes prior to discharge, currently occupies 30,000 square feet of this area and will have to be relocated or reconfigured to allow construction of the cooling towers. Further complicating the use of this area is the proximity of the beach and a recreational trail that parallels the western edge of ESGS. In this location, the base of the towers will be less than 50 feet from the recreational trail, with the towers rising 58 feet and running alongside the trail for approximately 570 feet. The visual impact created by the towers as seen from the beach may conflict with Coastal Act provisions that require protection of visual resources in coastal areas, although a final evaluation may weigh the relative impacts each option would create (i.e., continued use of once-through cooling versus visual impact of a wet cooling tower).

The switchyard, which juts into the center of the property, is located at an elevation of 70 feet above sea level, while grade level for Area 2 is approximately 20 feet. With prevailing winds from the west and northwest, the proximity of the switchyard to the towers and the elevation at which it is located will create a strong probability of interference with or damage to sensitive equipment resulting from salt drift deposition. Placement of wet cooling towers in this location will likely require relocation of the switchyard or replacement with gas insulated switchgear (GIS) to avoid these effects.

The difficulties surrounding the placement of conventional wet cooling towers at ESGS make incorporation of plume-abated towers at the site unlikely. Because plume-abated towers cannot be arranged in a back-to-back configuration and must be placed in an inline setup, these towers would be substantially longer than the total length of the two conventional towers selected for ESGS. Sufficient area for plume-abated towers might be available if Areas 1 and 2 were both available, but the use of Area 1 was eliminated from consideration, as discussed above.

Despite these limitations, Area 2 was selected as the most appropriate location for the placement of the wet cooling towers designed in this study.

3.3 CONCEPTUAL DESIGN

Based on the design constraints discussed above, two wet cooling towers were selected to replace the current once-through cooling system that currently serves Units 3 and 4 at ESGS. Each tower will operate independently and be dedicated to one unit. Each tower is configured in a multicell, back-to-back arrangement.

3.3.1 SIZE

Each tower is constructed over a concrete collection basin 4 feet deep. The basin is larger than the footprint of the tower structure, extending an additional 2 feet in each direction. The concrete used for construction is suitable for saltwater applications. The principal tower material is fiberglass reinforced plastic (FRP), with stainless steel fittings. These materials are more resistant to the higher corrosive effects of saltwater.

The size of each tower is primarily based on the thermal load rejected to the tower by the surface condenser and a 12° F approach to the ambient wet bulb temperature. Flow rates through each condenser remain unchanged.

General characteristics of the wet cooling towers selected for ESGS are summarized in Table D–7.

Table D–7. Wet Cooling Tower Design

	Tower 1 (Unit 3)	**Tower 2 (Unit 4)**
Thermal load (MMBTU/hr)	1,440	1,440
Circulating flow (gpm)	132,400	131,000
Number of cells	10	10
Tower type	Mechanical draft	Mechanical draft
Flow orientation	Counterflow	Counterflow
Fill type	Modular splash	Modular splash
Arrangement	Back-to-back	Back-to-back
Primary tower material	FRP	FRP
Tower dimensions (l x w x h) (ft)	270 x 108 x 58	270 x 108 x 58
Tower footprint with basin (l x w) (ft)	274 x 112	274 x 112

3.3.2 LOCATION

The initial site selection for each tower was based on the desire to locate each tower as close as possible to the respective generating units to minimize the supply and return pipe distances and any increases in total pump head and brake horsepower. Tower 1, serving Unit 3, is located at an approximate distance of 600 feet. Tower 2, serving Unit 4, is located at an approximate distance of 200 feet.

Figure D–4 identifies the approximate location of each tower and supply and return piping.

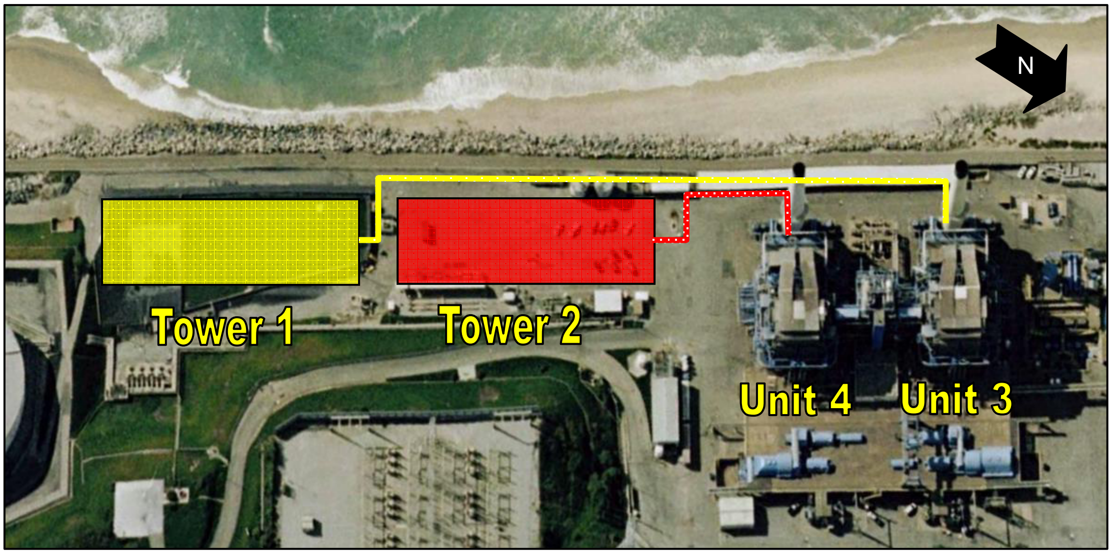

Figure D-4. Location of Cooling Towers

3.3.3 PIPING

The main supply and return pipelines for Tower 1 will be located underground and made of prestressed concrete cylinder pipe (PCCP) suitable for saltwater applications. These pipes range in size from 72 to 84 inches in diameter.

Pipes connecting the Unit 3 condenser to the supply and return lines are made of FRP and placed above ground on pipe racks. The proximity of Unit 4 to Tower 2 allows most pipes to be placed above ground on pipe racks (supply headers to the tower will be placed underground and made of PCCP). Above-ground placement avoids the potential disruption that may be caused by excavation in and around the power block. The condensers at ESGS are located at grade level, enabling a relatively straightforward connection.

Potential interference with underground obstacles and infrastructure is a concern, particularly at existing sites that are several decades old and have been substantially modified or rebuilt in the interim. Avoidance of these obstacles is considered to the degree practical in this study. Associated costs are included in the contingency estimate and are generally higher than similar estimates for new facilities (Section 4.3).

Appendix B details the total quantity of each pipe size and type for ESGS.

3.3.4 FANS AND PUMPS

Each tower cell uses an independent single-speed fan. The fan size and motor power are the same for each cell in both towers.

This analysis includes new pumps to circulate water between the condensers and cooling towers. Pumps are sized according to the flow rate for each tower, the relative distance between the tower and condensers, and the total head required to deliver water to the top of the cooling tower riser.

A separate, multilevel pump house is constructed for each cooling tower and is sized to accommodate the motor control centers (MCCs) and appropriate electrical switchgear. The electrical installation includes all necessary transformers, cabling, cable trays, lighting, and lightning protection. A 50-ton overhead crane is also included to allow for pump servicing.

Fan and pump characteristics associated with wet cooling towers at ESGS are summarized in Table D–8. The net electrical demand of the fans and new pumps are discussed further as part of the energy penalty analysis in Section 4.6.

Table D–8. Cooling Tower Fans and Pumps

		Tower 1 (Unit 3)	Tower 2 (Unit 4)
Fans	Number	10	10
	Type	Single speed	Single speed
	Efficiency	0.95	0.95
	Motor power (hp)	211	211
Pumps	Number	2	2
	Type	50% recirculating Mixed flow Suspended bowl Vertical	50% recirculating Mixed flow Suspended bowl Vertical
	Efficiency	0.88	0.88
	Motor power (hp)	1,619	1,619

3.4 ENVIRONMENTAL EFFECTS

Conversion of the existing once-through cooling system at ESGS to wet cooling towers will significantly reduce the intake of seawater from the Pacific Ocean and will presumably reduce impingement and entrainment by a similar proportion. Because closed-cycle systems will almost always result in condenser cooling water temperatures higher than those found in a comparable once-through system, wet towers will increase the operating heat rates at both of ESGS's steam units, thereby decreasing the facility's overall efficiency. Additional power will also be consumed by the operation of tower fans and circulating pumps. Depending on how ESGS chooses to address this change in efficiency, total stack emissions may increase for pollutants such as PM_{10}, SO_x, and NO_x and may require additional control measures or the purchase of emission credits to meet air quality regulations. No control measures are currently available for CO_2 emissions, which will increase, on a per-kWh basis, by the same proportion as any change in the heat rate. The towers themselves will constitute an additional source of PM_{10} emissions, the annual mass of which will largely depend on the utilization capacity for the generating units served by the tower.

If ESGS retains its National Pollutant Discharge Elimination System (NPDES) permit to discharge wastewater to the Pacific Ocean with a wet cooling tower system, it may have to address revised effluent limitations resulting from the substantial change in the quantity and characteristics of the discharge. Impacts from the discharge of elevated temperature wastes associated with the current once-through system, if any, will be minimized through the use of a wet cooling system.

3.4.1 AIR EMISSIONS

ESGS is located in the South Central Coast air basin. Air emissions are permitted by the South Coast Air Quality Management District (SCAQMD) (Facility ID 115663).

Drift volumes are expected to be within the range of 0.5 gallons for every 100,000 gallons of circulating water in the towers. At ESGS, this corresponds to a rate of approximately 1.3 gpm based on the maximum combined flow in the two towers. As discussed in Section 3.2.3, drift deposition has the potential to significantly impact the switchyard and transmission equipment.

Total PM_{10} emissions from the ESGS cooling towers are a function of the number of hours in operation, overall water quality in the tower, and evaporation rate of drift droplets prior to deposition on the ground. Makeup water at ESGS will be obtained from the same source currently used for once-through cooling water (Pacific Ocean). At 1.5 cycles of concentration and assuming an initial total dissolved solids (TDS) value of 35 parts per thousand (ppt), the water within the cooling towers will reach a maximum TDS level of roughly 53 ppt. Any drift droplets exiting the tower will have the same TDS concentration.

The cumulative mass emission of PM_{10} from ESGS will increase as a result of the direct emissions from the cooling towers themselves. Stack emissions of PM_{10}, as well as SO_x, NO_x, and other pollutants, will increase due to the drop in fuel efficiency, although the cumulative increase will depend on actual operations and emission control technologies currently in use. Maximum drift and PM_{10} emissions from the cooling towers are summarized in Table D–9.[4]

Data summarizing the total facility emissions for these pollutants in 2005 are presented in Table D–10 (CARB 2005). In 2005, ESGS operated at an annual capacity utilization of 11.3 percent. Using this rate, the additional PM_{10} emissions from the cooling towers would increase the facility total by approximately 17 tons/year, or 58 percent.[5]

[4] This is a conservative estimate that assumes all dissolved solids present in drift droplets will be converted to PM_{10}. Studies suggest this may overestimate actual emission profiles for saltwater cooling towers (Chapter 4).

[5] 2006 emission data are not currently available from the ARB website. For consistency, the comparative increase in PM_{10} emissions estimated here is based on the 2005 ESGS capacity utilization rate instead of the 2006 rate presented in Table D-4. All other calculations in this chapter use the 2006 value.

Table D-9. Full Load Drift and Particulate Estimates

	PM_{10} (lbs/hr)	PM_{10} (tons/year)	Drift (gpm)	Drift (lbs/hr)
Tower 1	17	76	0.66	331
Tower 2	17	75	0.66	328
Total ESGS PM_{10} and drift emissions	**34**	**151**	**1.32**	**659**

Table D-10. 2005 Emissions of SO_x, NO_x, PM_{10}

Pollutant	Tons/year
NO_x	31.2
SO_x	2.3
PM_{10}	29.4

3.4.2 MAKEUP WATER

The volume of makeup water required by the two cooling towers at ESGS is the sum of evaporative loss and the blowdown volume required to maintain the circulating water in the towers at the design TDS concentration. Drift expelled from the tower represents an insignificant volume by comparison and is accounted for by rounding up estimates of evaporative losses. Makeup water volumes are based on design conditions, and may fluctuate seasonally depending on climate conditions and facility operations. Use of wet cooling towers will reduce once-through cooling water withdrawals from the Pacific Ocean by approximately 95 percent over the current design intake capacity. (See Table D–11.)

Table D-11. Makeup Water Demand

	Tower circulating flow (gpm)	Evaporation (gpm)	Blowdown (gpm)	Total makeup water (gpm)
Tower 1	132,400	2,400	4,800	**7,200**
Tower 2	131,000	2,400	4,800	**7,200**
Total ESGS makeup water demand	**263,400**	**4,800**	**9,600**	**14,400**

One circulating water pump rated at 69,200 gpm, which is currently used to provide once-through cooling water to the facility, will be retained in a wet cooling system to provide makeup water to both cooling towers. The capacity of the retained pump exceeds the makeup demand capacity by approximately 55,000 gpm. Any excess capacity will be routed through a bypass conduit and returned to the wet well at a point located behind the intake screens. Recirculating the excess capacity in this manner reduces additional cost that would be incurred if new pumps were required to maintain the desired flow reduction. The intake of new water, measured at the intake screens, will be equal to the makeup water demand of the cooling towers. Figure D–5 presents a schematic of this configuration.

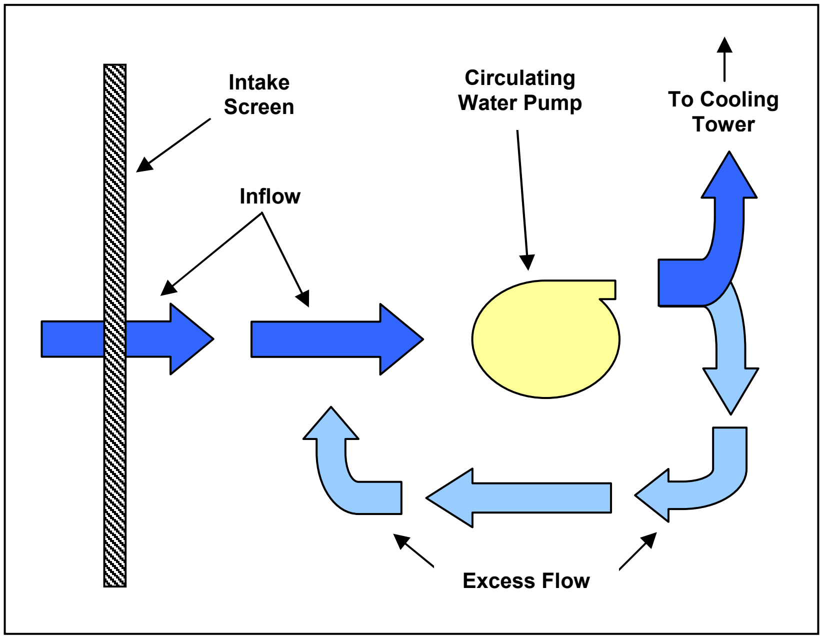

Figure D–5. Schematic of Intake Pump Configuration

The existing once-through cooling system at ESGS does not treat water withdrawn from the Pacific Ocean, with the exception of screening for debris and larger organisms and periodic chlorination to control biofouling in the condenser tubes. Heat treatments are also periodically used to control mussel growth on pipes and condenser tubes by raising the temperature of the circulating water to 125º F. Conversion to a wet cooling tower system will not interfere with chlorination or heat treatment operations.

Makeup water will continue to be withdrawn from the Pacific Ocean.

The wet cooling tower system proposed for ESGS includes water treatment for standard operational measures, i.e., fouling and corrosion control. Chemical treatment allowances are included in annual operations and maintenance (O&M) costs. It is assumed that the current once-through cooling water quality will be acceptable for use in a seawater cooling tower (with continued screening) and will not require any pretreatment to enable its use.

3.4.3 NPDES PERMIT COMPLIANCE

At maximum operation, wet cooling towers at ESGS will result in an effluent discharge of approximately 14 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, sanitary wastes, and cleaning wastes. These low-volume wastes may add an additional 1.1 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, ESGS will be required to modify its existing individual wastewater discharge (NPDES) permit. Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0001147, as implemented by LARWQCB Order 00-084. All wastewaters are discharged to the Pacific Ocean through a submerged conduit extending approximately 2,100 feet offshore. The existing order contains effluent limitations based on the 1997 Ocean Plan and 1972 Thermal Plan.

ESGS will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities (40 CFR 423.13(d)(1)). These ELGs set numeric limitations for chromium and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity). Because ELGs are technology-based limitations, mixing zones or dilution factors are not applicable when determining compliance; limits must be met at the point of discharge from the cooling tower prior to commingling with any other waste stream. ELGs for cooling tower blowdown target priority pollutants that are contributed by maintenance chemicals and do not apply when limits may be exceeded as a result of background concentrations or other sources. Further discussion can be found in Chapter 4, Section 3.6.

Conversion to wet cooling towers will alter the volume and composition of a facility's wastewater discharge because wet towers concentrate certain pollutants in the effluent waste stream. The cooling towers designed for ESGS operate at 1.5 cycles of concentration, i.e., the blowdown discharge will contain a dissolved solids concentration 50 percent higher than the makeup water.

Changes to discharge composition may affect compliance with water quality objectives included in the Ocean Plan. If compliance with these objectives becomes problematic, alternative treatment or discharge methods may be necessary. Compliance may be achieved by altering the discharge configuration in such a way as to increase dilution (e.g., diffuser ports), or by seeking a mixing zone and dilution credits as permissible under the Ocean Plan. Alternately, some low volume waste streams (e.g., boiler blowdown, laboratory drains) may be diverted, with necessary permits, for treatment at a POTW.

If more pollutant-specific treatment methods, such as filtration or precipitation technologies, become necessary to meet WQBELs, the initial capital cost may range from $2 to $5.50 per 1,000 gallons of treatment capacity, with annual costs of approximately $0.5 per gallon of capacity, depending on the method of treatment (FRTR 2002). Hazardous material disposal fees and permits would further increase costs.

This evaluation did not include alternative discharge or effluent treatment measures in the conceptual design because the variables used to determine final WQBELs, which would be used to determine the type and scope of the desired compliance method, cannot be quantified here. Likewise, the final cost evaluation (Section 4.0) does not include any allowance for these possibilities.

Thermal discharge standards are based on narrative criteria established for coastal discharges under the Thermal Plan, which requires existing discharges of elevated-temperature wastes to comply with effluent limitations necessary to assure the protection of designated beneficial uses. The LARWQCB has implemented this provision by establishing a maximum discharge temperature of 105º F during normal operations in Order 00-084 (LARWQCB 2000). Information available for review indicates ESGS has consistently been able to comply with this requirement. Because cooling tower blowdown will be taken from the "cold" side of the tower, conversion to a wet cooling system will significantly reduce the discharge temperature (to less than 81º F) and the size of any related thermal plume in the receiving water.

3.4.4 RECLAIMED WATER

The use of reclaimed or alternative water sources could potentially eliminate all surface water withdrawals at ESGS. Doing so would completely eliminate impingement and entrainment concerns, and might enable the facility to avoid possible effluent quality and permit compliance issues, depending on the quality of reclaimed water available for use. In addition, wet cooling towers using reclaimed water would be expected to have lower PM_{10} emissions due to the lower TDS levels. The SWRCB, in 1975, issued a policy statement requiring the consideration of alternative cooling methods in new power plants, including the use of reclaimed water, over the use of freshwater (SWRCB 1975). There is no similar policy regarding the use of marine waters, but the clear preference of state agencies is to encourage alternative cooling methods, including the use of reclaimed water, wherever possible.

The present volume of available secondary treated water within a 15-mile radius of ESGS (680 mgd) can meet the current once-through cooling demand for Units 3 and 4 (380 mgd), although the volume that is reliably available would require pipeline connections to two different sources to ensure an adequate and consistent flow. In lieu of secondary treated water as a replacement for once-through cooling, reclaimed water can be used as makeup water in cooling towers but must meet tertiary treatment and disinfection standards under California Code of Regulations (CCR) Title 22. If the reclaimed water is not treated to the required levels, ESGS would be required to provide sufficient treatment onsite prior to use in the cooling towers. Currently, the West Basin Municipal Water District (WBMWD) treats approximately 30 mgd of secondary water from Hyperion Wastewater Treatment Plant (WWTP) to tertiary standards. This water is used for various projects throughout the South Bay region, such as the seawater barrier conservation project to protect underground aquifers. WBMWD's current available capacity is insufficient to meet the makeup water demand for the wet cooling towers at ESGS (WBMWD 2007).

An additional consideration for the use of reclaimed water is the presence of any ammonia or ammonia-forming compounds in the reclaimed water. All of the condenser tubes at ESGS contain copper alloys (Cu-Ni 90-10) and can experience stress-corrosion cracking as a result of the interaction between copper and ammonia. Treatment for ammonia may include the addition of ferrous sulfate as a corrosion inhibitor or require ammonia-stripping towers to pretreat reclaimed water prior to use in the cooling towers (USEPA 2001).

Two publicly owned treatment works (POTWs) were identified within a 15-mile radius of ESGS, with a combined discharge capacity of 680 mgd. Figure D–6 shows the relative locations of these facilities to ESGS.

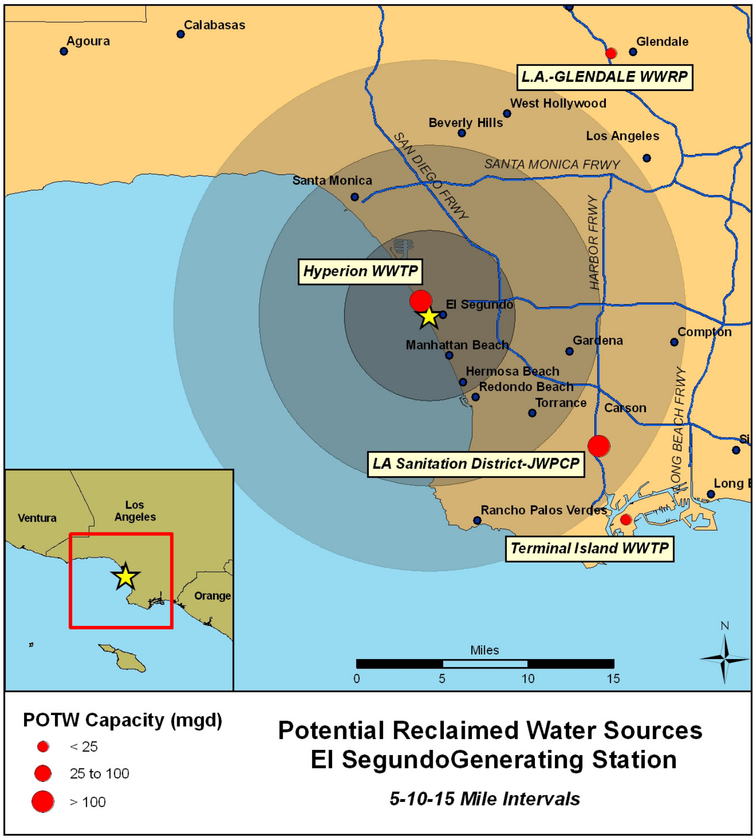

Figure D-6. Reclaimed Water Sources

- *Los Angeles Sanitation District, Hyperion Wastewater Treatment Plant—Los Angeles*
  Discharge volume: 350 mgd
  Distance: 1 mile N
  Treatment level: Secondary

The CEC evaluated the use of secondary treated water from Hyperion as a replacement for once-through cooling in the ESPR FSA in 2002. The assessment determined that the use of Hyperion's water was technically feasible, although the evaluation was based on a once-through demand of 207 mgd that would have been required for the ESPR. Because the distance offshore (2,100 feet) of the ESGS outfall is insufficient to meet water quality standards for public beaches, secondary water used at ESGS would either be returned to Hyperion for discharge through the Hyperion "5 mile" outfall or used for another purpose (CEC 2002a). The final commission decision, however, found that this option was infeasible (CEC 2005).

Any water used in a wet cooling tower at ESGS would have to be treated onsite at the facility. Hyperion does not currently treat to tertiary standards and does not have sufficient area on which to construct a treatment system. WBMWD does not have sufficient excess capacity to meet the demand of a freshwater tower at ESGS (8 to 10 mgd). The 2002 FSA deemed tertiary treatment at ESGS infeasible due to overall size of a treatment facility and the lack of sufficient space at the site (CEC 2002a).

- *Los Angeles Sanitation District, Joint Water Pollution Control Plant (JWPCP)—Carso*n
  Discharge volume: 330 mgd
  Distance: 12 miles SE
  Treatment level: Secondary

  The facility representative at JWPCP indicated that the effluent is not currently considered a potential source of reclaimed water for irrigation due to high TDS concentrations (brine from the Hyperion WWTP is treated at Carson), but the suitability for use as a makeup water source is not currently known. TDS levels may be less than normally found in seawater and thus may be at least comparable to the current makeup water source at ESGS. In the future, a portion of the effluent may be used for a new hydrogen plant under consideration by BP (formerly British Petroleum), but no formal agreement currently exists. Even with such an agreement, sufficient capacity would remain to satisfy the full makeup water demand for freshwater towers at ESGS (8 to 10 mgd).

The costs associated with installing transmission pipelines (excavation/drilling, material, labor), in addition to design and permitting costs, are difficult to quantify in the absence of a detailed analysis of various site-specific parameters that will influence the final configuration. The nearest facility with sufficient capacity to satisfy ESGS's makeup demand (8 to 10 mgd as a freshwater tower) is located approximately 1 mile from the site (Hyperion). Based on data compiled for this study and others, the estimated installed cost of a 24-inch prestressed concrete cylinder pipe, sufficient to provide 10 mgd to ESGS, is $300 per linear foot, or approximately $1.6 million per mile. Additional considerations, such as pump capacity and any required treatment, would increase the total cost.

Regulatory concerns beyond the scope of this investigation may make the use of reclaimed water comparable or preferable to the use of saltwater from marine sources as makeup water. Use of freshwater may reduce or eliminate drift deposition and its associated impacts on sensitive equipment. Reclaimed water may enable ESGS to reduce PM_{10} emissions from the cooling tower, which is a concern given the current nonattainment status of the South Coast air basin, or eliminate potential conflicts with water discharge limitations. ESGS might realize other benefits by using reclaimed water in the form of reduced O&M costs. At any facility where wet cooling towers are a feasible alternative, reclaimed water may be used as a makeup water source; the practicality of its use, however, is a question of the overall cost, availability, and additional environmental benefit that may be realized.

3.4.5 THERMAL EFFICIENCY

The use of wet cooling towers at ESGS will increase the temperature of the condenser inlet water by a range of 9 to 13° F above the surface water temperature, depending on the ambient wet bulb temperature at the time. The generating units at ESGS are designed to operate at the conditions described in Table D–12. The resulting monthly difference between once-through and wet cooling tower condenser inlet temperatures at ESGS is described in Figure D–7.

Table D–12. Design Thermal Conditions

	Unit 3	Unit 4
Design backpressure (in. HgA)	1.6	1.56
Design water temperature (°F)	63	63
Turbine inlet temp (°F)	1,000	1,000
Turbine inlet pressure (psia)	2,400	2,400
Operating heat rate (BTU/kWh) [a]	9,557	9,713

[a] CEC 2002b.

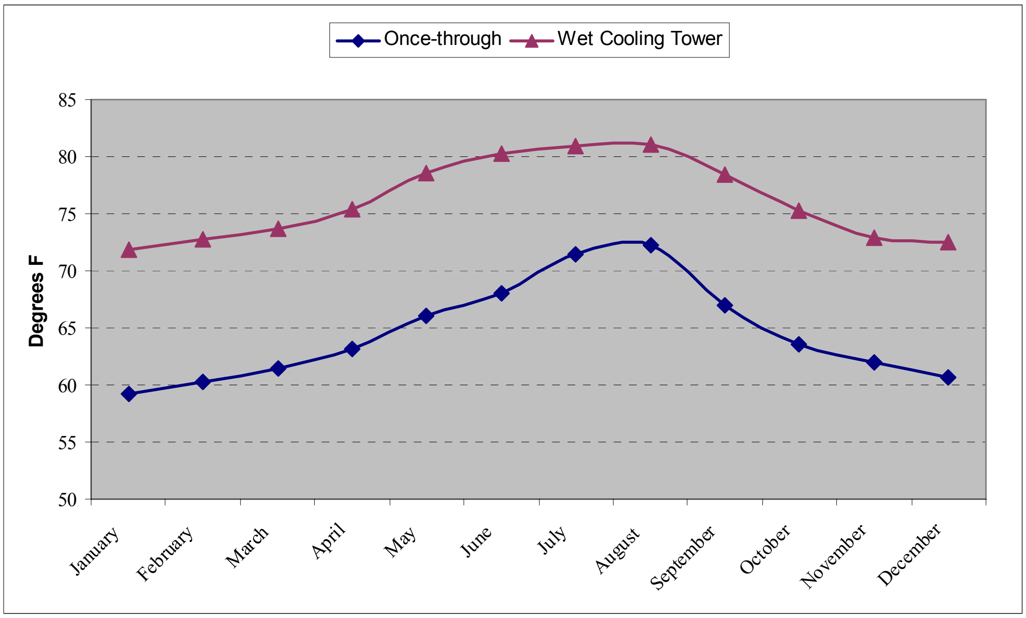

Figure D–7. Condenser Inlet Temperatures

Backpressures for the once-through and wet cooling tower configurations were calculated using the design criteria described in the sections above on a monthly basis using ambient climate data (Table D–6). In general, backpressures associated with the wet cooling tower were elevated by 0.5 to 0.75 inches HgA compared with the current once-through system (Figure D–8 and Figure D–10).

Heat rate adjustments were calculated by comparing the theoretical change in available energy that occurs at different turbine exhaust backpressures, assuming the thermal load and turbine inlet pressure remain constant, i.e., at the maximum load rating.[6] The relative change at different backpressures was compared with the value calculated for the design conditions (i.e., at design

[6] Changes in thermal efficiency estimated for ESGS are based on the design specifications provided by the facility. This may not reflect system modifications that influence actual performance. In addition, the age of the units and the operating protocols used by ESGS may result in different conclusions.

turbine inlet and exhaust backpressures) and plotted as a percentage of the maximum operating heat rate to develop estimated correction curves (Figure D–9 and Figure D–11). A comparison was then made between the relative heat rates of the once-through and wet cooling systems for a given month. The difference between these two values represents the net increase in heat rate that would be expected in a converted system.

Table D–13 summarizes the annual average heat rate increase for each unit as well as the increase associated with the peak demand period of July-August-September. Monthly values were used to develop an estimate of the monetized value of these heat rate changes (Section 4.6). Month-by-month calculations are presented in Appendix A.

Table D–13. Summary of Estimated Heat Rate Increases

	Unit 3	Unit 4
Peak (July-August-September)	1.08%	1.09%
Annual average	1.01%	1.03%

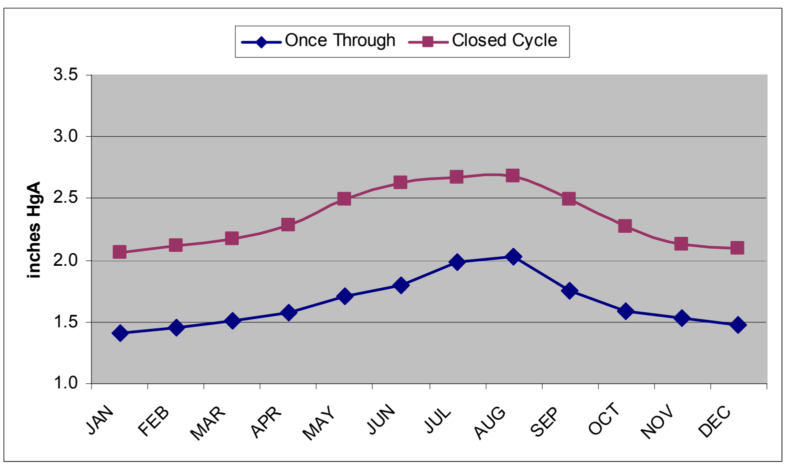

Figure D–8. Estimated Backpressures (Unit 3)

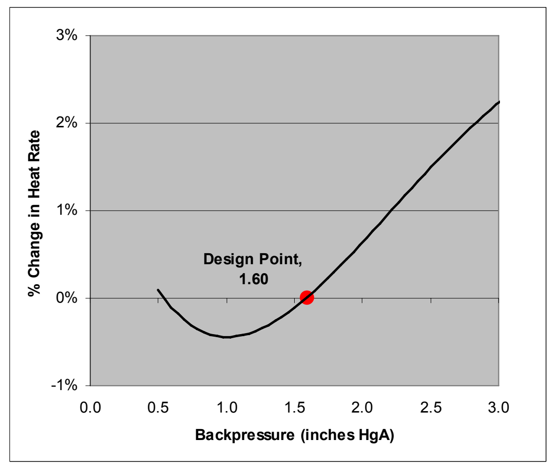

Figure D–9. Estimated Heat Rate Correction (Unit 3)

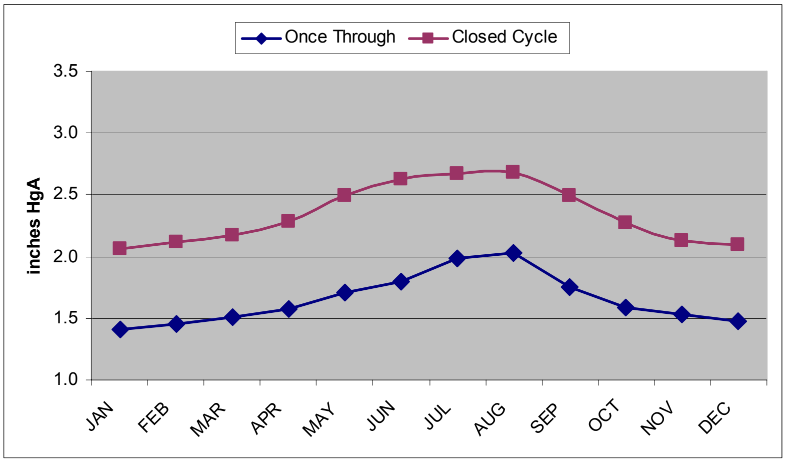

Figure D–10. Estimated Backpressures (Unit 4)

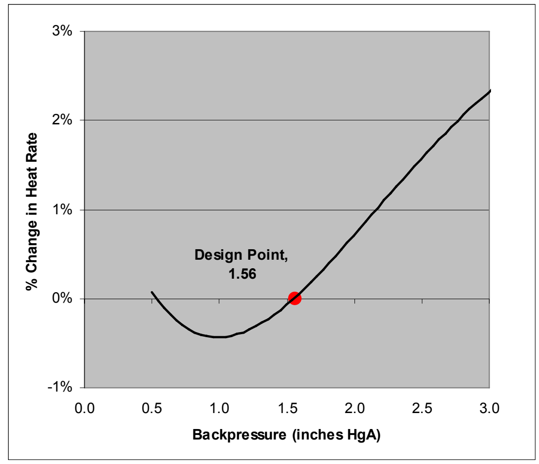

Figure D–11. Estimated Heat Rate Correction (Unit 4)

4.0 RETROFIT COST ANALYSIS

The wet cooling system retrofit estimate for ESGS is based on incorporating conventional wet cooling towers as a replacement for the existing once-through systems for each unit. Standard cost elements for this project include the following:

- Direct (cooling tower installation, civil/structural, mechanical, piping, electrical, and demolition)
- Indirect (smaller project costs not itemized)
- Contingency (allowance for unknown project variables)
- Operations and maintenance (non–energy related cooling tower operations)
- Energy penalty (includes increased parasitic use from fans and pumps as well as decreased thermal efficiency)
- Revenue loss from shutdown (net loss in revenue during construction phase)

The cost analysis does not include allowances for elements that are not quantified in this study, such as land acquisition, effluent treatment, or air emission reduction credits. The methodology used to develop cost estimates is discussed in Chapter 5.

4.1 COOLING TOWER INSTALLATION

In general, the cooling tower configuration selected for ESGS conforms to a typical design; no significant variations from a conventional arrangement were needed, although the preferred configuration (plume-abated towers) was infeasible and not evaluated. Table D–14 summarizes the design-and-build cost estimate for each tower developed by vendors, inclusive of all labor and management required for their installation.

Table D–14. Wet Cooling Tower Design-and-Build Cost Estimate

	Unit 3	Unit 4	ESGS Total
Number of cells	10	10	**20**
Cost/cell ($)	630,000	630,000	**630,000**
Total ESGS D&B cost ($)	**6,300,000**	**6,300,000**	**12,600,000**

4.2 OTHER DIRECT COSTS

A significant portion of the cost incurred for the wet cooling tower installation results from the various support structures and materials (pipes, pumps, etc.), as well the necessary equipment and labor required to prepare the cooling tower site and connect the towers to the cooling system. At ESGS, these costs comprise approximately 45 percent of the initial capital cost. Line item costs are detailed in Appendix B.

Deviations from or additions to the general cost elements discussed in Chapter 3 are discussed below. Other direct costs (non–cooling tower) are summarized in Table D–15.

- *Civil, Structural, and Piping*
  The configuration of the ESGS site allows each tower to be located within relative proximity to the respective generating unit.
- *Mechanical and Electrical*
  Initial capital costs in this category reflect incorporating new pumps (four total) to circulate cooling water between the towers and condensers. No new pumps are required to provide makeup water from the Pacific Ocean. Electrical costs are based on the battery limit after the main feeder breakers.
- *Demolition*
  Costs for the demolition and backfilling of the retention basin are included.

Table D–15. Summary of Other Direct Costs

	Equipment ($)	Bulk material ($)	Labor ($)	ESGS total ($)
Civil/structural/piping	4,700,000	10,200,000	9,000,000	**23,900,000**
Mechanical	5,200,000	0	500,000	**5,700,000**
Electrical	1,300,000	2,000,000	1,500,000	**4,800,000**
Demolition	0	500,000	400,000	**900,000**
Total ESGS other direct costs	**11,200,000**	**12,700,000**	**11,400,000**	**35,300,000**

4.3 INDIRECT AND CONTINGENCY

Indirect costs are calculated as 25 percent of all direct costs (civil/structural, mechanical, electrical, demolition, and cooling towers). An additional allowance is included for reinforcement of the condenser to withstand the increased pressures resulting from incorporation of wet cooling towers. Each condenser may require reinforcement of the tube sheet bracing with 6-inch x 1-inch steel, and water box reinforcement/replacement with 5/8-inch carbon steel. Based on the estimates outlined in Chapter 3, a conservative estimate of 5 percent of all direct costs is included to account for possible condenser modifications.

The contingency cost is calculated as 25 percent of the sum of all direct and indirect costs, including condenser reinforcement. At ESGS, potential costs in this category include relocation or demolition of small buildings and structures and the potential interference with underground structures. Modifications or upgrades to sensitive equipment may be necessary to counteract drift deposition. Soils were not characterized for this analysis. ESGS is situated at 20 feet above sea level adjacent to the Pacific Ocean. Seawater intrusion or the instability of sandy soils may require additional pilings to support any large structures built at the site. Initial capital costs are summarized in Table D–16.

Table D–16. Summary of Initial Capital Costs

	Cost ($)
Cooling towers	12,600,000
Civil/structural/piping	23,900,000
Mechanical	5,700,000
Electrical	4,800,000
Demolition	900,000
Indirect cost	12,000,000
Condenser modification	2,400,000
Contingency	15,600,000
Total ESGS capital cost	**77,900,000**

4.4 SHUTDOWN

A portion of the work relating to installing wet cooling towers can be completed without significant disruption to the operations of ESGS. Units will be offline depending on the length of time it takes to integrate the new cooling system and conduct acceptance testing. For ESGS, a conservative estimate of 4 weeks per unit was developed. Based on 2006 generating output, however, no shutdown is forecast for either unit. Therefore, the cost analysis for ESGS does not include any loss of revenue associated with shutdown at ESGS.

This analysis did not consider shutdown with respect to the required availability of a particular generating unit, nor can it automatically be assumed that the generating profile for 2006 will be the same in each subsequent year. Net output data from 2006 may not reflect any contractual obligations that mandate a particular unit's availability during a given time period.

4.5 OPERATIONS AND MAINTENANCE

Operations and maintenance (O&M) costs for a wet cooling tower system at ESGS include routine maintenance activities; chemicals and treatment systems to control fouling and corrosion in the towers; management and labor; and an allowance for spare parts and replacement. Annual costs are calculated based on the circulating water flow capacity of the towers using a base cost of $4.00/gpm in Year 1 and $5.80/gpm in Year 12, with an annual escalator of 2 percent (USEPA 2001). Year 12 costs increase based on the assumption that maintenance needs, particularly for spare parts and replacements, will be greater for years 12–20. Annual O&M costs, based on the design circulating water flow for the two cooling towers at ESGS (263,800 gpm), are presented in Table D–17. These costs reflect maximum operation.

Table D–17. Annual O&M Costs (Full Load)

	Year 1 ($)	Year 12 ($)
Management/labor	263,400	381,930
Service/parts	421,440	611,088
Fouling	368,760	534,702
Total ESGS O&M cost	**1,053,600**	**1,527,720**

4.6 ENERGY PENALTY

The energy penalty is divided into two components: increased parasitic use resulting from the additional electrical demand of cooling tower fans and pumps; and the decrease in thermal efficiency resulting from elevated turbine backpressure values. Monetizing the energy penalty at ESGS requires some assumption as to how the facility will choose to alter its operations to compensate for these changes, if at all. One option would be to accept the reduced amount of revenue-generating electricity available and absorb the economic loss ("production loss option"). A second option would be to increase the firing rate to the turbine (i.e., consume more fuel) and produce the same amount of revenue-generating electricity as had been obtained with the once-through cooling system ("increased fuel option"). A more likely option, however, is some combination of the two.

Ultimately, the manner in which ESGS would alter operations to address efficiency changes is driven by considerations unknown to this study (e.g., corporate strategy, contractual obligations, operating protocols and turbine pressure tolerances). In all summary cost estimates, this study calculates the energy penalty's monetized value by assuming the facility will use the increased fuel option to compensate for reduced efficiency and generate the amount of electricity equivalent to the once-through system. With this option, the energy penalty is equivalent to the financial cost of additional fuel and is nominally less costly than the production loss option. This option, however, may not reflect long-term costs such as increased maintenance or system degradation that may result from continued operation at a higher-than-designed turbine firing rate. [7]

The energy penalty for ESGS is calculated by first estimating the increased parasitic demand from the cooling tower pumps and fans, expressed as a percentage of the rated capacity of the particular unit(s). Likewise, the change in the unit's heat rate is also expressed as a capacity percentage.

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[7] Increasing the thermal load to the turbine will raise the circulating water temperature exiting the condenser. The cooling towers selected for this study are designed with a maximum water return temperature of approximately 120º F. Depending on each unit's operating conditions (i.e., condenser outlet temperature), the degree to which the thermal input to the turbine can be increased may be limited.

4.6.1 INCREASED PARASITIC USE (FANS AND PUMPS)

Depending on ambient conditions or the operating load at a given time, ESGS may be able to take one or more cooling tower cells offline and still obtain the required level of cooling. This would also reduce the cumulative electrical demand from the fans. For the purposes of this study, however, operations are evaluated at the design conditions, i.e., maximum load; no allowance is made for seasonal changes. The increased electrical demand associated with operation of the cooling tower fans is summarized in Table D–18.

Table D–18. Cooling Tower Fan Parasitic Use

	Tower 1	Tower 2	ESGS total
Units served	Unit 3	Unit 4	--
Generating capacity (MW)	335	335	**670**
Number of fans (one per cell)	10	10	**20**
Motor power per fan (hp)	211	211	--
Total motor power (hp)	2,105	2,105	**4,210**
MW total	1.57	1.57	**3.14**
Fan parasitic use (% of capacity)	**0.47%**	**0.47%**	**0.47%**

The addition of new circulating water pump capacity for the wet cooling towers will also increase the parasitic use of electricity at ESGS. Makeup water will continue to be withdrawn from the Pacific Ocean through the use of one of the existing circulating water pumps; the remaining pumps will be retired. The net increase in pump-related parasitic usage is the difference between the new wet cooling tower configuration (new plus retained pumps) and the existing once-through configuration. Because one of the main design assumptions maintains the existing flow rate through each condenser, the new circulating pumps are single speed and are assumed to operate at their full rated capacity when in use. The increased electrical demand associated with operation of the cooling tower pumps is summarized in Table D–19.

Table D–19. Cooling Tower Pump Parasitic Use

	Tower 1	Tower 2	ESGS total
Units served	Unit 3	Unit 4	--
Generating capacity (MW)	335	335	**670**
Existing pump configuration (hp)	1,156	1,156	**2,312**
New pump configuration (hp)	3,539	3,539	**7,077**
Difference (hp)	2,383	2,383	**4,765**
Difference (MW)	1.8	1.8	**3.6**
Net pump parasitic use (% of capacity)	**0.53%**	**0.53%**	**0.53%**

4.6.2 HEAT RATE CHANGE

Adjustments to the heat rate were calculated based on the ambient conditions for each month and reflect the estimated difference between operations with once-through and wet cooling tower systems. As noted above, the energy penalty analysis assumes ESGS will increase its fuel consumption to compensate for lost efficiency as well as the increased parasitic load from fans and pumps. The higher turbine firing rate will increase the thermal load rejected to the condenser, which, in turn, results in a higher backpressure value and corresponding increase in the heat rate. No data are available describing the changes in turbine backpressures above the design thermal loads. For the purposes of monetizing the energy penalty only, this study conservatively assumed an additional increase in the heat rate of 0.5 percent at the higher firing rate; the actual effect at ESGS may be greater or less. Estimated heat rate changes for each unit at ESGS are presented in Figure D–12 and Figure D–13.

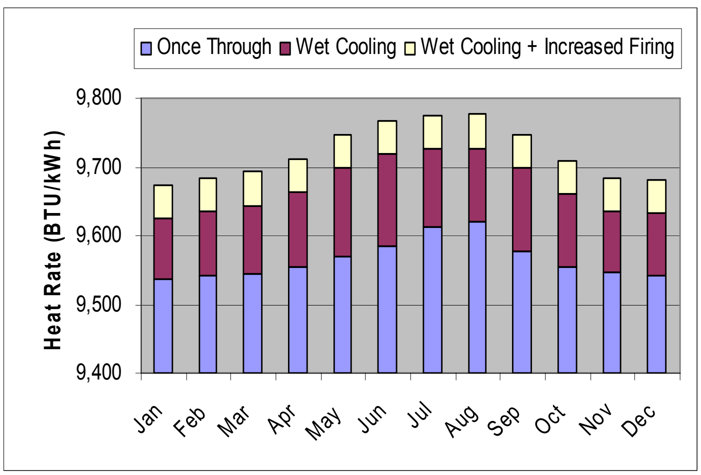

Figure D–12. Estimated Heat Rate Change (Unit 3)

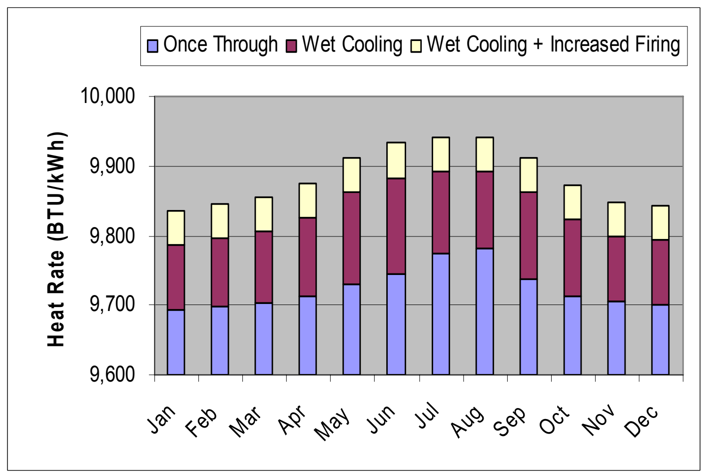

Figure D–13. Estimated Heat Rate Change (Unit 4)

4.6.3 CUMULATIVE ESTIMATE

Using the increased fuel option, the cumulative value of the energy penalty is obtained by first calculating the relative costs of generation ($/MWh) for the once-through and overfired wet cooling systems. The cost of generation for ESGS is based on the relative heat rates developed in Section 4.6.2 and the average monthly wholesale natural gas cost ($/MMBTU) (ICE 2006a). The difference between these two values represents the increased cost, per MWh, that results from incorporating wet cooling towers. The net difference in cost, per month, is applied to the net MWh generated for the particular month, and summed to determine an annual estimate.

Based on 2006 output data, the Year 1 energy penalty for ESGS will be approximately $517,000. In contrast, the value of the energy penalty using the production loss option would be approximately $900,000. Together, these values represent the range of potential energy penalty costs. Table D–20 and Table D–21 summarize the energy penalty estimates for each unit using the increased fuel option.

Table D–20. Unit 3 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	9,537	57.22	9,664	57.98	0.76	27,273	**20,790**
February	5.50	9,541	52.47	9,674	53.20	0.73	0	**0**
March	4.75	9,545	45.34	9,682	45.99	0.65	31,889	**20,726**
April	4.75	9,553	45.38	9,701	46.08	0.70	47,918	**33,622**
May	4.75	9,570	45.46	9,736	46.25	0.79	43,765	**34,527**
June	5.00	9,584	47.92	9,756	48.78	0.86	61,138	**52,695**
July	6.50	9,613	62.48	9,764	63.47	0.98	59,384	**58,337**
August	6.50	9,620	62.53	9,765	63.47	0.94	28,763	**26,996**
September	4.75	9,577	45.49	9,735	46.24	0.75	26,782	**20,162**
October	5.00	9,555	47.78	9,699	48.49	0.72	0	**0**
November	6.00	9,548	57.29	9,675	58.05	0.76	12,603	**9,605**
December	6.50	9,542	62.02	9,670	62.86	0.83	0	**0**
							Unit 3 total	**277,460**

Table D–21. Unit 4 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	9,694	58.17	9,826	58.96	0.79	22,684	**17,959**
February	5.50	9,699	53.34	9,836	54.10	0.76	15,641	**11,842**
March	4.75	9,704	46.09	9,845	46.77	0.67	16,780	**11,282**
April	4.75	9,712	46.13	9,865	46.86	0.72	25,268	**18,289**
May	4.75	9,730	46.22	9,900	47.03	0.81	23,398	**18,956**
June	5.00	9,745	48.72	9,921	49.61	0.88	40,497	**35,746**
July	6.50	9,775	63.53	9,929	64.54	1.00	73,178	**73,411**
August	6.50	9,782	63.58	9,930	64.54	0.96	35,269	**33,783**
September	4.75	9,737	46.25	9,899	47.02	0.77	25,027	**19,329**
October	5.00	9,714	48.57	9,862	49.31	0.74	0	**0**
November	6.00	9,706	58.24	9,837	59.02	0.79	0	**0**
December	6.50	9,700	63.05	9,833	63.91	0.86	0	**0**
							Unit 4 total	**240,597**

4.7 NET PRESENT COST

The Net Present Cost (NPC) of a wet cooling system retrofit at ESGS is the sum of all annual expenditures over the 20-year life span of the project and discounted according to the year in which the expense is incurred and the selected discount rate. The NPC_{20} represents the total change in revenue streams, in 2007 dollars, that ESGS can expect over 20 years as a direct result of converting to wet cooling towers. The following values were used to calculate the NPC at a 7 percent discount rate:

- *Capital and Start-up.* Includes all capital, indirect, contingency, and shutdown costs. All costs in this category are incurred in Year 0. (See Table D–16.)
- *Annual O&M.* Base cost values for Year 1 and Year 12 are adjusted for subsequent years using a 2 percent year-over-year escalator. Because ESGS has a relatively low capacity utilization factor, O&M costs for the NPC calculation were estimated at 30 percent of their maximum value. (See Table D–17.)
- *Annual Energy Penalty.* Insufficient information is available to this study to forecast future generating capacity at ESGS. In lieu of annual estimates, this study uses the net MWh output from 2006 as the basis for estimating the energy penalty value for Years 1 through 20, including a year-over-year wholesale price escalation of 5.8 percent (based on the Producer Price Index). The energy penalty value is based on the increased fuel option discussed in Section 4.6. (See Table D–20 and Table D–21.)

Using these values, the NPC_{20} for ESGS is \$91 million. Appendix C contains detailed annual calculations used to develop this cost.

4.8 ANNUAL COST

The annual cost incurred by ESGS for the retrofit of the once-through cooling system is the sum of the annual amortized capital cost plus the 20-year annual average of O&M and energy penalty expenditures. Capital costs are amortized at a 7 percent discount rate over 20 years. O&M and energy penalty costs are calculated in the same manner as for the NPC_{20} (Section 4.7). The annual cost does not include any loss of revenue associated with shutdown, if any. This loss would be incurred in Year 0 only.

Table D–22. Annual Cost

Discount rate (%)	Capital (\$)	Annual O&M (\$)	Annual energy penalty (\$)	Annual cost (\$)
7	7,400,000	400,000	900,000	**8,700,000**

4.9 COST-TO-GROSS REVENUE COMPARISON

Limited financial data are available to conduct a detailed analysis of the economic impact that a wet cooling system retrofit will have on annual revenues for ESGS. An approximation of the gross annual revenue can be made using 2006 net generating data (CEC 2006) and average wholesale prices for electricity as recorded at the SP 15 trading hub (ICE 2006b). This estimate, therefore, does not reflect any changes that may result from different wholesale prices or contract agreements that may increase or decrease the gross revenue summarized below, nor does it account for liabilities such as taxes or other operational costs.

The estimate of gross annual revenue from electricity sales at ESGS is a straightforward calculation that multiplies the monthly wholesale cost of electricity by the amount generated for the particular month. The estimated gross revenue for ESGS is summarized in Table D–23. A comparison of annual costs to annual gross revenue is summarized in Table D–24.

Table D‒23. Estimated Gross Revenue

	Wholesale price ($/MWh)	Net generation (MWh)		Estimated gross revenue ($2007)		
		Unit 1	Unit 2	Unit 1	Unit 2	ESGS total
January	66	27,273	22,684	1,800,018	1,497,144	**3,297,162**
February	61	0	15,641	0	954,101	**954,101**
March	51	31,889	16,780	1,626,339	855,780	**2,482,119**
April	51	47,918	25,268	2,443,818	1,288,668	**3,732,486**
May	51	43,765	23,398	2,232,015	1,193,298	**3,425,313**
June	55	61,138	40,497	3,362,590	2,227,335	**5,589,925**
July	91	59,384	73,178	5,403,944	6,659,198	**12,063,142**
August	73	28,763	35,269	2,099,699	2,574,637	**4,674,336**
September	53	26,782	25,027	1,419,446	1,326,431	**2,745,877**
October	57	0	0	0	0	**0**
November	66	12,603	0	831,798	0	**831,798**
December	67	0	0	0	0	**0**
ESGS total		**339,515**	**277,742**	**21,219,667**	**18,576,592**	**39,796,259**

Table D‒24. Cost-Revenue Comparison

Estimated gross annual revenue ($)	Initial capital		O&M		Energy penalty		Total annual cost	
	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross
39,800,000	7,400,000	19.0	400,000	1.0	900,000	2.3	**8,700,000**	**22**

5.0 OTHER TECHNOLOGIES

Within the scope of this study, and using the OPC resolution's stated goal of reducing impingement and entrainment by 90–95 percent as a benchmark, the effectiveness of other technologies commonly used to address such impacts could not be conclusively determined for use at ESGS. As with many existing facilities, the location and configuration of the site complicates the use of some technologies that might be used successfully elsewhere. A more detailed analysis that also comprises a biological evaluation may determine the applicability of one or more of these technologies to ESGS. A brief summary of the applicability of these technologies follows.

5.1 MODIFIED RISTROPH SCREENS—FINE MESH

The principal concern with this technology is the successful return of viable organisms captured on the screens to the source water body. ESGS currently withdraws its cooling water through a submerged conduit extending approximately 2,000 feet offshore at a depth of 20 feet. Returning any collected organisms to a similar location would be impractical. It is unclear whether organisms could be returned to a near-shore location closer to the facility and remain viable.

5.2 BARRIER NETS

Barrier nets are unproven in an open ocean environment.

5.3 AQUATIC FILTRATION BARRIERS

Aquatic filtration barriers (AFBs) are unproven in an open-ocean environment.

5.4 VARIABLE SPEED DRIVES

Variable speed drives (VSDs) were not considered for analysis at ESGS because the technology alone cannot be expected to achieve the desired level of reductions in impingement and entrainment, nor could it be combined with another technology to yield the desired reductions. Pumps that have been retrofitted with VSDs can reduce overall flow intake volumes by 10 to 50 percent over the current once-through configuration (USEPA 2001). The actual reduction, however, will vary based on the cooling water demand at different times of the year. At peak demand, the pumps will essentially function as standard circulating water pumps and withdraw water at the maximum rated capacity, thus negating any potential benefit. Use of VSDs may be an economically desirable option when pumps are retrofitted or replaced for other reasons, but VSDs were not considered further for this study.

5.5 CYLINDRICAL FINE-MESH WEDGEWIRE

Fine-mesh cylindrical wedgewire screens have not been deployed or evaluated at open coastal facilities for applications as large as would be required at ESGS (approximately 380 mgd). To function as intended, cylindrical wedgewire screens must be submerged in a water body with a consistent ambient current of 0.5 fps. Ideally, this current would be unidirectional so that screens may be oriented properly and any debris impinged on the screens will be carried downstream when the airburst cleaning system is activated.

Fine-mesh wedgewire screens for ESGS would be located offshore in the Pacific Ocean, west of the facility. Limited information regarding the subsurface currents in the near-shore environment near ESGS is available. Data suggest that these currents are multidirectional depending on the tide and season and fluctuate in terms of velocity, with prolonged periods below 0.5 fps (SCCOOS 2006). To attain sufficient depth (approximately 20 feet) and an ambient current that might allow deployment, screens would need to be located 2,000 feet or more offshore. Discussions with vendors who design these systems indicated that distances more than 1,000 to 1,500 feet become problematic due to the inability of the airburst system to maintain adequate pressure for sufficient cleaning (Someah 2007). Together, these considerations preclude further evaluation of fine-mesh cylindrical wedgewire screens at ESGS.

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Appendix A. Once-Through and Closed-Cycle Thermal Performance

		Unit 3			Unit 4		
		Once through	Closed cycle	Net increase	Once through	Closed cycle	Net increase
JAN	Backpressure (in. HgA)	1.41	2.06	**0.64**	1.40	2.04	**0.64**
	Heat rate Δ (%)	*-0.21*	*0.71*	***0.93***	*-0.19*	*0.76*	***0.96***
FEB	Backpressure (in. HgA)	1.46	2.12	**0.66**	1.44	2.10	**0.66**
	Heat rate Δ (%)	*-0.17*	*0.82*	***0.99***	*-0.15*	*0.87*	***1.02***
MAR	Backpressure (in. HgA)	1.50	2.17	**0.66**	1.49	2.15	**0.66**
	Heat rate Δ (%)	*-0.12*	*0.91*	***1.03***	*-0.10*	*0.97*	***1.06***
APR	Backpressure (in. HgA)	1.57	2.28	**0.71**	1.56	2.26	**0.70**
	Heat rate Δ (%)	*-0.04*	*1.11*	***1.15***	*-0.01*	*1.17*	***1.18***
MAY	Backpressure (in. HgA)	1.70	2.49	**0.79**	1.69	2.47	**0.79**
	Heat rate Δ (%)	*0.13*	*1.48*	***1.35***	*0.17*	*1.54*	***1.37***
JUN	Backpressure (in. HgA)	1.80	2.62	**0.82**	1.78	2.60	**0.82**
	Heat rate Δ (%)	*0.28*	*1.70*	***1.42***	*0.32*	*1.75*	***1.43***
JUL	Backpressure (in. HgA)	1.98	2.67	**0.69**	1.97	2.65	**0.69**
	Heat rate Δ (%)	*0.59*	*1.78*	***1.19***	*0.63*	*1.83*	***1.20***
AUG	Backpressure (in. HgA)	2.03	2.68	**0.65**	2.01	2.66	**0.65**
	Heat rate Δ (%)	*0.66*	*1.79*	***1.12***	*0.71*	*1.84*	***1.13***
SEP	Backpressure (in. HgA)	1.75	2.49	**0.74**	1.73	2.47	**0.73**
	Heat rate Δ (%)	*0.21*	*1.48*	***1.27***	*0.25*	*1.53*	***1.29***
OCT	Backpressure (in. HgA)	1.59	2.27	**0.68**	1.57	2.25	**0.68**
	Heat rate Δ (%)	*-0.02*	*1.09*	***1.11***	*0.01*	*1.14*	***1.13***
NOV	Backpressure (in. HgA)	1.53	2.12	**0.60**	1.51	2.10	**0.60**
	Heat rate Δ (%)	*-0.10*	*0.83*	***0.93***	*-0.07*	*0.88*	***0.95***
DEC	Backpressure (in. HgA)	1.47	2.10	**0.62**	1.46	2.08	**0.62**
	Heat rate Δ (%)	*-0.15*	*0.78*	***0.94***	*-0.13*	*0.84*	***0.97***

Note: Heat rate delta represents change from design value calculated according to estimated ambient conditions for each month.

Appendix B. Itemized Capital Costs

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
CIVIL / STRUCTURAL / PIPING	--	--	--	--	--	--	--	--	--	--
Allocation for other accessories (bends, water hammers…)	lot	1	--	--	500,000	500,000	4,000.00	85	340,000	**840,000**
Allocation for pipe racks (approx 800 ft) and cable racks	t	80	--	--	2,500	200,000	17.00	105	142,800	**342,800**
Allocation for sheet piling and dewatering	lot	1	--	--	500,000	500,000	5,000.00	100	500,000	**1,000,000**
Allocation for testing pipes	lot	1	--	--	--	--	2,000.00	95	190,000	**190,000**
Allocation for Tie-Ins to existing condenser's piping	lot	1	--	--	250,000	250,000	2,000.00	85	170,000	**420,000**
Allocation for trust blocks	lot	1	--	--	50,000	50,000	500.00	95	47,500	**97,500**
Backfill for PCCP pipe (reusing excavated material)	m3	9,281	--	--	--	--	0.04	200	74,248	**74,248**
Bedding for PCCP pipe	m3	1,478	--	--	25	36,950	0.04	200	11,824	**48,774**
Bend for PCCP pipe 24" diam (allocation)	ea	12	--	--	3,000	36,000	20.00	95	22,800	**58,800**
Bend for PCCP pipe 30" & 36" diam (allocation)	ea	18	--	--	5,000	90,000	25.00	95	42,750	**132,750**
Bend for PCCP pipe 72" diam (allocation)	ea	12	--	--	18,000	216,000	40.00	95	45,600	**261,600**
Bend for PCCP pipe 84" diam (allocation)	ea	8	--	--	20,000	160,000	50.00	95	38,000	**198,000**
Building architectural (siding, roofing, doors, painting…etc)	ea	2	--	--	250,000	500,000	3,000.00	75	450,000	**950,000**
Butterfly valves 30" c/w allocation for actuator & air lines	ea	28	30,800	862,400	--	--	50.00	85	119,000	**981,400**
Butterfly valves 60" c/w allocation for actuator & air lines	ea	8	75,600	604,800	--	--	60.00	85	40,800	**645,600**
Butterfly valves 72" c/w allocation for actuator & air lines	ea	12	96,600	1,159,200	--	--	75.00	85	76,500	**1,235,700**
Butterfly valves 84" c/w allocation for actuator & air lines	ea	12	124,600	1,495,200	--	--	75.00	85	76,500	**1,571,700**
Check valves 30"	ea	4	44,000	176,000	--	--	16.00	85	5,440	**181,440**
Check valves 60"	ea	4	108,000	432,000	--	--	30.00	85	10,200	**442,200**
Concrete basin walls (all in)	m3	350	--	--	225	78,750	8.00	75	210,000	**288,750**
Concrete elevated slabs (all in)	m3	646	--	--	250	161,500	10.00	75	484,500	**646,000**
Concrete for transformers and oil catch basin (allocation)	m3	200	--	--	250	50,000	10.00	75	150,000	**200,000**
Concrete slabs on grade (all in)	m3	2,622	--	--	200	524,400	4.00	75	786,600	**1,311,000**
Ductile iron cement pipe 12" diam. for fire water line	ft	800	--	--	100	80,000	0.60	95	45,600	**125,600**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Excavation and backfill for fire line, blowdown & make-up (using excavated material for backfill except for bedding)	m3	4,264	--	--	--	--	0.08	200	68,224	**68,224**
Excavation for PCCP pipe	m3	14,340	--	--	--	--	0.04	200	114,720	**114,720**
Fencing around transformers	m	50	--	--	30	1,500	1.00	75	3,750	**5,250**
Flange for PCCP joints 30"	ea	22	--	--	2,260	49,720	16.00	95	33,440	**83,160**
Flange for PCCP joints 72"	ea	8	--	--	9,860	78,880	25.00	95	19,000	**97,880**
Flange for PCCP joints 84"	ea	16	--	--	13,210	211,360	30.00	95	45,600	**256,960**
Foundations for pipe racks and cable racks	m3	190	--	--	250	47,500	8.00	75	114,000	**161,500**
FRP flange 30"	ea	82	--	--	1,679	137,690	50.00	85	348,500	**486,190**
FRP flange 60'	ea	12	--	--	7,785	93,424	100.00	85	102,000	**195,424**
FRP flange 72"	ea	20	--	--	20,888	417,754	200.00	85	340,000	**757,754**
FRP flange 84"	ea	8	--	--	33,381	267,048	300.00	85	204,000	**471,048**
FRP pipe 60" diam.	ft	200	--	--	615	122,980	0.90	85	15,300	**138,280**
FRP pipe 84" diam.	ft	1,800	--	--	946	1,702,800	1.50	85	229,500	**1,932,300**
Harness clamp 24" c/w external testable joint	ea	20	--	--	1,715	34,300	14.00	95	26,600	**60,900**
Harness clamp 30" & 36"c/w internal testable joint	ea	40	--	--	2,000	80,000	16.00	95	60,800	**140,800**
Harness clamp 72" c/w internal testable joint	ea	80	--	--	2,440	195,200	18.00	95	136,800	**332,000**
Harness clamp 84" c/w internal testable joint	ea	70	--	--	2,845	199,150	20.00	95	133,000	**332,150**
Joint for FRP pipe 84" diam.	ea	60	--	--	5,014	300,828	300.00	85	1,530,000	**1,830,828**
Joint for FRP pipe 60" diam.	ea	10	--	--	1,797	17,974	100.00	85	85,000	**102,974**
PCCP pipe 24" dia. For blowdown	ft	400	--	--	98	39,200	0.50	95	19,000	**58,200**
PCCP pipe 30" dia. for make-up	ft	700	--	--	125	87,500	0.70	95	46,550	**134,050**
PCCP pipe 72" diam.	ft	1,600	--	--	507	811,200	1.30	95	197,600	**1,008,800**
PCCP pipe 84" diam.	ft	1,400	--	--	562	786,800	1.50	95	199,500	**986,300**
Riser (FRP pipe 30" diam X55 ft)	ea	20	--	--	15,350	306,996	150.00	85	255,000	**561,996**
Structural steel for building	t	315	--	--	2,500	787,500	20.00	105	661,500	**1,449,000**
CIVIL / STRUCTURAL / PIPING TOTAL	**--**	**--**	**--**	**4,729,600**	**--**	**10,210,904**	**--**	**--**	**9,070,046**	**24,010,550**
DEMOLITION	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**
Allocation for relocation of pumps, pipes, controls and other associated works	lot	1	--	--	125,000	125,000	1,250.00	100	125,000	**250,000**
Excavation and disposal of non contaminated material for the relocated pond	m3	12,750	--	--	--	--	0.12	100	153,000	**153,000**
Filling existing pond (approx 300 ft X 100 ft X 5m deep assumed) with granular material	m3	12,750	--	--	25	318,747	0.04	100	51,000	**369,746**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Membranes and sand bedding	lot	1	--	--	100,000	100,000	1,000.00	100	100,000	**200,000**
DEMOLITION TOTAL	--	--	--	**0**	--	**543,747**	--	--	**429,000**	**972,746**
ELECTRICAL	--	--	--	--	--	--	--	--	--	--
4.16 kv cabling feeding MCC's	m	1,000	--	--	75	75,000	0.40	85	34,000	**109,000**
4.16kV switchgear - 4 breakers	ea	1	250,000	250,000	--	--	175.00	85	14,875	**264,875**
480 volt cabling feeding MCC's	m	750	--	--	70	52,500	0.40	85	25,500	**78,000**
480V Switchgear - 1 breaker 3000A	ea	4	30,000	120,000	--	--	80.00	85	27,200	**147,200**
Allocation for automation and control	lot	1	--	--	750,000	750,000	7,500.00	85	637,500	**1,387,500**
Allocation for cable trays and duct banks	m	1,300	--	--	75	97,500	1.00	85	110,500	**208,000**
Allocation for lighting and lightning protection	lot	1	--	--	100,000	100,000	1,000.00	85	85,000	**185,000**
Dry Transformer 2MVA xxkV-480V	ea	4	100,000	400,000	--	--	100.00	85	34,000	**434,000**
Lighting & electrical services for pump house building	ea	2	--	--	50,000	100,000	500.00	85	85,000	**185,000**
Local feeder for 200 HP motor 460 V (up to MCC)	ea	20	--	--	15,000	300,000	140.00	85	238,000	**538,000**
Local feeder for 2000 HP motor 4160 V (up to MCC)	ea	4	--	--	40,000	160,000	160.00	85	54,400	**214,400**
Oil Transformer 10/13.3MVA xx-4.16kV	ea	2	190,000	380,000	--	--	150.00	85	25,500	**405,500**
Primary breaker(xxkV)	ea	4	45,000	180,000	--	--	60.00	85	20,400	**200,400**
Primary feed cabling (assumed 13.8 kv)	m	2,000	--	--	175	350,000	0.50	85	85,000	**435,000**
ELECTRICAL TOTAL	--	--	--	**1,330,000**	--	**1,985,000**	--	--	**1,476,875**	**4,791,875**
MECHANICAL	--	--	--	--	--	--	--	--	--	--
Allocation for ventilation of buildings	ea	2	100,000	200,000	--	--	1,000.00	85	170,000	**370,000**
Cooling tower for unit 3	lot	1	6,300,000	6,300,000	--	--	--	--	--	**6,300,000**
Cooling tower for unit 4	lot	1	6,300,000	6,300,000	--	--	--	--	--	**6,300,000**
Overhead crane 50 ton in (in pump house) Including additional structure to reduce the span	ea	2	500,000	1,000,000	--	--	1,000.00	85	170,000	**1,170,000**
Pump 4160 V 2000 HP	ea	4	1,000,000	4,000,000	--	--	500.00	85	170,000	**4,170,000**
MECHANICAL TOTAL	--	--	--	**17,800,000**	--	**0**	--	--	**510,000**	**18,310,000**

Appendix C. Net Present Cost Calculation

Project year	Capital/start-up ($)	O & M ($)	Energy penalty ($)		Total ($)	Annual discount factor	Present value ($)
			Unit 3	Unit 4			
0	78,100,000	--	--	--	78,100,000	1	**78,100,000**
1	--	316,080	297,657	258,182	871,919	0.9346	**814,896**
2	--	322,402	315,011	273,234	910,646	0.8734	**795,358**
3	--	328,850	333,376	289,163	951,389	0.8163	**776,619**
4	--	335,427	352,812	306,022	994,260	0.7629	**758,521**
5	--	342,135	373,380	323,863	1,039,378	0.713	**741,077**
6	--	348,978	395,149	342,744	1,086,870	0.6663	**724,182**
7	--	355,957	418,186	362,726	1,136,869	0.6227	**707,928**
8	--	363,077	442,566	383,873	1,189,515	0.582	**692,298**
9	--	370,338	468,368	406,253	1,244,958	0.5439	**677,133**
10	--	377,745	495,673	429,937	1,303,355	0.5083	**662,495**
11	--	385,300	524,571	455,002	1,364,873	0.4751	**648,451**
12	--	467,482	555,154	481,529	1,504,165	0.444	**667,849**
13	--	476,832	587,519	509,602	1,573,953	0.415	**653,191**
14	--	486,369	621,771	539,312	1,647,452	0.3878	**638,882**
15	--	496,096	658,021	570,754	1,724,871	0.3624	**625,093**
16	--	506,018	696,383	604,029	1,806,430	0.3387	**611,838**
17	--	516,138	736,982	639,244	1,892,364	0.3166	**599,123**
18	--	526,461	779,949	676,512	1,982,921	0.2959	**586,746**
19	--	536,990	825,420	715,952	2,078,362	0.2765	**574,667**
20	--	547,730	873,542	757,692	2,178,964	0.2584	**563,044**
Total							**91,619,391**

E. Harbor Generating Station

Los Angeles Dept. of Water and Power—Los Angeles, CA

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Appendices

1.0 GENERAL SUMMARY

Retrofitting the existing once-through cooling system at Harbor Generating Station (HGS) with a closed-cycle wet cooling tower is technically and logistically feasible based on this study's design criteria, and will reduce cooling water withdrawals from Los Angeles Harbor by approximately 94 percent. Impingement and entrainment impacts would be reduced by a similar proportion.

The preferred option selected for HGS includes one conventional wet cooling tower (without plume abatement), with individual cells arranged in a inline configuration to accommodate limited space at the site. This option assumes the availability of adjoining property currently owned by the City of Long Beach to optimally site the cooling tower. Space limitations would appear to preclude plume-abated towers in the design if they were required to mitigate visual impacts. Initial capital costs for the towers would also increase by a factor of 2 or 3.

Construction-related shutdowns are estimated to take approximately 4 weeks per unit (concurrent), although HGS is not expected to incur any financial loss as a result based on 2006 capacity utilization rates for all units.

The proximity of large wastewater treatment facilities may enable HGS to replace the current once-through cooling water volume (81 mgd) with secondary treated effluent. To do so would require installing transmission pipelines several miles through the heavily developed Wilmington and Los Angeles Harbor areas. Because HGS's current outfall is located near the shoreline, discharge of secondary treated water into the harbor may not be permitted. In this case, HGS would be required to ensure treatment prior to discharge or route effluent to another location.

The cooling tower configuration designed under the preferred option complies with all identified local use restrictions and includes necessary mitigation measures, where applicable.

1.1 COST

As noted above, some questions exist over the availability of sufficient land allowing the optimal cooling tower design and placement. For the purposes of this study, and all costs developed for HGS, it is assumed that this land will be available for use. The analysis does not, however, evaluate the additional costs that may be incurred from purchase or lease of this property.

Initial capital and net present costs associated with installing and operating wet cooling towers at HGS are summarized in Table E–1. Annualized costs based on 20-year average values for the various cost elements are summarized in Table E–2.

Table E–1. Cumulative Cost Summary

Cost Category	Cost ($)	Cost per MWh (rated capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Total capital and start-up [a]	26,000,000	12.63	142
NPC_{20} [b]	28,600,000	13.88	156

[a] Includes all costs associated with the cooling tower construction and installation and shutdown loss, if any.
[b] NPC_{20} includes all capital costs, operation and maintenance costs, and energy penalty costs over 20 years discounted at 7 percent.

Table E–2. Annual Cost Summary

Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Capital and start-up	2,500,000	1.21	13.64
Operations and maintenance	100,000	0.05	0.55
Energy penalty	200,000	0.10	1.09
Total HGS annual cost	**2,800,000**	**1.36**	**15.28**

1.2 ENVIRONMENTAL

Environmental changes associated with a cooling tower retrofit for HGS are summarized in Table E–3 and discussed further in Section 3.4.

Table E–3. Environmental Summary

		Unit 5
Water use	Design intake volume (gpm)	56,400
	Cooling tower makeup water (gpm)	3,200
	Reduction from capacity (%)	94
Energy efficiency [a]	Summer heat rate increase (%)	0.59
	Summer energy penalty (%)	1.25
	Annual heat rate increase (%)	0.48
	Annual energy penalty (%)	1.14
Direct air emissions [b]	PM_{10} emissions (tons/yr) (maximum capacity)	32
	PM_{10} emissions (tons/yr) (2006 capacity utilization)	2.89

[a] Reflects the comparative increase between once-through and wet cooling systems, but does not account for any operational changes to address the change in efficiency, such as increased fuel consumption (see Section 4.6).
[b] Reflects emissions from the cooling tower only; does not include any increase in stack emissions.

1.3 OTHER POTENTIAL FACTORS

Considerations outside this study's scope may limit the practicality or overall feasibility of a wet cooling tower retrofit at Harbor.

Because parts of Los Angeles Harbor have been listed as impaired for some metals, HGS may face wastewater discharge permit conflicts upon converting to wet cooling towers. If makeup water is obtained from the current source, metal concentrations in the discharge will increase from evaporation in the wet cooling tower. Conflicts with effluent limitations may be mitigated or eliminated through the use of reclaimed water as the makeup source.

The only potential challenge to siting a wet cooling tower at HGS appears to be the availability of a small parcel of land immediately adjacent to the HGS property that is currently owned by the city of Long Beach. Securing the use of this parcel, or a portion thereof, enables a more favorable placement of the wet cooling tower with respect to the generating units and other structures at HGS. If this area is unavailable, existing structures at the site would have to be reconfigured to accommodate a cooling tower. This study assumes the availability of obtaining adjacent land for the desired configuration.

2.0 BACKGROUND

HGS is a natural gas–fired steam electric generating facility located in the Wilmington section of the city of Los Angeles, owned and operated by the Los Angeles Department of Water and Power (LADWP). HGS currently operates seven gas combustion turbines and one steam turbine (Unit 5). A heat recovery steam generator (HRSG) captures exhaust heat from Units 1 and 2 to generate steam for Unit 5. The facility's total capacity is 472 MW, with the combined-cycle portion (Units 1, 2, and 5) accounting for 235 MW. Only the steam portion of the combined-cycle system requires cooling water.[1] HGS occupies an area of approximately 20 acres in the Inner Los Angeles Harbor Complex (ILAHC). (See Table E–4 and Figure E–1.)

Table E–4. General Information

Unit	In-service year	Rated capacity (MW)	2006 capacity utilization [a]	Condenser cooling water flow (gpm)
Unit 5	1994	235 [b]	8.9%	56,400
HGS total		**235**	**8.9**	**56,400**

[a] Quarterly Fuel and Energy Report—2006 (CEC 2006).
[b] Includes gas combustion capacity (2 x 80 MW) and steam turbine capacity (75 MW).

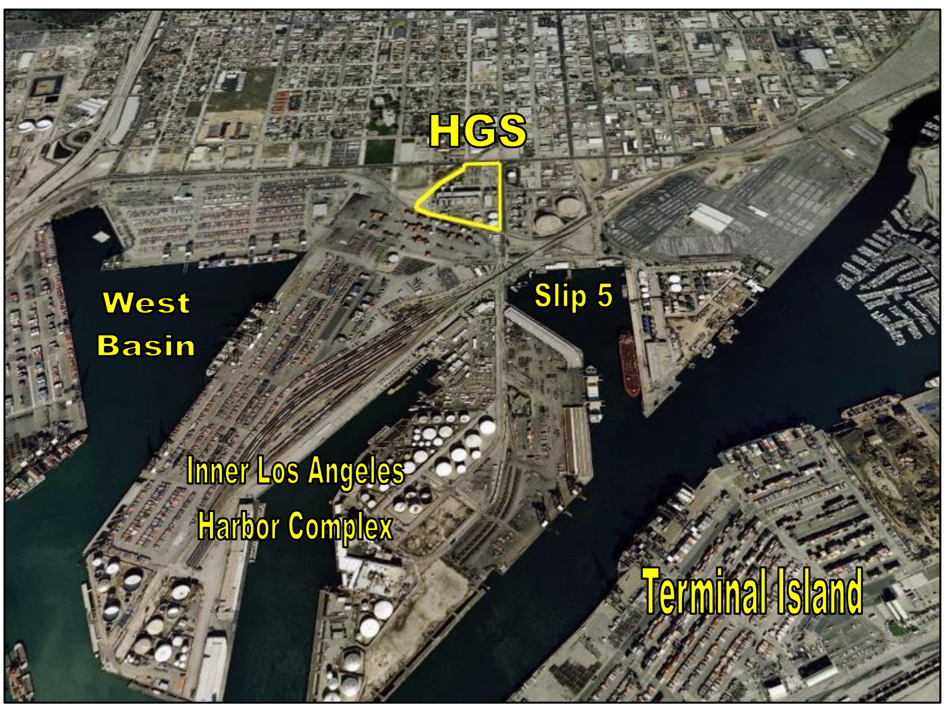

Figure E–1. General Vicinity of Harbor Generating Station

[1] Documents occasionally identify the components of the combined-cycle unit independently: Unit 5 (steam turbine) and Units 1 and 2 (gas turbines). Because the advantage of a combined-cycle system is only obtained when the units function together, reference to "Unit 5" at HGS in this study is taken to mean the combined-cycle unit as a whole.

2.1 COOLING WATER SYSTEM

HGS operates one cooling water intake structure (CWIS) to provide condenser cooling water to the steam portion of the combined-cycle generating unit (Figure E–2). Once-through cooling water is combined with low-volume wastes generated by HGS and discharged through a single outfall to the West Basin of ILAHC. Surface water withdrawals and discharges are regulated by NPDES Permit CA0000361 as implemented by Los Angeles Regional Water Quality Control Board (LARWQCB) Order R4-2003-0101.

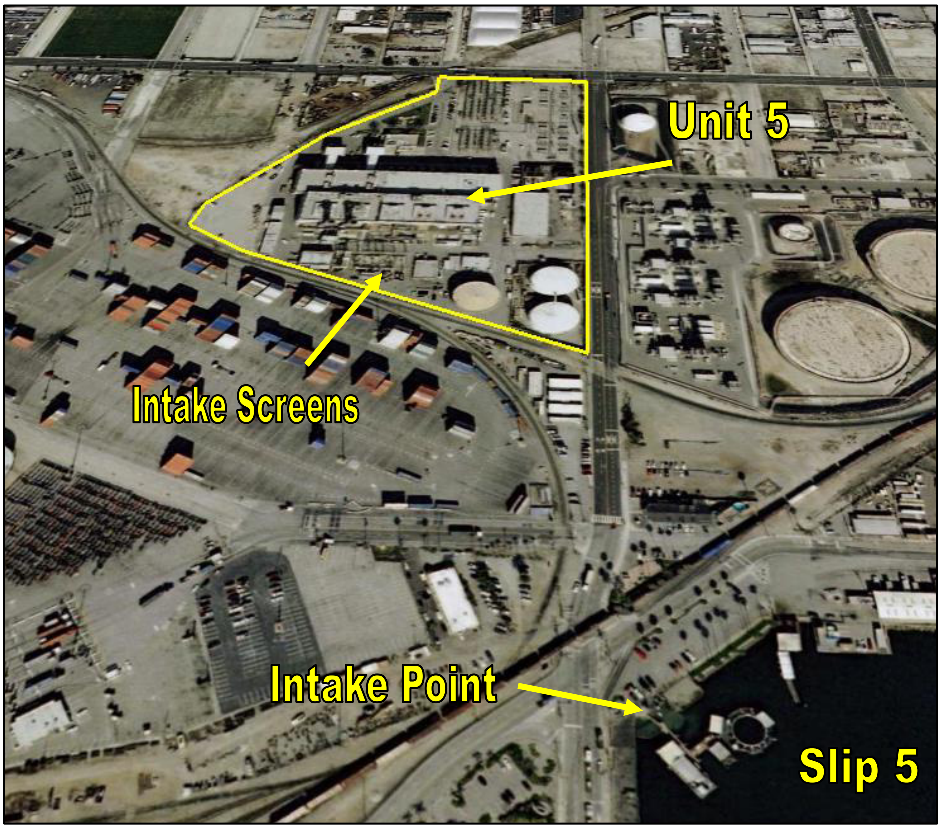

Figure E–2. Site View

Cooling water is obtained from ILAHC through a surface intake located at the shoreline in the northwest corner of Slip 5. Water is transferred to the station through two underground pipes, each approximately 1,100 feet long and 8 feet in diameter. The screenhouse near the station contains six intake bays, although only two are active. The remaining four are blocked with stop logs. Each of the active screen bays is approximately 8 feet wide and fitted with vertical traveling screens with 5/8-inch by 3/8-inch mesh panels. Screens are rotated once per 8-hour shift for 30 minutes. A high-pressure spray removes any debris or fish that have become impinged on the screen face. Captured debris is collected in a sump for disposal. Downstream of each screen is a circulating water pump rated at 37,500 gallons per minute (gpm), for a total facility capacity of 75,000 gpm, or 108 million gallons per day (mgd) (LADWP 2005).

At maximum capacity, HGS maintains a total pumping capacity rated at 108 mgd, with a condenser flow rating of 81 mgd. On an annual basis, HGS withdraws substantially less than its design capacity due to its low generating capacity utilization (8.9 percent for 2006). When in operation and generating the maximum load, HGS can be expected to withdraw water from the ILAHC at a rate approaching its maximum capacity

2.2 SECTION 316(B) PERMIT COMPLIANCE

The CWIS currently in operation at HGS does not use technologies generally considered to be effective at reducing impingement mortality and/or entrainment. HGS conducted an ecological study from 1977 to 1981 to determine whether the CWIS was compliant with Section 316(b) of the Clean Water Act. This study was conducted when the facility withdrew substantially more water than the current capacity (397 versus 108 mgd). LARWQCB Order R4-2003-0101, adopted in 2003, states the following:

> …the study addressed the important ecological and engineering factors specified in the guidelines, demonstrated that the ecological impacts of the intake system are environmentally acceptable, and provided evidence that no modifications to design, location, or capacity of the intake structure are required. (LARWQCB 2003, Finding 14)

The order does not contain any numeric or narrative limitations regarding impingement or entrainment resulting from CWIS operation, but does require semiannual monitoring of impingement at the intake structure (coinciding with scheduled heat treatments). Based on the record available for review, HGS has been compliant with this permit requirement.

The LARWQCB has notified HGS of its intent to revisit requirements under CWA Section 316(b), including a determination of the best technology available (BTA) for minimization of adverse environmental impact, upon expiration of the current order in 2008.

3.0 WET COOLING SYSTEM RETROFIT

3.1 OVERVIEW

The current secondary treated effluent volume in the vicinity of HGS may be sufficient as a substitute for the existing once-through cooling water source (ILAHC). Its use would depend on whether transmission pipelines could be installed in the area and if any conflicts over the use and discharge of secondary treated effluent to the harbor can be addressed. In a wet cooling tower system, the use of reclaimed water as the makeup water source (as opposed to ILAHC) is an attractive alternative when considering additional benefits its use may provide, such as avoidance of conflicts with effluent limitations or air emission standards.

This study evaluates a saltwater cooling tower as a retrofit option at HGS, with the current source water (ILAHC) continuing to provide makeup water to the facility. Converting the existing once-through cooling system to a wet cooling tower will reduce the facility's current intake capacity by approximately 94 percent; rates of impingement and entrainment will decline by a similar proportion.

The wet cooling tower's configuration—size, arrangement, and location—was based on best professional judgment (BPJ) using the criteria outlined in Chapter 5 and designed to meet the performance benchmarks in the most cost-effective manner. Information not available to this study that offers a more complete facility characterization may lead to different conclusions regarding the cooling tower's physical configuration.

This study developed a conceptual design of a wet cooling tower sufficient to meet Unit 5's cooling demand at its rated output during peak climate conditions. Cost estimates are based on vendor quotes developed using the available information and the various design constraints identified at HGS.

The overall practicality of retrofitting Unit 5 will require an evaluation of factors outside the scope of this study, such as the unit's age and efficiency and its role in the overall reliability of electricity production and transmission in California, particularly the Los Angeles region.

3.2 DESIGN BASIS

3.2.1 CONDENSER SPECIFICATIONS

For this study, the wet cooling tower conceptual design selected for HGS is based on the assumption that the condenser flow rate and thermal load to each will remain unchanged from the current system. Although no provision is included to re-optimize the condenser performance for service with a cooling tower, some modifications to the condenser (tube sheet and water box reinforcement) may be necessary to handle the increased water pressures that will result from the increased total pump head required to raise water to the cooling tower riser elevation.[2] The practicality and difficulty of these modifications are dependent on Unit 5's age and configuration

[2] In this context, re-optimization refers to a comprehensive condenser overhaul that reduces thermal efficiency losses associated with a wet cooling tower's higher circulating water temperatures. Modifications discussed in this study are generally limited to reinforcement measures that enable the condenser to withstand increased water pressures.

but are assumed to be feasible at HGS. Additional costs for condenser modifications are included in the discussion of capital expenditures (Section 4.0).

Information provided by HGS was largely used as the basis for the cooling tower design. In some cases, the data were incomplete or conflicted with values obtained from other sources. Where possible, questionable values were verified or corrected using other known information about the condenser.

Parameters used in the development of the cooling tower design are summarized in Table E–5.

Table E–5. Condenser Design Specifications

	Unit 5
Thermal load (MMBTU/hr)	652.5
Surface area (ft^2)	70,000
Condenser flow rate (gpm)	56,400
Tube material	AL6XN (stainless steel)
Heat transfer coefficient ($BTU/hr \cdot ft^2 \cdot °F$)	429
Cleanliness factor	0.85
Inlet temperature (°F)	65
Temperature rise (°F)	23.15
Steam condensate temperature (°F)	100.3
Turbine exhaust pressure (in. HgA)	1.95

For example, the Unit 5 condenser specification sheet describes the condenser's original design when it was placed into service in 1946. As part of the 1992 repowering project, the condenser was re-tubed with a different tube gage (20 BWG versus 18 BWG). No other changes (e.g., materials, calculations, etc.) were indicated.

If the tube gage was changed but the all other parameters remained the same, the heat transfer coefficient would also change. This affects the system's thermal performance and influences the size estimate for the cooling tower. Using other known condenser data (tube material, flow, size, etc.), and following Heat Exchange Institute guidelines, the heat transfer coefficient was recalculated to 429 at the design condenser inlet temperature (65º F). This differs from the value reported on the condenser data sheet (550).

Calculations based on the recalculated heat transfer coefficient and other design specifications yield a higher backpressure at the design water temperature (65º F) than initially reported. This adjusted design backpressure (1.95 inches HgA) appears to be more in line with actual values recorded by HGS when Unit 5 is operating at maximum load.

Calculations are based solely on the data provided. Other factors not available for evaluation in this study may result in different conclusions.

3.2.2 AMBIENT ENVIRONMENTAL CONDITIONS

HGS is located in Los Angeles County in the Wilmington section of the city of Los Angeles. Cooling water is withdrawn from a shoreline intake in ILAHC. Inlet temperature data were not available from HGS. Instead, surface water temperatures used in this analysis were based on monthly average coastal water temperatures as reported in the NOAA *Coastal Water Temperature Guide for Los Angeles, CA* (NOAA 2007).

The wet bulb temperature used in the development of the overall cooling tower design was obtained from American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) publications. Data for Los Angeles indicate a 1 percent ambient wet bulb temperature of 69° F (ASHRAE 2006). An approach temperature of 12° F was selected based on the site configuration and vendor input. At the design wet bulb and approach temperatures, the cooling towers will yield “cold” water at a temperature of 78° F.

Monthly maximum wet bulb temperatures used in the development of energy penalty estimates in Section 4.6 were calculated using data obtained from the National Climatic Data Center (NCDC) for San Pedro, CA (NCDC 2006). Climate data used in this analysis are summarized in Table E–6.

Table E–6. Surface Water and Ambient Wet Bulb Temperatures

	Surface (°F)	Ambient wet bulb (°F)
January	58.0	54.4
February	58.0	56.2
March	60.0	57.8
April	60.0	60.8
May	61.0	65.8
June	63.0	68.4
July	66.0	69.4
August	68.0	69.5
September	67.0	65.6
October	66.0	60.4
November	64.0	56.4
December	60.0	55.6

3.2.3 LOCAL USE RESTRICTIONS

3.2.3.1 NOISE

Industrial development in the vicinity of HGS is covered by the City of Los Angeles Municipal Code and the Wilmington-Harbor City Community Plan. Both plans outline narrative criteria to be used as a guide for future development, but do not identify numeric noise limits for new construction. Based on consultation with the City of Los Angeles Department of Building and Safety, any measures limiting noise from a wet cooling tower would be addressed through a conditional use permit that evaluates the specific design of the project. Given the heavily industrialized nature of the area, however, and the lack of any residences or sensitive coastal resources nearby, noise impacts are not expected to be an issue. This study used an ambient noise limit of 70 dBA at a distance of 800 feet in selecting the design elements of the wet tower installation. Accordingly, the final design selected for HGS does not require any measures that specifically address noise, such as low-noise fans or barrier walls.

3.2.3.2 BUILDING HEIGHT

HGS is located within the M3 zone according to the planning and zoning code for Los Angeles. This zone is dedicated to light and heavy industry. The building code does not establish specific criteria for building height and instead relies on conditional use permitting that evaluates the specific design of the project. Given the existing height of the current structures at HGS and others in the area, this study selected a height restriction of 50 feet above grade level. The height of the wet cooling tower designed for HGS, from grade level to the top of the fan deck, is 44 feet.

3.2.3.3 PLUME ABATEMENT

Local zoning ordinances do not contain any specific criteria for addressing any impact associated with a wet cooling tower plume. Likewise, community standards for assessing the visual impact associated with a cooling tower plume cannot be determined within the scope of this study. Given the heavily industrialized nature of the area, visual plume impacts are not expected to be a concern with a wet cooling tower at HGS. Accordingly, no plume abatement technologies are included for HGS.

3.2.3.4 DRIFT AND PARTICULATE EMISSIONS

Drift elimination measures that are considered best available control technology (BACT) are required for all cooling towers evaluated in this study, regardless of their location. State-of-the-art drift eliminators are included for each cooling tower cell at HGS, with an accepted efficiency of 0.0005 percent. Because cooling tower PM_{10} emissions are a function of the drift rate, drift eliminators are also considered BACT for PM_{10} emissions from wet cooling towers. This efficiency can be verified by a proper in situ test, which accounts for site-specific climate, water, and operating conditions. Testing based on the Cooling Tower Institute's Isokinetic Drift Test Code is required at initial start-up on only one representative cell of each tower for an approximate cost of $60,000 per test (CTI 1994). This cost is not itemized in the final analysis and is instead included as part of the indirect cost estimate (Section 4.3).

3.2.3.5 FACILITY CONFIGURATION AND AREA CONSTRAINTS

The site's existing configuration and the total available area may require reconfiguration of existing structures or purchase of adjoining lots to enable placement of the cooling tower as designed. As shown in Figure E–3, little room is currently available at the HGS property, with most areas occupied by the power block, switchyard, or fuel tanks. The most practical wet cooling tower location is in the southwest corner of the property, immediately west of Unit 5 and the intake screens (Area 1).

To accommodate a more ideal placement of the 250-foot-long cooling tower, a portion of the area abutting Area 1 would have to be purchased or otherwise secured for use. According to records obtained from the Los Angeles County Assessor, parcels immediately west of the HGS property are owned by the city of Long Beach and believed to be vacant (LACA 2007). The cost and feasibility of obtaining this land was not evaluated in detail.

Area 2 is the only other location at HGS that could conceivably accommodate a wet cooling tower, although it is currently occupied by unidentified structures, which would require removal and/or relocation. Relocation of the switchyard was not considered. The cooling tower configuration developed for this study assumes the availability of Area 1.

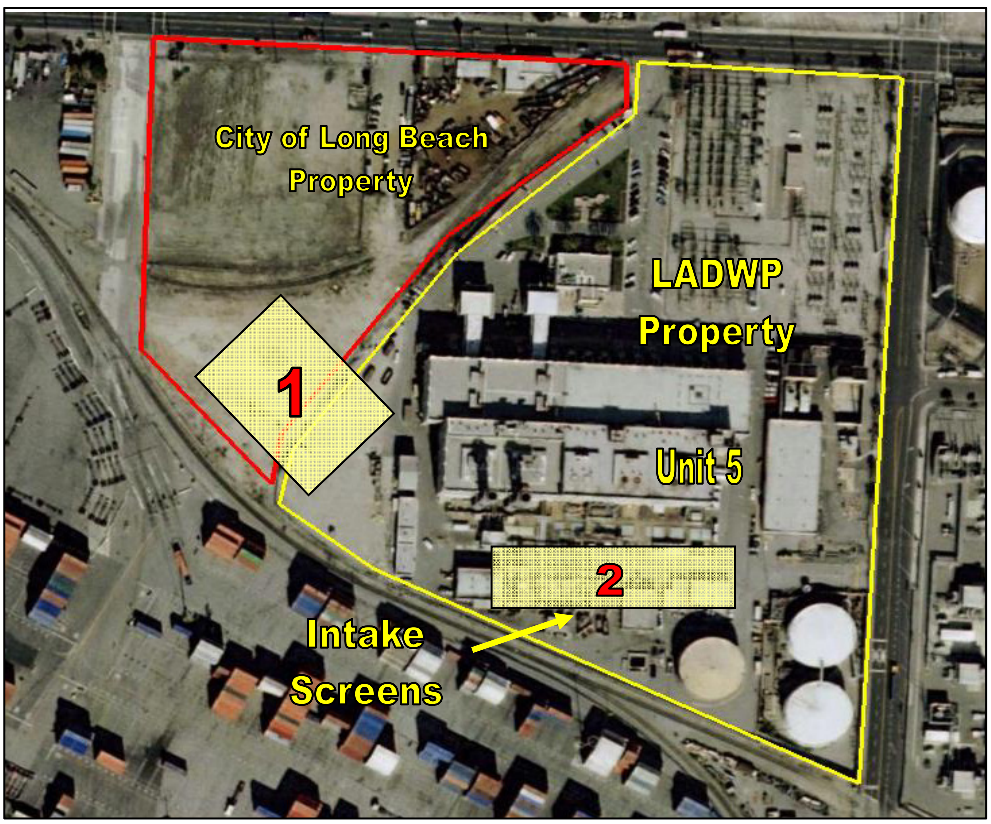

Figure E–3. Site Boundaries

3.3 CONCEPTUAL DESIGN

Based on the design constraints discussed above, one wet cooling tower was selected to replace the current once-through cooling system that serves Unit 5. The tower is configured in a multicell, inline arrangement.

3.3.1 SIZE

The tower is constructed over a concrete collection basin 4 feet deep. The basin is larger than the tower structure's footprint, extending an additional 2 feet in each direction. The concrete used for construction is suitable for saltwater applications. The principal tower material is fiberglass reinforced plastic (FRP), with stainless steel fittings. These materials are more resistant to the higher corrosive effects of saltwater.

The size of the tower is primarily based on the thermal load rejected to the tower by the surface condenser and a 12° F approach to the ambient wet bulb temperature. Flow rates through each condenser remain unchanged.

General characteristics of the wet cooling towers selected for HGS are summarized in Table E–7.

Table E–7. Wet Cooling Tower Design

	Tower 1 (Unit 5)
Thermal load (MMBTU/hr)	652.5
Circulating flow (gpm)	56,400
Number of cells	5
Tower type	Mechanical draft
Flow orientation	Counterflow
Fill type	Modular splash
Arrangement	Inline
Primary tower material	FRP
Tower dimensions (l x w x h) (ft)	240 x 48 x 44
Tower footprint with basin (l x w) (ft)	244 x 52

3.3.2 LOCATION

The initial site selection for each tower was based on the desire to locate each tower as close as possible to its respective generating unit to minimize the supply and return pipe distances and any increases in total pump head and brake horsepower. Area 1 is located on the opposite side of the facility from Unit 5. To minimize interference with underground structures, this study assumes that supply and return piping can be routed to the existing intake forebay and reuse piping already connected to Unit 5. Figure E-4 identifies the approximate location of each tower and supply and return piping.

3.3.3 PIPING

The main supply and return pipelines for the tower will be located underground and made of prestressed concrete cylinder pipe (PCCP) suitable for saltwater applications. These pipes are 72 inches in diameter. Pipes connecting the condenser to the supply and return lines are made of FRP and placed above ground on pipe racks. Above-ground placement avoids the potential disruption that may be caused by excavation in and around the power block.

All riser piping (extending from the foot of the tower to the water distribution level) is constructed of FRP.

Potential interference with underground obstacles and infrastructure is a concern, particularly at existing sites that are several decades old and have been substantially modified or rebuilt in the interim. Avoidance of these obstacles is considered to the degree practical in this study. Associated costs are included in the contingency estimate and are generally higher than similar estimates for new facilities (Section 4.3).

Appendix B details the total quantity of each pipe size and type for HGS.

Figure E-4. Cooling Tower Location

3.3.4 FANS AND PUMPS

Each tower cell uses an independent single-speed fan. The fan size and motor power are the same for each cell in the tower.

This analysis includes new pumps to circulate water between the condenser and cooling tower. Pumps are sized according to the flow rate for the tower, the relative distance between the tower and condenser, and the total head required to deliver water to the top of each cooling tower riser. A separate, multilevel pump house is constructed for the tower and sized to accommodate the motor control centers (MCCs) and appropriate electrical switchgear. The electrical installation includes all necessary transformers, cabling, cable trays, lighting, and lightning protection. A 50-ton overhead crane is also included to allow for pump servicing.

Fan and pump characteristics associated with wet cooling towers at HGS are summarized in Table E–8. The net electrical demand of fans and new pumps is discussed further as part of the energy penalty analysis in Section 4.6.

Table E–8. Cooling Tower Fans and Pumps

		Tower 1 (Unit 5)
Fans	Number	5
	Type	Single speed
	Efficiency	0.95
	Motor power (hp)	211
Pumps	Number	2
	Type	50% recirculating Mixed flow Suspended bowl Vertical
	Efficiency	0.88
	Motor power (hp)	693

3.4 ENVIRONMENTAL EFFECTS

Converting the existing once-through cooling system at HGS to wet cooling towers will significantly reduce the intake of seawater from ILAHC and will presumably reduce impingement and entrainment by a similar proportion. Because closed-cycle systems will almost always result in condenser cooling water temperatures higher than those found in a comparable once-through system, wet towers will increase the operating heat rates of HGS's combined-cycle unit, thereby decreasing the facility's overall efficiency. Additional power will also be consumed by the tower fans and circulating pumps.

Depending on how HGS chooses to address this change in efficiency, total stack emissions may increase for pollutants such as PM_{10}, SO_x, and NO_x, and may require additional control measures (e.g., electrostatic precipitation, flue gas desulfurization, and selective catalytic reduction) or the purchase of emission credits to meet air quality regulations. The availability of emission reduction credits (ERCs) and their associated cost was not evaluated as part of this study. Both factors, however, may limit the air emission compliance options available to HGS.

No control measures are currently available for CO_2 emissions, which will increase, on a per-kWh basis, by the same proportion as any change in the heat rate. The towers themselves will constitute an additional source of PM_{10} emissions, the annual mass of which will largely depend on Unit 5's capacity utilization rate.

If HGS retains its NPDES permit to discharge wastewater to the West Basin of ILAHC with a wet cooling tower system, it may have to address revised effluent limitations resulting from the substantial change in the discharge quantity and characteristics. Thermal impacts from the current once-through system, if any, will be minimized with a wet cooling system.

3.4.1 AIR EMISSIONS

HGS is located in the South Central Coast air basin. Air emissions are permitted by the South Coast Air Quality Management District (SCAQMD) (Facility ID 800170).

Drift volumes are expected to be within the range of 0.5 gallons for every 100,000 gallons of circulating water in the tower. At HGS, this corresponds to a rate of approximately 0.28 gpm based on the maximum flow. No drift-related impacts are expected.

Total PM_{10} emissions from the HGS cooling tower is a function of the number of hours in operation, the overall water quality in the tower, and the evaporation rate of drift droplets prior to deposition on the ground. Makeup water at HGS will be obtained from the same source currently used for once-through cooling water (ILAHC). This water is drawn through the harbor from the Pacific Ocean and is the same as marine water with respect to the total dissolved solids (TDS) concentration. At 1.5 cycles of concentration and assuming an initial TDS value of 35 parts per thousand (ppt), the water within the cooling towers will reach a maximum TDS level of roughly 53 ppt. Any drift droplets exiting the tower will have the same TDS concentration.

The cumulative mass emission of PM_{10} from HGS will increase as a result of the direct emissions from the cooling tower itself. Stack emissions of PM_{10}, as well as SO_x, NO_x, and other pollutants, will increase due to the drop in fuel efficiency, although the cumulative increase will depend on actual operations and emission control technologies currently in use. Maximum drift and PM_{10} emissions from the cooling towers are summarized in Table E–9.[3]

Data summarizing the total facility emissions for these pollutants in 2005 are presented in Table E–10 (CARB 2005). In 2005, HGS operated at an annual capacity utilization rate of 13.8 percent.

[3] This is a conservative estimate that assumes all dissolved solids present in drift droplets will be converted to PM_{10}. Studies suggest this may overestimate actual emission profiles for saltwater cooling towers (Chapter 4).

Using this rate, the additional PM_{10} emissions from the cooling tower would increase the facility total by approximately 4.5 tons/year, or 530 percent. [4]

Table E-9. Full Load Drift and Particulate Estimates

	PM_{10} (lbs/hr)	PM_{10} (tons/year)	Drift (gpm)	Drift (lbs/hr)
Tower 1	7	32	0.28	141
Total HGS PM_{10} and drift emissions	**7**	**32**	**0.28**	**141**

Table E-10. 2005 Emissions of SO_x, NO_x, PM_{10}

Pollutant	Tons/year
NOx	23.6
SOx	0.56
PM10	0.85

3.4.2 MAKEUP WATER

The volume of makeup water required by the cooling tower at HGS is the sum of evaporative loss and the blowdown volume required to maintain the tower's circulating water at the design TDS concentration. Drift expelled from the tower represents an insignificant volume by comparison and is accounted for by rounding up evaporative loss estimates. Makeup water volumes are based on design conditions, and may fluctuate seasonally depending on climate conditions and facility operations. Wet cooling towers will reduce once-through cooling water withdrawals from ILAHC by approximately 94 over the current design intake capacity.

Table E-11. Makeup Water Demand

	Tower circulating flow (gpm)	Evaporation (gpm)	Blowdown (gpm)	Total makeup water (gpm)
Tower 1	56,400	1,000	2,100	**3,100**
Total HGS makeup water demand	**56,400**	**1,000**	**2,100**	**3,100**

One circulating water pump, rated at 37,500 gpm, which is currently used to provide once-through cooling water to the facility, will be retained in a wet cooling system to provide makeup water to the cooling tower. The retained pump's capacity exceeds the makeup demand by approximately 34,000 gpm. Any excess capacity will be routed through a bypass conduit and returned to the wet well at a point located behind the intake screens. Recirculating the excess capacity in this manner reduces additional cost that would be incurred if new pumps were required while maintaining the desired flow reduction. The intake of new water, measured at the intake screens, will be equal to the cooling tower's makeup water demand. Figure E–5 presents a schematic of this configuration.

[4] 2006 emission data are not currently available from the Air Resources Board Web site. For consistency, the comparative increase in PM_{10} emissions estimated here is based on the 2005 HGS capacity utilization rate instead of the 2006 rate presented in Table E-4. All other calculations in this chapter use the 2006 value.

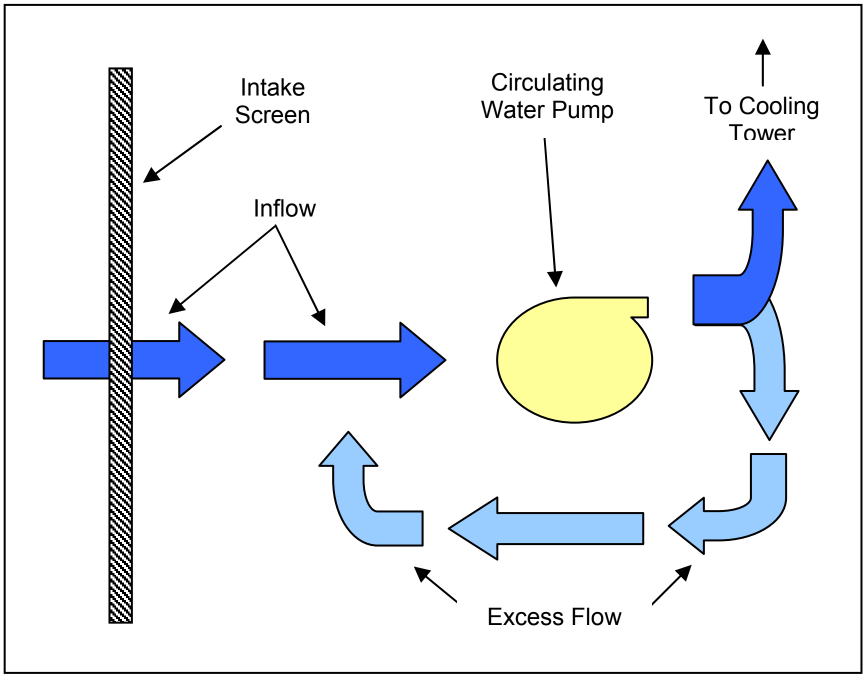

Figure E-5. Schematic of Intake Pump Configuration

The existing once-through cooling system at HGS does not treat water withdrawn from ILAHC, with the exception of screening for debris and larger organisms and periodic chlorination to control biofouling in the condenser tubes. Biofouling is also controlled by passing rubber scrubbers through the condensers and removing any fouling or growth. Conversion to a wet cooling tower system will not interfere with chlorination or scrubbing operations.

Makeup water will continue to be withdrawn from ILAHC.

The wet cooling tower system proposed for HGS includes water treatment for standard operational measures, i.e., corrosion inhibitors, biocides, and anti-scaling agents. An allowance for these additional chemical treatments is included in annual O&M costs. It is assumed that the current once-through cooling water quality will be acceptable for use in a seawater cooling tower (with continued screening and chlorination) and will not require any pretreatment to enable its use.

3.4.3 NPDES PERMIT COMPLIANCE

At maximum operation, the HGS wet cooling towers will result in an effluent discharge of 3.0 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, regeneration wastes, and cleaning wastes. These low-volume wastes may add an additional 0.0125 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, HGS will be required to modify its existing individual wastewater discharge (NPDES) permit.

Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0000361as implemented by LARWQCB Order R4-2003-0101. All wastewaters are discharged to the West Basin of ILAHC. The existing order contains effluent limitations based on the California Toxics Rule (CTR) and 1972 Thermal Plan.

HGS will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities (40 CFR 423.13(d)(1)). These ELGs set numeric limitations for chromium and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity). Because ELGs are technology-based limitations, mixing zones or dilution factors are not applicable when determining compliance; limits must be met at the point of discharge from the cooling tower prior to commingling with any other waste stream. ELGs for cooling tower blowdown target priority pollutants that are contributed by maintenance chemicals and do not apply when limits may be exceeded as a result of background concentrations or other sources. Further discussion can be found in Chapter 4, Section 3.6.

Conversion to wet cooling towers will alter the volume and composition of a facility's wastewater discharge because wet towers concentrate certain pollutants in the effluent waste stream. The cooling towers designed for HGS operate at 1.5 cycles of concentration, i.e., the blowdown discharge will contain a dissolved solids concentration 50 percent higher than the makeup water.

Effluent data were not available for review for HGS, but the 2002 303(d) list identifies several segments of the Los Angles Harbor as impaired for cadmium, chromium, lead, mercury, and zinc (USEPA 2002). Total maximum daily loads (TMDLs) for the Los Angeles Harbor may be established in the future, with specific load allocations (LAs) for these pollutants applied to HGS.

Changes to discharge composition may affect compliance with water quality criteria included in the SIP. If compliance with these objectives becomes problematic, alternative treatment or discharge methods may be necessary. Compliance may be achieved by altering the discharge configuration in such a way as to increase dilution (e.g., diffuser ports), or by seeking a mixing zone and dilution credits as permissible under the SIP and Basin Plan. Alternately, some low volume waste streams (e.g., boiler blowdown, laboratory drains) may be diverted, with necessary permits, for treatment at a POTW.

If more pollutant-specific treatment methods, such as filtration or precipitation technologies, become necessary to meet WQBELs, the initial capital cost may range from $2 to $5.50 per 1,000 gallons of treatment capacity, with annual costs of approximately $0.5 per gallon of capacity, depending on the method of treatment (FRTR 2002). Hazardous material disposal fees and permits would further increase costs.

This evaluation did not include alternative discharge or effluent treatment measures in the conceptual design because the variables used to determine final WQBELs, which would be used to determine the type and scope of the desired compliance method, cannot be quantified here. Likewise, the final cost evaluation (Section 4.0) does not include any allowance for these possibilities.

Thermal discharge standards are based on narrative criteria established for discharges within enclosed bays under the Thermal Plan, which requires existing discharges of elevated-temperature wastes to comply with effluent limitations necessary to assure the protection of designated beneficial uses. The LARWQCB has implemented this provision in Order R4-2003-0101 by establishing a maximum discharge temperature of 94º F during normal operations (LARWQCB 2003). Information available for review indicates HGS has consistently been able to comply with this requirement. Because cooling tower blowdown will be taken from the "cold" side of the tower, conversion to a wet cooling system will significantly reduce the discharge temperature (to less than 80º F) and the size of any related thermal plume in the receiving water.

3.4.4 RECLAIMED WATER

Reclaimed or alternative water sources used in conjunction with wet cooling towers could eliminate all surface water withdrawals at HGS. Doing so would completely eliminate impingement and entrainment concerns, and might enable the facility to avoid possible effluent quality and permit compliance issues, depending on the quality of reclaimed water available for use. In addition, wet cooling towers using reclaimed water would be expected to have lower PM10 emissions due to the lower TDS levels. The California State Water Resources Control Board (SWRCB), in 1975, issued a policy statement requiring the consideration of alternative cooling methods in new power plants, including reclaimed water, over the use of freshwater (SWRCB 1975). There is no similar policy regarding marine waters, but the clear preference of state agencies is to encourage alternative cooling methods, including reclaimed water, wherever possible.

The present volume of available secondary treated water within a 15-mile radius of HGS can meet the current once-through cooling demand for Unit 5 (81 mgd). In lieu of secondary treated water as a replacement for once-through cooling, reclaimed water can be used as makeup water in cooling towers but must meet tertiary treatment and disinfection standards under California Code of Regulations (CCR) Title 22. If the reclaimed water is not treated to the required levels, HGS would be required to provide sufficient treatment prior to use in the cooling towers.

Currently, the West Basin Municipal Water District (WBMWD) treats approximately 30 mgd of secondary water from Hyperion WWTP to tertiary standards. This water is used for various projects throughout the South Bay region, such as the seawater barrier conservation project to protect underground aquifers. WBMWD's current available capacity is insufficient to meet the makeup water demand for the wet cooling towers at HGS (WBMWD 2007).

Four publicly owned treatment works (POTWs) were identified within a 15-mile radius of HGS, with a combined discharge capacity of 403 mgd. Figure E-6 shows the relative locations of these facilities to HGS.

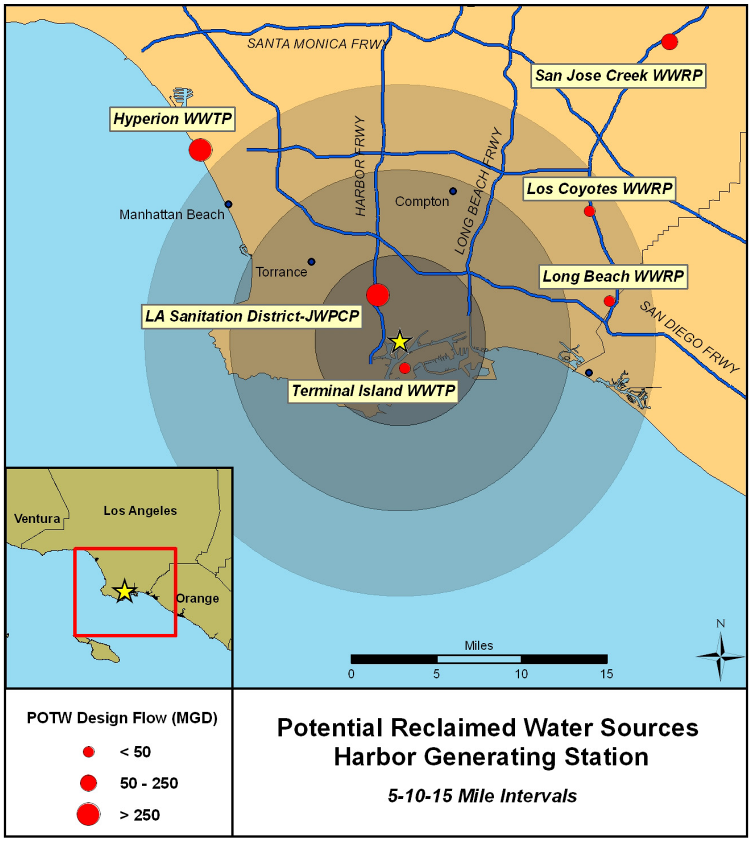

Figure E–6. Reclaimed Water Sources

- *Terminal Island Wastewater Treatment Plant—San Pedro*
  Discharge volume: 20 mgd
  Distance: 1.5 miles S
  Treatment level: 10% tertiary; 90% secondary

  Tertiary treated water is used for local irrigation. A previous study to assess the feasibility of using Terminal Island's reclaimed water at HGS determined the water quality (pH) would have adverse effects on the condenser and cooling system, although treatment systems could be installed onsite to condition the water to an acceptable pH level.[5]

- *Los Angeles Sanitation District, Joint Water Pollution Control Plant (JWPCP)—Carson*
  Discharge volume: 330 mgd
  Distance: 2.5 miles NW
  Treatment level: Secondary

  The facility representative at JWPCP indicated that the effluent is not currently considered a potential source of reclaimed water for irrigation due to high TDS concentrations (brine from the Hyperion WWTP is treated at Carson), but the suitability for use as a makeup water source is not currently known. TDS levels may be less than normally found in seawater and

[5] This study was referenced in documents provided by LADWP but not available for review.

thus may be at least comparable to the current makeup water source at HGS. In the future, a portion of the effluent may be used for a new hydrogen plant under consideration by BP (formerly British Petroleum), but no formal agreement currently exists. Even with such an agreement, sufficient capacity would remain to satisfy the full makeup water demand for a freshwater tower at HGS (2 to 5 mgd).

- *Long Beach Wastewater Treatment Plant—Long Beach*
  Discharge volume: 20 mgd
  Distance: 10 miles E
  Treatment level: Tertiary

  Approximately 50 percent is currently used for irrigation in the vicinity of the plant. The remaining capacity could supply the makeup water demand for a freshwater cooling tower at HGS (2 to 5 mgd).

- *Los Coyotes Wastewater Reclamation Plant—Cerritos*
  Discharge volume: 33 mgd
  Distance: 13 miles NE
  Treatment level: 30 % tertiary; 70 % secondary

  Approximately 10 MGD are treated to tertiary standards and reused for irrigation at various locations in the area, leaving approximately 23 mgd available as a makeup water source. This volume is sufficient to provide the makeup flow requirement for a freshwater tower, although HGS would have to make arrangements for treatment prior to use.

The nearest facility with sufficient capacity to satisfy HGS's makeup demand (2 to 5 mgd as a freshwater tower) is located approximately 1.5 miles from the site (Terminal Island). Installation of a transmission pipeline may face significant obstacles in crossing areas of the Los Angeles Harbor. Based on data compiled for this study and others, the estimated installed cost of an 18--inch prestressed concrete cylinder pipe, sufficient to provide 5 mgd to HGS, is $280 per linear foot, or approximately $1.5 million per mile. Additional considerations, such as pump capacity and any required treatment, would increase the total cost. Likewise, obstacles presented by navigational concerns across Los Angeles Harbor may increase costs.

Regulatory concerns beyond the scope of this investigation, however, may make reclaimed water (as a makeup water source) comparable or preferable to saltwater from ILAHC. Reclaimed water may enable HGS to eliminate potential conflicts with water discharge limitations or reduce PM_{10} emissions from the cooling tower, which is a concern given the South Coast air basin's current nonattainment status.

At any facility where wet cooling towers are a feasible alternative, reclaimed water may be used as a makeup water source. The practicality of its use, however, depends on the overall cost, availability, and additional environmental benefit that may occur.

3.4.5 THERMAL EFFICIENCY

A wet cooling tower at HGS will increase the condenser inlet water temperature by a range of 9 to 18° F above the surface water temperature, depending on the ambient wet bulb temperature at the time. Unit 5 is designed to operate at the conditions described in Table E–12. The resulting monthly difference between once-through and wet cooling tower condenser inlet temperatures is described in Figure E–7.

Table E–12. Design Thermal Conditions

	Unit 5
Design backpressure (in. HgA)	1.95
Design water temperature (°F)	65
Turbine inlet temp (°F)	900
Turbine inlet pressure (psia)	850
Full load heat rate (BTU/kWh) [a]	8,500

[a] CEC 2002.

Backpressures for the once-through and wet cooling tower configurations were calculated for each month using the design criteria described in the sections above and ambient climate data. In general, backpressures associated with the wet cooling tower were elevated by 0.5 to 1.1 inches HgA compared with the current once-through system (Figure E–7).

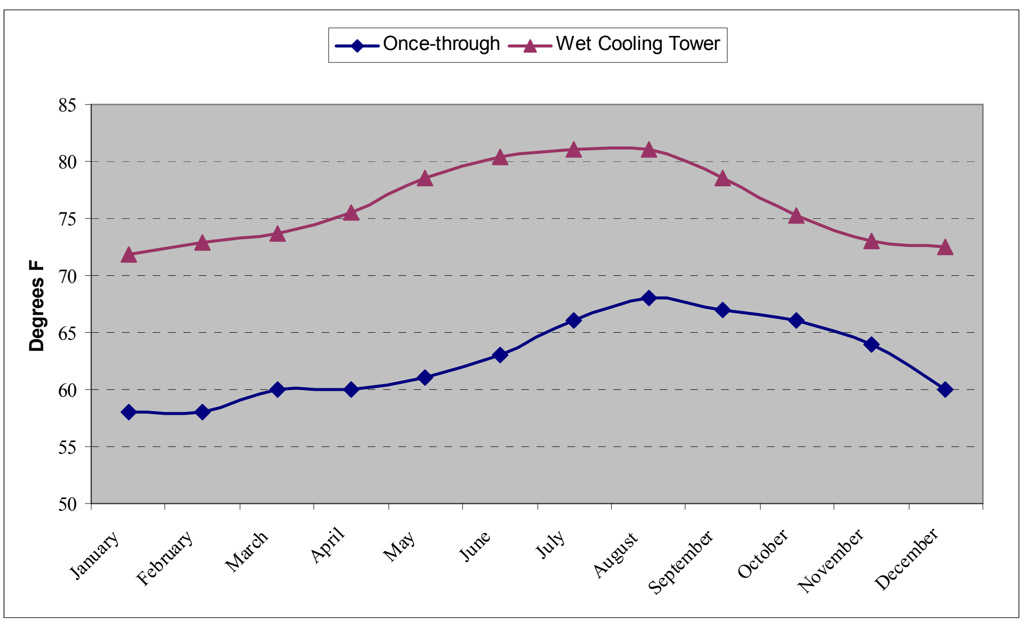

Figure E–7. Condenser Inlet Temperatures

Heat rate adjustments were calculated by comparing the theoretical change in available energy that occurs at different turbine exhaust backpressures, assuming the thermal load and turbine inlet pressure remain constant, i.e., at the full load rating.[6] The relative change at different backpressures was compared with the value calculated for the design conditions (i.e., at design turbine inlet and exhaust backpressures) and plotted as a percentage of the full load operating heat rate (Figure E–8) to develop estimated correction curve (Figure E–9).

The difference between the estimated once-through and closed-cycle heat rates for each month represents the approximate heat rate increase that would be expected when converting to wet cooling towers.

Table E–13 summarizes the annual average heat rate increase for each unit as well as the increase associated with the peak demand period of July-August-September. Monthly values were used to calculate the monetized value of these heat rate changes (Section 4.6). Month-by-month calculations are presented in Appendix A.

Table E–13. Summary of Estimated Heat Rate Increases

	Unit 5
Peak (July-August-September)	0.59%
Annual average	0.48%

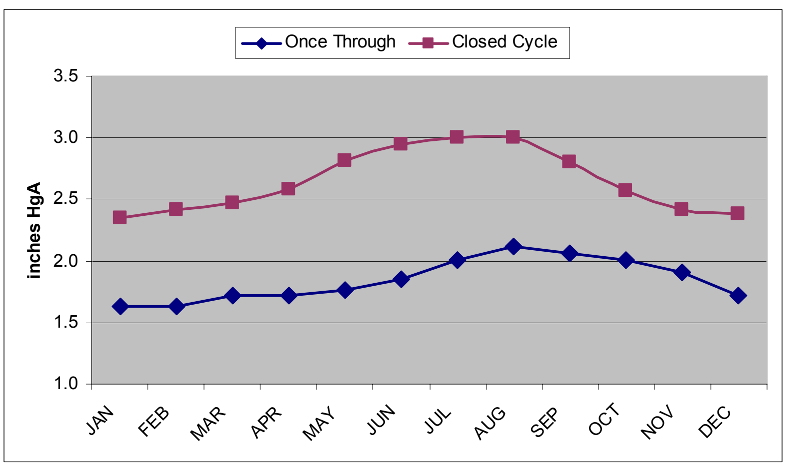

Figure E–8. Estimated Backpressures (Unit 5)

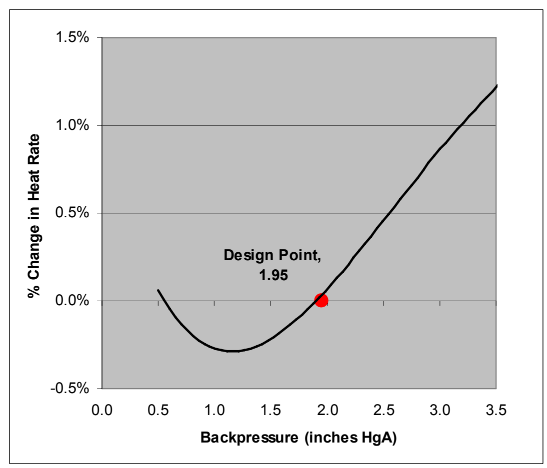

Figure E–9. Estimated Heat Rate Correction (Unit 5)

[6] Changes in thermal efficiency estimated for HGS are based on the design specifications provided by the facility. This may not reflect system modifications that might influence actual performance. In addition, the age of the units and the operating protocols used by HGS might result in different calculations.

4.0 RETROFIT COST ANALYSIS

The wet cooling system retrofit estimate for HGS is based on incorporating a conventional wet cooling tower as a replacement for the existing once-through system for Unit 5. Standard cost elements for this project include the following:

- Direct (cooling tower installation, civil/structural, mechanical, piping, electrical, and demolition)
- Indirect (smaller project costs not itemized)
- Contingency (allowance for unknown project variables)
- Revenue loss from shutdown (net loss in revenue during construction phase)
- Operations and maintenance (non–energy related cooling tower operations)
- Energy penalty (includes increased parasitic use from fans and pumps as well as decreased thermal efficiency)

The cost analysis does not include allowances for elements that are not quantified in this study, such as land acquisition, effluent treatment, or air emission reduction credits. The methodology used to develop cost estimates is discussed in Chapter 5.

4.1 COOLING TOWER INSTALLATION

In general, the cooling tower configuration selected for HGS conforms to a typical design; noise control, or plume abatement measures were not required. Table E–14 summarizes the design-and-build cost estimate for each tower developed by vendors, inclusive of all labor and management required for their installation.

Table E–14. Wet Cooling Tower Design-and-Build Cost Estimate

	Unit 5
Number of cells	5
Cost/cell ($)	520,000
Total HGS D&B cost ($)	2,600,000

4.2 OTHER DIRECT COSTS

A significant portion of wet cooling tower installation costs result from the various support structures, materials, equipment and labor necessary to prepare the cooling tower site and connect the towers to the condenser. At HGS, these costs comprise approximately 50 percent of the initial capital cost. Line item costs are detailed in Appendix B.

Deviations from or additions to the general cost elements discussed in Chapter 5 are discussed below. Other direct costs (non–cooling tower) are summarized in Table E–15.

- *Civil, Structural, and Piping*
  The HGS site configuration allows the tower to be located within relative proximity to Unit 5.
- *Mechanical and Electrical*
  Initial capital costs in this category reflect the new pumps (two) to circulate cooling water between the towers and condensers. No new pumps are required to provide makeup water from ILAHC. Electrical costs are based on the battery limit after the main feeder breakers.
- *Demolition*
  No demolition costs are required.

Table E–15. Summary of Other Direct Costs

	Equipment ($)	Bulk material ($)	Labor ($)	HGS total ($)
Civil/structural/piping	1,000,000	3,200,000	3,100,000	**7,300,000**
Mechanical	2,100,000	0	200,000	**2,300,000**
Electrical	1,300,000	1,500,000	1,000,000	**3,800,000**
Demolition	0	0	0	**0**
Total HGS other direct costs	**4,400,000**	**4,700,000**	**4,300,000**	**13,400,000**

4.3 INDIRECT AND CONTINGENCY

Indirect costs are calculated as 25 percent of all direct costs (civil/structural, mechanical, electrical, demolition, and cooling towers).

An additional allowance is included for condenser water box and tube sheet reinforcement to withstand the increased pressures associated with a recirculating system. Each condenser may require reinforcement of the tube sheet bracing with 6-inch x 1-inch steel, and water box reinforcement/replacement with 5/8-inch carbon steel. Based on the estimates outlined in Chapter 5, a conservative estimate of 5 percent of all direct costs is included to account for possible condenser modifications.

The contingency cost is calculated as 25 percent of the sum of all direct and indirect costs, including condenser reinforcement. At HGS, potential costs in this category include relocating or demolishing small buildings and structures and potential interferences from underground structures.

Subsidence has been an ongoing concern in the Los Angeles Harbor area. Seawater intrusion or the instability of sandy soils may require additional pilings to support any large structures built at the site. Initial capital costs are summarized in Table E–16.

Table E–16. Summary of Initial Capital Costs

	Cost ($)
Cooling towers	2,600,000
Civil/structural/piping	7,300,000
Mechanical	2,300,000
Electrical	3,800,000
Demolition	0
Indirect cost	4,000,000
Condenser modification	800,000
Contingency	5,200,000
Total HGS capital cost	**26,000,000**

4.4 SHUTDOWN

A portion of the work relating to installing wet cooling towers can be completed without significant disruption to the operations of HGS. Units will be offline depending on the length of time it takes to integrate the new cooling system and conduct acceptance testing. For HGS, a conservative estimate of 4 weeks for Unit 5 was developed. Based on 2006 generating output, however, no shutdown is forecast for either unit. Therefore, the cost analysis for HGS does not include any loss of revenue associated with shutdown.

This analysis did not consider shutdown with respect to the required availability of a particular generating unit, nor can it automatically be assumed that the generating profile for 2006 will be the same in each subsequent year. Net output data from 2006 may not reflect any contractual obligations that mandate a particular unit's availability during a given time period.

4.5 OPERATIONS AND MAINTENANCE

Operations and maintenance (O&M) costs for a wet cooling tower system at HGS include routine maintenance activities; chemicals and treatment systems to control fouling and corrosion in the towers; management and labor; and an allowance for spare parts and replacement. Annual costs are calculated based on the combined tower flow rate using a base cost of $4.00/gpm in Year 1 and $5.80/gpm in Year 12, with an annual escalator of 2 percent (USEPA 2001). Year 12 costs increase based on the assumption that maintenance needs, particularly for spare parts and replacements, will be greater for years 12–20. Annual O&M costs, based on the design circulating water flow for the two cooling towers at HGS (56,400 gpm), are presented in Table E–17. These costs reflect maximum operation.

Table E-17. Annual O&M Costs (Full Load)

	Year 1 cost ($)	Year 12 cost ($)
Management/labor	56,400	81,780
Service/parts	90,240	130,848
Fouling	78,960	114,492
Total HGS O&M cost	225,600	327,120

4.6 ENERGY PENALTY

The energy penalty is divided into two components: increased parasitic use from the added electrical demand from tower fans and pumps; and the decrease in thermal efficiency from elevated turbine backpressures. Monetizing the energy penalty at HGS requires some assumption as to how the facility will choose to alter its operations to compensate for these changes, if at all. One option would be to accept the reduced amount of revenue-generating electricity available for sale and absorb the economic loss ("production loss option"). A second option would be to increase the firing rate to the turbine (i.e., consume more fuel) and produce the same amount of revenue-generating electricity as had been obtained with the once-through cooling system ("increased fuel option"). The degree to which a facility is able, or prefers, to operate at a higher firing rate, however, produces the more likely scenario—some combination of the two.

Ultimately, the manner in which HGS would alter operations to address efficiency changes is driven by considerations unknown to this study (e.g., corporate strategy, contractual obligations, operating protocols and turbine pressure tolerances). In all summary cost estimates, this study calculates the energy penalty's monetized value by assuming the facility will use the increased fuel option to compensate for reduced efficiency and generate the amount of electricity equivalent to the estimated shortfall. With this option, the energy penalty is equivalent to the financial cost of additional fuel and is nominally less costly than the production loss option. This option, however, may not reflect long-term costs such as increased maintenance or system degradation that may result from continued operation at a higher-than-designed turbine firing rate.[7]

The energy penalty for HGS is calculated by first estimating the increased parasitic demand from the cooling tower pumps and fans, expressed as a percentage of each unit's rated capacity. Likewise, the change in the unit's heat rate is also expressed as a capacity percentage.

4.6.1 INCREASED PARASITIC USE (FANS AND PUMPS)

Depending on ambient conditions or the operating load at a given time, HGS may be able to take one or more cooling tower cells offline and still obtain the required level of cooling. This would also reduce the cumulative electrical demand from the fans. For the purposes of this study, however, operations are evaluated at the design conditions, i.e., full load; no allowance is made

[7] Increasing the thermal load to the turbine will raise the circulating water temperature exiting the condenser. The cooling towers selected for this study are designed with a maximum water return temperature of approximately 120º F. Depending on each unit's operating conditions (i.e., condenser outlet temperature), the degree to which the thermal input to the turbine can be increased may be limited.

for seasonal changes. The increased electrical demand from cooling tower fan operation is summarized in Table E–18.

Table E–18. Cooling Tower Fan Parasitic Use

	Tower 1
Units served	Unit 5
Generating capacity (MW)	235
Number of fans (one per cell)	5
Motor power per fan (hp)	211
Total motor power (hp)	1,053
MW total	0.78
Fan parasitic use (% of capacity)	**0.33**

Depending on ambient conditions or the operating load at a given time, HGS may be able to take one or more cooling tower cells offline and still obtain the required level of cooling. This would also reduce the cumulative electrical demand from the fans. For the purposes of this study, however, operations are evaluated at the design conditions, i.e., full load; no allowance is made for seasonal changes. The increased electrical demand from cooling tower fan operation is summarized in Table E–18.

Additional circulating water pump capacity for the wet cooling towers will also increase the parasitic electricity usage at HGS. Makeup water will continue to be withdrawn from ILAHC with one of the existing circulating water pumps; the remaining pumps will be retired.

The net increase in pump-related parasitic usage is the difference between the new wet cooling tower configuration (new plus retained pumps) and the existing once-through configuration. For calculation purposes, this study assumes full-load operation to estimate the cost of increased parasitic use.

Because one of the main design assumptions maintains the existing flow rate through each condenser, the new circulating pumps are single speed and are assumed to operate at their full rated capacity when in use. The increased electrical demand associated with cooling tower pump operation is summarized in Table E–19.

Table E–19. Cooling Tower Pump Parasitic Use

	Tower 1
Units served	Unit 5
Generating capacity (MW)	235
Existing pump configuration (hp)	720
New pump configuration (hp)	1,746
Difference (hp)	1,026
Difference (MW)	0.8
Net pump parasitic use (% of capacity)	**0.33%**

4.6.2 HEAT RATE CHANGE

Heat rate adjustments were calculated based on each month's ambient climate conditions and reflect the estimated difference between operations with once-through and wet cooling tower systems. As noted above, the energy penalty analysis assumes HGS will increase its fuel consumption to compensate for lost efficiency and the increased parasitic load from fans and pumps. The higher turbine firing rate will increase the thermal load rejected to the condenser, which, in turn, results in a higher backpressure value and corresponding increase in the heat rate. No data are available describing the changes in turbine backpressures above the design thermal loads. For the purposes of monetizing the energy penalty only, this study conservatively assumed an additional increase in the heat rate of 0.5 percent at the higher firing rate; the actual effect at HGS may be greater or less. Changes in the heat rate for each unit at HGS are presented in Figure E–10.

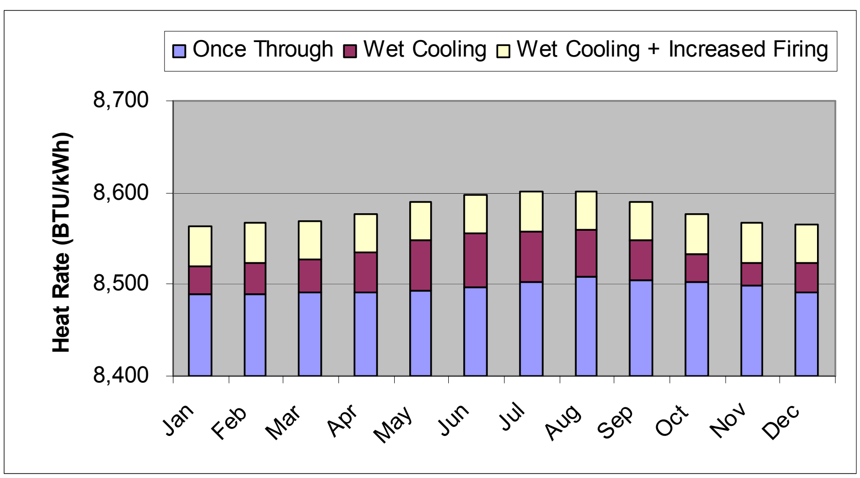

Figure E–10. Estimated Heat Rate Change (Unit 5)

4.6.3 CUMULATIVE ESTIMATE

Using the increased fuel option, the energy penalty's cumulative value is obtained by first calculating the relative costs of generation ($/MWh) for the once-through system and the wet cooling system adjusted for a higher turbine firing rate. The cost of generation for HGS is based on the relative heat rates developed in Section and the average monthly wholesale natural gas cost ($/MMBTU) (ICE 2006a). The difference between these two values represents the monthly increased cost, per MWh, that results from converting to wet cooling towers. This value is then applied to the net MWh generated for the each month and summed to calculate the annual cost.

Based on 2006 output data, the Year 1 energy penalty for HGS will be approximately $100,000. In contrast, the energy penalty's value calculated with the production loss option would be approximately $165,000. Together, these values represent the range of potential energy penalty costs for HGS. Table E–20 summarizes the Year 1 energy penalty estimate for Unit 5 using the increased fuel option.

Table E–20. Unit 5 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	8,490	50.94	8,563	51.38	0.44	15,473	6,754
February	5.50	8,490	46.70	8,566	47.12	0.42	0	0
March	4.75	8,492	40.34	8,570	40.71	0.37	0	0
April	4.75	8,492	40.34	8,577	40.74	0.40	1,325	536
May	4.75	8,493	40.34	8,590	40.80	0.46	17,793	8,223
June	5.00	8,496	42.48	8,598	42.99	0.51	31,925	16,299
July	6.50	8,502	55.26	8,601	55.91	0.64	63,693	40,965
August	6.50	8,507	55.30	8,601	55.91	0.61	29,560	18,059
September	4.75	8,505	40.40	8,590	40.80	0.41	10,146	4,110
October	5.00	8,502	42.51	8,576	42.88	0.37	0	0
November	6.00	8,498	50.99	8,567	51.40	0.41	13,293	5,509
December	6.50	8,492	55.20	8,565	55.67	0.48	128	61
							Unit 5 total	**100,516**

4.7 NET PRESENT COST

The Net Present Cost (NPC) of a wet cooling system retrofit at HGS is the sum of all annual expenditures over the project's 20-year life span discounted according to the year in which the expense is incurred and the selected discount rate. The NPC represents the total change in revenue streams, in 2007 dollars, that HGS can expect over 20 years as a direct result of converting to wet cooling towers. The following values were used to calculate the NPC at a 7 percent discount rate:

- *Capital and Start-up*. Includes all capital, indirect, contingency, and shutdown costs. All costs in this category are incurred in Year 0. (See Table E–16.)
- *Annual O&M*. Base cost values for Year 1 and Year 12 are adjusted for subsequent years using a 2 percent year-over-year escalator. Because HGS has a relatively low capacity utilization factor, O&M costs for the NPC calculation were estimated at 35 percent of their maximum value. (See Table E–17.)
- *Annual Energy Penalty*. Insufficient information is available to this study to forecast future generating output at HGS. In lieu of annual estimates, this study uses the net MWh output from 2006 as the calculation basis for Years 1 through 20. Wholesale prices include a year-over-year price escalator of 5.8 percent (based on the Producer Price Index). The energy penalty values are based on the increased fuel option discussed in Section 4.6. (See Table E–20.)

Using these values, the NPC_{20} for HGS is $28.6 million. Appendix C contains detailed annual calculations used to develop this cost.

4.8 ANNUAL COST

The annual cost incurred by HGS for a wet cooling tower retrofit is the sum of annual amortized capital costs plus the annual average of O&M and energy penalty expenditures. Capital costs are amortized at a 7 percent discount rate over 20 years. O&M and energy penalty costs are calculated in the same manner as for the NPC20 (Section 4.7). Revenue losses from a construction-related shutdown, if any, are incurred in Year 0 only and not included in the annual cost summarized in Table E–21.

Table E–21. Annual Cost

Discount rate	Capital Cost ($)	Annual O&M ($)	Annual energy penalty ($)	Annual cost ($)
7.00%	2,500,000	100,000	200,000	2,800,000

4.9 COST-TO-GROSS REVENUE COMPARISON

Financial data available to conduct a detailed analysis of the economic impact that a wet cooling system retrofit will have on annual revenues for HGS are limited. As a publicly-owned utility, LADWP's gross revenues will include costs for transmission and distribution. An approximation of gross annual revenues was calculated using public data sources (US EIA 2005) that showed LADWP's average annual retail rate was $96/MWh. This rate was applied to the monthly net generating outputs for each unit in 2006 (CEC 2006) to arrive at a facility-wide revenue estimate. This estimate does not reflect seasonal adjustments that may translate to higher or lower per-MWh retail rates through the year, nor does it include other liabilities such as taxes or other operational costs.

The estimated gross revenue for HGS is summarized in Table E–22. A comparison of annual costs to annual gross revenue is summarized in Table E–23.

Table E–22. Estimated Gross Revenue

	Wholesale price ($/MWh)	Net generation (MWh)	Estimated gross revenue ($2007)	
		Unit 5	Unit 5	HGS total
January	96	15,473	1,485,408	**1,485,408**
February	96	0	0	**0**
March	96	0	0	**0**
April	96	1,325	127,200	**127,200**
May	96	17,793	1,708,128	**1,708,128**
June	96	31,925	3,064,800	**3,064,800**
July	96	63,693	6,114,528	**6,114,528**
August	96	29,560	2,837,760	**2,837,760**
September	96	10,146	974,016	**974,016**
October	96	0	0	**0**
November	96	13,293	1,276,128	**1,276,128**
December	96	128	12,288	**12,288**
HGS total		**183,336**	**17,600,256**	**17,600,256**

Table E–23. Cost-Revenue Comparison

Estimated gross annual revenue ($)	Initial capital		O&M		Energy penalty		Total annual cost	
	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross
17,600,000	2,500,000	14.2	100,000	0.6	200,000	1.1	**2,800,000**	**15.9**

5.0 OTHER TECHNOLOGIES

Within the scope of this study, and using the OPC resolution's stated goal of reducing impingement and entrainment by 90–95 percent as a benchmark, the effectiveness of other technologies commonly used to address such impacts could not be conclusively determined for use at HGS. As with many existing facilities, the site's location and configuration complicate the use of some technologies that might be used successfully elsewhere. A more detailed analysis that also comprises a biological evaluation may determine the applicability of one or more of these technologies to HGS. A brief summary of these technologies' applicability follows.

5.1 MODIFIED RISTROPH SCREENS—FINE MESH

The principal concern with this technology is the successful return of viable organisms captured on the screens to the source water body. HGS currently withdraws its cooling water through a conduit at Slip 5 in ILAHC and screens the water for debris at the facility after the water travels approximately 1,100 feet underground. While installing fine-mesh screens and a fish return at the location of the existing screens would not be practical, it is conceivable that this configuration could be installed at the shoreline in Slip 5, assuming there is sufficient space. A detailed evaluation would address the site-specific biology and physical dynamics of the source water to determine whether organisms returned to the water could remain viable and avoid re-impingement on the screens.

5.2 BARRIER NETS

Barrier nets can conceivably be placed in Slip 5. The ILAHC, however, is a major shipping channel, and any location selected for a barrier net is likely to interfere with navigation within the harbor.

5.3 AQUATIC FILTRATION BARRIERS

Aquatic filtration barriers (AFBs) can conceivably be placed in Slip 5, but doing so would restrict access to most of the area. The ILAHC is a major shipping channel, and any location selected for an AFB is likely to interfere with navigation within the harbor.

5.4 VARIABLE SPEED DRIVES

Variable speed drives (VSDs) were not considered for analysis at HGS because the technology alone cannot be expected to achieve the desired level of reductions in impingement and entrainment, nor could it be combined with another technology to yield the desired reductions. Pumps that have been retrofitted with VSDs can reduce overall flow intake volumes by 10 to 50 percent over the current once-through configuration (USEPA 2001). The actual reduction, however, will vary based on the cooling water demand at different times of the year. At peak demand, the pumps will essentially function as standard circulating water pumps and withdraw water at the maximum rated capacity, thus negating any potential benefit. Use of VSDs may be an economically desirable option when pumps are retrofitted or replaced for other reasons, but they were not considered further for this study.

5.5 CYLINDRICAL FINE-MESH WEDGEWIRE

The difficulties surrounding placement of fine-mesh wedgewire screens within ILAHC would appear to preclude their use at HGS. The ILAHC is a major shipping channel, and any location selected for submerged wedgewire screens is likely to interfere with navigation within the harbor.

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Appendix A. Once-Through and Closed-Cycle Thermal Performance

		Unit 5		
		Once through	Closed cycle	Net increase
JAN	Backpressure (in. HgA)	1.63	2.35	**0.71**
	Heat rate Δ (%)	*-0.37*	*0.74*	***1.11***
FEB	Backpressure (in. HgA)	1.63	2.41	**0.78**
	Heat rate Δ (%)	*-0.37*	*0.88*	***1.25***
MAR	Backpressure (in. HgA)	1.72	2.47	**0.75**
	Heat rate Δ (%)	*-0.30*	*1.00*	***1.30***
APR	Backpressure (in. HgA)	1.72	2.59	**0.87**
	Heat rate Δ (%)	*-0.30*	*1.26*	***1.57***
MAY	Backpressure (in. HgA)	1.76	2.81	**1.05**
	Heat rate Δ (%)	*-0.26*	*1.75*	***2.01***
JUN	Backpressure (in. HgA)	1.86	2.95	**1.09**
	Heat rate Δ (%)	*-0.15*	*2.04*	***2.19***
JUL	Backpressure (in. HgA)	2.00	3.00	**1.00**
	Heat rate Δ (%)	*0.08*	*2.15*	***2.07***
AUG	Backpressure (in. HgA)	2.11	3.01	**0.89**
	Heat rate Δ (%)	*0.27*	*2.16*	***1.89***
SEP	Backpressure (in. HgA)	2.06	2.81	**0.75**
	Heat rate Δ (%)	*0.17*	*1.74*	***1.57***
OCT	Backpressure (in. HgA)	2.00	2.57	**0.57**
	Heat rate Δ (%)	*0.08*	*1.23*	***1.15***
NOV	Backpressure (in. HgA)	1.90	2.42	**0.52**
	Heat rate Δ (%)	*-0.08*	*0.90*	***0.98***
DEC	Backpressure (in. HgA)	1.72	2.39	**0.67**
	Heat rate Δ (%)	*-0.30*	*0.83*	***1.13***

Note: Heat rate delta represents change from design value calculated according to estimated ambient conditions for each month.

Appendix B. Itemized Capital Costs

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
CIVIL / STRUCTURAL / PIPING	--	--	--	--	--	--	--	--	--	--
Allocation for other accessories (bends, water hammers…)	lot	1	--	--	500,000	500,000	4,000.00	85	340,000	**840,000**
Allocation for pipe racks (approx 400 ft) and cable racks	t	40	--	--	2,500	100,000	17.00	105	71,400	**171,400**
Allocation for sheet piling and dewatering	lot	1	--	--	500,000	500,000	5,000.00	100	500,000	**1,000,000**
Allocation for testing pipes	lot	1	--	--	--	--	2,000.00	95	190,000	**190,000**
Allocation for Tie-Ins to existing condenser's piping	lot	1	--	--	250,000	250,000	2,000.00	85	170,000	**420,000**
Allocation for trust blocks	lot	1	--	--	50,000	50,000	500.00	95	47,500	**97,500**
Backfill for PCCP pipe (reusing excavated material)	m3	891	--	--	--	--	0.04	200	7,128	**7,128**
Bedding for PCCP pipe	m3	320	--	--	25	8,000	0.04	200	2,560	**10,560**
Bend for PCCP pipe 16" diam (allocation)	ea	7	--	--	3,000	21,000	20.00	95	13,300	**34,300**
Bend for PCCP pipe 72" diam (allocation)	ea	3	--	--	18,000	54,000	40.00	95	11,400	**65,400**
Building architectural (siding, roofing, doors, painting…etc)	ea	1	--	--	57,500	57,500	690.00	75	51,750	**109,250**
Butterfly valves 30" c/w allocation for actuator & air lines	ea	7	30,800	215,600	--	--	50.00	85	29,750	**245,350**
Butterfly valves 48" c/w allocation for actuator & air lines	ea	4	46,200	184,800	--	--	50.00	85	17,000	**201,800**
Butterfly valves 54" c/w allocation for actuator & air lines	ea	8	60,900	487,200	--	--	55.00	85	37,400	**524,600**
Check valves 48"	ea	2	66,000	132,000	--	--	24.00	85	4,080	**136,080**
Concrete basin walls (all in)	m3	125	--	--	225	28,125	8.00	75	75,000	**103,125**
Concrete elevated slabs (all in)	m3	145	--	--	250	36,250	10.00	75	108,750	**145,000**
Concrete for transformers and oil catch basin (allocation)	m3	200	--	--	250	50,000	10.00	75	150,000	**200,000**
Concrete slabs on grade (all in)	m3	557	--	--	200	111,400	4.00	75	167,100	**278,500**
Ductile iron cement pipe 12" diam. for fire water line	ft	700	--	--	100	70,000	0.60	95	39,900	**109,900**
Excavation and backfill for fire line & make-up (using excavated material for backfill except for bedding)	m3	2,388	--	--	--	--	0.08	200	38,208	**38,208**
Excavation for PCCP pipe	m3	1,336	--	--	--	--	0.04	200	10,688	**10,688**
Fencing around transformers	m	50	--	--	30	1,500	1.00	75	3,750	**5,250**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Flange for PCCP joints 30"	ea	5	--	--	2,260	11,300	16.00	95	7,600	**18,900**
Foundations for pipe racks and cable racks	m3	95	--	--	250	23,750	8.00	75	57,000	**80,750**
FRP flange 30"	ea	19	--	--	1,679	31,904	50.00	85	80,750	**112,654**
FRP flange 48"	ea	12	--	--	3,000	36,000	75.00	85	76,500	**112,500**
FRP flange 54"	ea	14	--	--	5,835	81,689	80.00	85	95,200	**176,889**
FRP pipe 48" diam.	ft	220	--	--	331	72,842	0.70	85	13,090	**85,932**
FRP pipe 54" diam.	ft	850	--	--	426	361,845	0.80	85	57,800	**419,645**
Harness clamp 16" c/w external testable joint	ea	40	--	--	1,715	68,600	14.00	95	53,200	**121,800**
Harness clamp 72" c/w internal testable joint	ea	20	--	--	2,440	48,800	18.00	95	34,200	**83,000**
Joint for FRP PIPE 48" diam.	ea	10	--	--	1,300	13,000	75.00	85	63,750	**76,750**
Joint for FRP pipe 54" diam.	ea	30	--	--	1,324	39,732	85.00	85	216,750	**256,482**
PCCP pipe 16" dia. For make-up	ft	700	--	--	98	68,600	0.50	95	33,250	**101,850**
PCCP pipe 72" diam.	ft	300	--	--	507	152,100	1.30	95	37,050	**189,150**
Riser (FRP pipe 30" diam X 40 ft)	ea	5	--	--	14,603	73,015	100.00	85	42,500	**115,515**
Structural steel for building	t	80	--	--	2,500	200,000	20.00	105	168,000	**368,000**
CIVIL / STRUCTURAL / PIPING TOTAL	**--**	**--**	**--**	**1,019,600**	**--**	**3,120,952**	**--**	**--**	**3,123,304**	**7,263,856**
ELECTRICAL	--	--	--	--	--	--	--	--	--	**--**
4.16 kv cabling feeding MCC's	m	1,000	--	--	75	75,000	0.40	85	34,000	**109,000**
4.16kV switchgear - 4 breakers	ea	1	250,000	250,000	--	--	150.00	85	12,750	**262,750**
460 volt cabling feeding MCC's	m	500	--	--	70	35,000	0.40	85	17,000	**52,000**
480V Switchgear - 1 breaker 3000A	ea	4	30,000	120,000	--	--	80.00	85	27,200	**147,200**
Allocation for automation and control	lot	1	--	--	500,000	500,000	5,000.00	85	425,000	**925,000**
Allocation for cable trays and duct banks	m	600	--	--	75	45,000	1.00	85	51,000	**96,000**
Allocation for lighting and lightning protection	lot	1	--	--	75,000	75,000	750.00	85	63,750	**138,750**
Dry Transformer 2MVA xxkV-480V	ea	4	100,000	400,000	--	--	100.00	85	34,000	**434,000**
Lighting & electrical services for pump house building	ea	1	--	--	50,000	50,000	1,000.00	85	85,000	**135,000**
Local feeder for 1000 HP motor 4160 V (up to MCC)	ea	2	--	--	40,000	80,000	150.00	85	25,500	**105,500**
Local feeder for 200 HP motor 460 V (up to MCC)	ea	5	--	--	18,000	90,000	150.00	85	63,750	**153,750**
Oil Transformer 10/13.33MVA xx-4.16kV	ea	2	190,000	380,000	--	--	150.00	85	25,500	**405,500**
Primary breaker(xxkV)	ea	4	45,000	180,000	--	--	60.00	85	20,400	**200,400**
Primary feed cabling (assumed 13.8 kv)	m	3,000	--	--	175	525,000	0.50	85	127,500	**652,500**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
ELECTRICAL TOTAL	--	--	--	**1,330,000**	--	**1,475,000**	--	--	**1,012,350**	**3,817,350**
MECHANICAL	--	--	--	--	--	--	--	--	--	--
Allocation for ventilation of buildings	ea	1	25,000	25,000	--	--	250.00	85	21,250	**46,250**
Cooling tower for units 1,2 and 5	lot	1	2,600,000	2,600,000	--	--	--	--	--	**2,600,000**
Overhead crane 50 ton in (in pump house) Including additional structure to reduce the span	ea	1	500,000	500,000	--	--	1,000.00	85	85,000	**585,000**
Pump 4160 V 1000 HP	ea	2	800,000	1,600,000	--	--	420.00	85	71,400	**1,671,400**
MECHANICAL TOTAL	--	--	--	**4,725,000**	--	**0**	--	--	**177,650**	**4,902,650**

Appendix C. Net Present Cost Calculation

Project year	Capital/start-up ($)	O & M ($)	Energy penalty	Total ($)	Annual discount factor	Present value ($)
			Unit 5			
0	26,000,000	--	--	26,000,000	1	**26,000,000**
1	--	67,680	100,516	168,196	0.9346	**157,196**
2	--	69,034	106,376	175,409	0.8734	**153,203**
3	--	70,414	112,577	182,992	0.8163	**149,376**
4	--	71,823	119,141	190,963	0.7629	**145,686**
5	--	73,259	126,087	199,346	0.713	**142,133**
6	--	74,724	133,438	208,162	0.6663	**138,698**
7	--	76,219	141,217	217,436	0.6227	**135,397**
8	--	77,743	149,450	227,193	0.582	**132,226**
9	--	79,298	158,163	237,461	0.5439	**129,155**
10	--	80,884	167,384	248,268	0.5083	**126,194**
11	--	82,502	177,142	259,644	0.4751	**123,357**
12	--	100,099	187,470	287,568	0.444	**127,680**
13	--	102,101	198,399	300,500	0.415	**124,707**
14	--	104,143	209,966	314,108	0.3878	**121,811**
15	--	106,226	222,207	328,432	0.3624	**119,024**
16	--	108,350	235,161	343,511	0.3387	**116,347**
17	--	110,517	248,871	359,388	0.3166	**113,782**
18	--	112,727	263,380	376,108	0.2959	**111,290**
19	--	114,982	278,735	393,717	0.2765	**108,863**
20	--	117,282	294,986	412,267	0.2584	**106,530**
Total						**28,582,655**

F. HAYNES GENERATING STATION

LOS ANGELES DEPT. OF WATER AND POWER—LONG BEACH, CA

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Appendices

1.0 GENERAL SUMMARY

Retrofitting the existing once-through cooling system at Haynes Generating Station (HnGS) with closed-cycle wet cooling towers is technically and logistically feasible based on this study's design criteria, and will reduce cooling water withdrawals from Alamitos Bay by approximately 95 percent. Impingement and entrainment impacts would be reduced by a similar proportion.

The preferred option selected for HnGS includes 3 conventional wet cooling towers (without plume abatement), with individual cells arranged in an inline configuration to accommodate limited space at the site. The site configuration results in towers placed at substantial distances from their respective units. Local land use requirements and public health ordinances place further constraints on the different wet cooling tower designs that can be considered at HnGS, but do not appear to preclude their installation at the site. If required, plume-abated towers could be configured at the site, but would require a greater area and would increase costs by factor or 2 or 3.

Construction-related shutdowns are estimated to take approximately 6 weeks per unit (concurrent). HnGS is expected to incur a financial loss as a result based on 2006 capacity utilization rates for Unit 8.

The cooling tower configuration designed under the preferred option complies with all identified local use restrictions and includes necessary mitigation measures, where applicable.

1.1 COSTS

Because Unit 8 is substantially newer than the other generating units at HnGS and is likely to operate at a higher utilization rate, it is conceivable that a wet cooling system retrofit would be applied to Unit 8 only instead of all five active units. Accordingly, some aspects of the cost analysis are presented for the facility as a whole and for Unit 8 alone, i.e., as though Unit 8 operated as an independent facility.

Initial capital and net present costs associated with the installation and operation of wet cooling towers at HnGS are summarized in Table F–1. Annualized costs based on 20-year average values for the various cost elements are summarized in Table F–2.

Table F–1. Cumulative Cost Summary

HnGS (all units)				HnGS (Unit 8 only)			
Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)	Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Total capital and start-up [a]	152,000,000	10.72	43.54	Total capital and start-up [a]	42,400,000	8.42	12
NPC_{20} [2]	208,900,000	14.73	59.83	NPC_{20} [b]	65,500,000	13.01	19

[1] Includes all costs associated with the construction and installation of cooling towers and shutdown loss, if any.
[2] NPC_{20} includes all capital costs, operation and maintenance costs, and energy penalty costs over 20 years discounted at 7 percent.

Table F–2. Annual Cost Summary

HnGS (all units)				HnGS (Unit 8 only)			
Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)	Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Capital and start-up [a]	14,300,000	1.01	4.10	Capital and start-up [a]	4,000,000	0.79	1.15
Operations and maintenance	1,900,000	0.13	0.54	Operations and maintenance	600,000	0.12	0.17
Energy penalty	3,600,000	0.25	1.03	Energy penalty	1,400,000	0.28	0.40
Total HnGS annual cost	**19,800,000**	**1.39**	**5.67**	**Unit 8 only annual cost**	**6,000,000**	**1.19**	**1.72**

[a] Does not include revenue loss associated with shutdown, which is incurred in Year 0 only. Shutdown loss forecast for HnGS equals $5.1 million. Shutdown cost is associated with Unit 8 only.

1.2 ENVIRONMENTAL

Environmental changes associated with a cooling tower retrofit for HnGS are summarized in Table F–3 and discussed further in Section 3.4.

Table F–3. Environmental Summary

		Units 1 & 2	Units 5 & 6	Unit 8
Water use	Design intake volume (gpm)	177,800	272,000	146,000
	Cooling tower makeup water (gpm)	8,400	11,400	5,400
	Reduction from capacity (%)	95	96	96
Energy efficiency [a]	Summer heat rate increase (%)	1.24	1.37	0.56
	Summer energy penalty (%)	2.20	2.39	0.94
	Annual heat rate increase (%)	1.04	1.13	0.45
	Annual energy penalty (%)	1.99	2.16	0.83
Direct air emissions [b]	PM_{10} emissions (tons/yr) (maximum capacity)	102	156	84
	PM_{10} emissions (tons/yr) (2006 capacity utilization)	13	11	34

[a] Reflects the comparative increase between once-through and wet cooling systems, but does not account for any operational changes to address the change in efficiency, such as increased fuel consumption (see Section 4.6).
[b] Reflects emissions from the cooling tower only; does not include any increase in stack emissions.

1.3 OTHER POTENTIAL FACTORS

Considerations outside this study's scope may limit the practicality or overall feasibility of a wet cooling tower retrofit at Haynes.

HnGS may also face wastewater discharge permit conflicts upon converting to wet cooling towers. The current source water (Alamitos Bay) has shown elevated concentrations of some pollutants that would become concentrated in a wet cooling tower. If cooling tower makeup water is obtained from the same source, compliance with effluent limitations may become more difficult. In addition, the facility's receiving water has been reclassified from an ocean to an estuary, which may result in more stringent limitations than those currently applicable. These potential conflicts may be mitigated or eliminated through the use of reclaimed water as the makeup source.

During the recent Unit 8 repowering project, objections were raised from nearby residential communities (Leisure World) regarding noise and visual impacts. It is likely that these same objections would be raised against a wet cooling tower installation. Any restrictions that result from those objections can only be quantified as part of the public involvement process that is beyond this study's scope. To the extent practical, this study has included mitigation measures to reduce noise impacts to a level deemed acceptable by the local noise control officer.

The only potential challenge to siting a wet cooling tower at HnGS appears to be the availability of the area selected for the installation and potential uses of the site. Discussions with facility staff indicate the area may be reserved for future projects, although the scope of those projects is unknown.[1] Barring use of the selected area, placement of wet cooling towers would become more problematic, as existing structures and facilities would have to be reconfigured to accommodate the selected design.

[1] Following the Administrative Draft's publication, the Los Angeles Department of Water and Power Board of Commissioners adopted the *Integrated Resource Plan,* which approves a repowering project sited in the same location as identified for wet cooling tower placement in this study (LADWP 2007).

2.0 BACKGROUND

The Haynes Generating Station is a natural gas–fired steam electric generating facility located in the city of Long Beach, Los Angeles County, owned and operated by the City of Los Angeles Department of Water and Power (LADWP). Originally purchased by LADWP as a replacement for the Seal Beach Generating Station in 1957, HnGS currently operates four conventional steam generating units (Unit 1, Unit 2, Unit 5, and Unit 6) and one combined-cycle unit (Unit 8) that utilizes a heat recovery steam generator (HRSG) to capture waste heat generated by two gas combustion turbine units to power a steam turbine.[2] (See Table F–4.)

The facility is located on 122 acres in the city of Long Beach (a small portion resides within the city of Seal Beach) approximately 2 miles northeast of the entrance to Alamitos Bay (Figure F–1). The property parallels the east bank of the San Gabriel River for 3/4 mile north of Westminster Avenue to State Highway 22. The eastern edge of the property is bounded by the Orange County Flood Control District Channel. The Alamitos Generating Station lies opposite HnGS on the west bank of the San Gabriel River.

Table F–4. General Information

Unit	In-service year	Rated capacity (MW)	2006 capacity utilization [a] (%)	Condenser cooling water flow (gpm)
Unit 1	1962	222	13.1	88,900
Unit 2	1963	222	13.1	88,900
Unit 5	1966	322	7.31	136,000
Unit 6	1967	322	7.31	136,000
Unit 8	2005	575 [b]	41.0 [c]	146,000
HnGS total		**1,663**	**24.6**	**595,800**

[a] Unit-level data unavailable for 2006. Capacity utilization rates based on 2005 Quarterly Fuel and Energy Report and assumed to be the same for 2006 (CEC 2005).
[b] Includes gas combustion turbines (2 x 170 MW) and steam turbine (235 MW).
[c] Output data unavailable for Unit 8. Estimate based on the increase in total facility output from 2005 to 2006 (CEC 2006).

[2] Documents occasionally identify the components of the combined-cycle unit independently: Unit 8 (steam turbine) and units 9 and 10 (gas turbines). Because the advantage of a combined-cycle system is only obtained when the units function together, reference to “Unit 8” at HnGS in this study is taken to mean the combined-cycle unit as a whole.

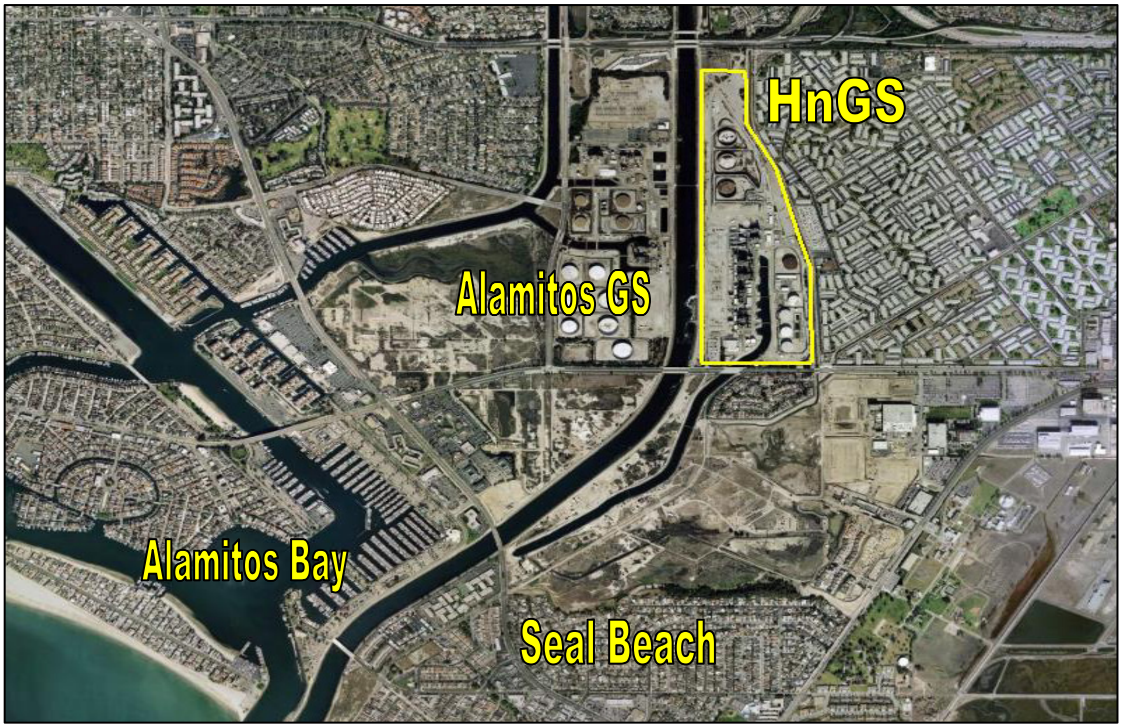

Figure F–1. General Vicinity of Haynes Generating Station

2.1 COOLING WATER SYSTEM

HnGS operates one cooling water intake structure (CWIS) to provide condenser cooling water to each of the five generating units (Figure F–2).[3] Water is withdrawn from Alamitos Bay through seven openings in a bulkhead wall in the northeast corner of the Long Beach Marina. Seven 8-foot diameter pipes (only six are typically used) lead under the San Gabriel River to a manmade canal extending 1.5 miles northeast to the station, where six separate screenhouses (one for each unit) draw water from the canal (Figure F–3). Once-through cooling water is combined with low-volume wastes generated by HnGS and discharged through one of six outfalls to the San Gabriel River. Surface water withdrawals and discharges are regulated by NPDES Permit CA0000353, as implemented by Los Angeles Regional Water Quality Control Board (LARWQCB) Order 00-081 (revised by Order R4-2004-0089).[4]

[3] The definition of a CWIS is taken from 40 CFR 125.93, which defines a CWIS as “the total physical structure and any associated constructed waterways used to withdraw cooling water from waters of the U.S. The cooling water intake structure extends from the point at which water is withdrawn from the surface water source up to, and including, the intake pumps.” Past definitions of CWIS have often centered on the number of intake bays.

[4] LARWQCB Order 00-081 expired on May 10, 2005, but has been administratively extended pending adoption of a renewed order.

Figure F-2. Site View

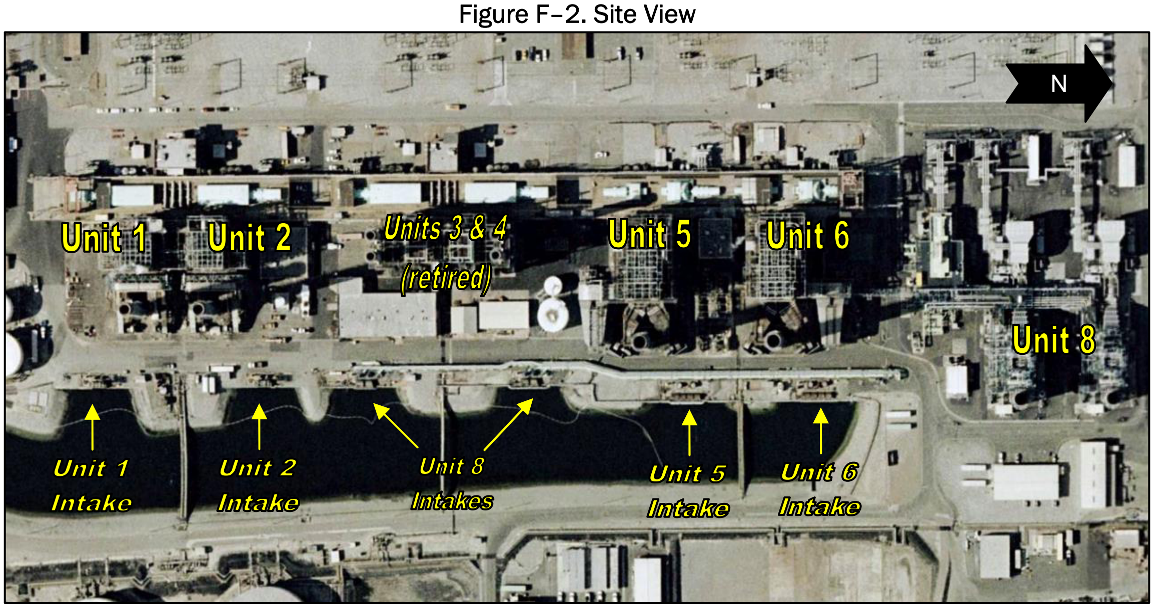

Figure F-3. Intake Locations

The screenhouses for Units 1 and 2 are identical, with each containing two screen bays fitted with stationary screens. Each screen is 10 feet wide with 3/8-inch wire mesh panels. Velocities at the screens are reported to be 0.9 feet per second (fps). Downstream of each screen is a circulating water pump rated at 48,000 gallons per minute (gpm), for a total capacity of 192,000 gpm, or 276 million gallons per day (mgd) (LADWP 2005).

The screenhouses for Units 5 and 6 are identical, with each consisting of four screen bays fitted with vertical traveling screens. Each screen is 8 feet wide with 3/8-inch wire mesh panels.

Velocities at the screens are reported to be 0.8 feet per second (fps). Screens are normally rotated and cleaned once every 8 hours. A high-pressure spray removes any debris from the screens, including impinged fish, for disposal at a landfill. Two circulating water pumps for each unit are located downstream of the screens, with a design rating of 80,000 gpm, for a total capacity of 320,000 gpm, or 461 mgd (LADWP 2005).

Unit 8 utilizes the two screenhouses previously used by Unit 3 and Unit 4. Each screenhouse consists of two screen bays. Each screen is 10 feet wide with 3/8-inch wire mesh panels. Velocities at the screens are reported to be 0.7 feet per second (fps). Screens are normally rotated and cleaned once every 8 hours. A high-pressure spray removes any debris from the screens, including impinged fish, for disposal at a landfill. Two circulating water pumps for each unit are located downstream of the screens, with a design rating of 40,000 gpm for a total capacity of 160,000 gpm, or 230 mgd (LADWP 2005).

At maximum capacity, HnGS maintains a total pumping capacity rated at 968 mgd, with a total condenser flow rating of 858 mgd. On an annual basis, HnGS withdraws substantially less than its design capacity due to its low generating capacity utilization (24.6 percent for 2006). On a daily basis during peak demand periods, however, intake flows may approach the design intake rate. When in operation and generating the maximum load, HnGS can be expected to withdraw water from Alamitos Bay at a rate approaching its maximum capacity.

2.2 SECTION 316(B) PERMIT COMPLIANCE

The CWIS currently in operation at HnGS does not currently utilize technologies generally considered to be effective at reducing impingement mortality and/or entrainment. LARWQCB Order 00-081 references an ecological study conducted by HnGS to determine whether the CWIS was compliant with Section 316(b) of the Clean Water Act (date unknown). Finding 17 of the order, adopted in 2000, notes:

> …the study addressed the important ecological and engineering factors specified in the guidelines, demonstrated that the ecological impacts of the intake system are environmentally acceptable, and provided evidence that no modifications to design, location, or capacity of the intake structure are required. (LARWQCB 2000, Finding 17)

The order does not contain any numeric or narrative limitations regarding impingement or entrainment resulting from CWIS operation, but does require semiannual monitoring of impingement at the intake structure (coinciding with scheduled heat treatments). Based on the record available for review, HnGS has been compliant with this permit requirement.

In 2004, the LADWP filed notice to modify its existing order to reflect changes to the facility resulting from the retiring of Unit 3 and Unit 4 and the incorporation of the combined-cycle unit (Unit 8). The revised order (R4-2004-0089) did not alter effluent limitations or monitoring requirements but did include a finding stating that EPA had promulgated a new rule implementing Section 316(b) and would potentially require additional compliance measures upon renewal of the permit (LARWQCB 2004, Finding 11).

3.0 WET COOLING SYSTEM RETROFIT

3.1 OVERVIEW

This study evaluates the use of saltwater wet cooling towers at HnGS, with the current source water (Alamitos Bay) continuing to provide makeup water to the facility. Conversion of the existing once-through cooling system to wet cooling towers will reduce the facility's current intake capacity by approximately 96 percent; rates of impingement and entrainment will decline by a similar proportion. Use of reclaimed water was considered for HnGS but not analyzed in detail because the available volume cannot serve as a replacement for once-through cooling water. As a makeup water source, reclaimed water may be an attractive alternative when considering additional benefits its use may provide, such as avoidance of conflicts with effluent limitations or air emission standards. Reclaimed water is discussed further in Section 3.4.4, below.

The configuration of the wet cooling towers—their size and location—were based on best professional judgment (BPJ) using the criteria outlined in Chapter 5 and designed to meet the performance benchmarks in the most cost-effective manner. Information not available to this study that offers a more complete characterization of the facility may lead to different conclusions regarding the physical configuration of the towers.

Based on a review of information provided by LADWP and obtained from public records, installation of wet cooling towers is a logistically feasible option at HnGS, provided the areas identified below are available for use. The overall configuration of HnGS and the relative location of available space limit the configuration of the selected design only insofar as some units are located at a substantial distance from their respective cooling towers. This study developed a conceptual design of wet cooling towers sufficient to meet the cooling demand for each active generating unit at HnGS at its rated output during peak climate conditions. Cost estimates are based on vendor quotes developed using the available information and the various design constraints identified at the HnGS.

The overall practicality of retrofitting the five units at HnGS, from a cost perspective, will require an evaluation of factors outside the scope of this study, such as the age and efficiency of the units and their role in the overall reliability of electricity production and transmission in California, particularly the Los Angeles region.

3.2 DESIGN BASIS

3.2.1 CONDENSER SPECIFICATIONS

For this study, the conceptual design of the cooling towers selected for HnGS is based on the assumption that the condenser flow rate and thermal load to each will remain unchanged from the current system. Although no provision is included to re-optimize the condenser performance for service with a cooling tower, some modifications to the condenser (tube sheet and water box reinforcement) may be necessary to handle the increased water pressures that will result from the increased total pump head required to raise water to the elevation of the cooling tower risers.[5] The practicality and difficulty of these modifications are dependent on the age and configuration of each unit, but are assumed to be feasible at HnGS. Condenser water boxes for all six units are located at grade level and appear to be readily accessible. Additional costs associated with condenser modifications are included in the discussion of capital expenditures (Section 4.3).

Information provided by HnGS was largely used as the basis for the cooling tower design. In some cases, the data contained on condenser specification sheets was internally inconsistent or insufficiently explained. Where possible, questionable values were verified or corrected using other known information about the condenser. Parameters used in the development of the cooling tower design are summarized in Table F–5. Units grouped together are mirror images of each other and generally share identical design specifications.

Table F–5. Condenser Design Specifications

	Units 1 & 2	Units 5 & 6	Unit 8
Thermal load (MMBTU/hr)	860	1,177.2	1,104.1
Surface area (ft2)	95,000	136,000	87,600
Condenser flow rate (gpm)	88,900	136,000	146,000
Tube material	Al Brass	Cu-Ni (70-30)	Titanium
Heat transfer coefficient (Ud)	498	443	591
Cleanliness factor	0.85	0.85	0.85
Inlet temperature (°F)	62	62	63
Temperature rise (°F)	19.36	17.32	15.13
Steam condensate temperature (°F)	91.7	91.7	92.9

3.2.2 AMBIENT ENVIRONMENTAL CONDITIONS

HnGS is located in Long Beach, Los Angeles County, approximately 2 miles inland from the entrance to Alamitos Bay, where cooling water is withdrawn from the Long Beach Marina near the surface. Tidal influences and the operation of the HnGS circulating water pumps draw ocean water through the marina to the CWIS. Inlet water temperatures are expected to be comparable to temperatures within the marina. Data provided by HnGS detailing monthly inlet temperatures contained gaps for some months when units were not operational. Surface water temperatures used in this analysis were supplemented with monthly average coastal water temperatures as reported in the NOAA *National Oceanographic Data Center—Coastal Water Temperature* Guide, Los Angeles (NOAA 2007).

The wet bulb temperature used in the development of the overall cooling tower design was obtained from American Society of Heating, Refrigerating and Air-Conditioning Engineers

[5] In this context, re-optimization refers to a comprehensive condenser overhaul that reduces thermal efficiency losses associated with a wet cooling tower's higher circulating water temperatures. Modifications discussed in this study are generally limited to reinforcement measures that enable the condenser to withstand increased water pressures.

(ASHRAE) publications. Data for the Long Beach area indicate a 1 percent ambient wet bulb temperature of 71° F (ASHRAE 2006). An approach temperature of 10° F was selected based on the site configuration and vendor input.[6] At the design wet bulb and approach temperatures, the cooling towers will yield "cold" water at a temperature of 81° F. Monthly maximum wet bulb temperatures used in the development of energy penalty estimates in Section 4.6 were calculated using data obtained from California Irrigation Management Information System (CIMIS) Monitoring Station 174 in Long Beach (CIMIS 2006). Climate data used in this analysis are summarized in Table F–6.

Table F–6. Surface Water and Ambient Wet Bulb Temperatures

	Surface (°F)	Ambient wet bulb (°F)
January	58.2	54.0
February	59.8	56.0
March	62.0	58.0
April	64.5	63.0
May	66.8	66.0
June	68.2	68.0
July	69.3	71.0
August	70.0	71.0
September	68.2	69.0
October	64.5	64.0
November	61.6	58.0
December	58.0	54.0

3.2.3 LOCAL USE RESTRICTIONS

3.2.3.1 NOISE

HnGS is located in Noise District 4, according to the City of Long Beach Health and Safety Code. This area is considered an "industrial sanctuary" within the city, although commercial and residential zoning areas are located in close proximity to the site, with some residences no more than 300 feet from the property line. The limit for continual noise in District 4 is 70 dBA. Limits for this district are generally applied at the nearest point of likely nuisance, such as a nearby residential or public recreation area. Residential areas to the northeast in Seal Beach (Leisure World) are the most likely to be adversely affected by any elevated noise levels. Discussions with the noise control officer for the city of Long Beach indicated that despite the current noise district designation for HnGS, new development in the area would likely be required to meet the daytime noise requirements for District 1 of the code (50 dBA compared with 70 dBA) (Long Beach 2006).

[6] An approach temperature of 12° F was selected for most facilities in this study. A 10° F approach was used for HnGS based on the input from a different vendor (SPX Cooling, Inc.). Cooling towers designed to a 10° F approach will be slightly larger in size and may require additional fan and pump power, thus increasing initial capital costs and parasitic energy usage. Costs are partially offset by a lower circulating water temperature, which mitigates the energy penalty effect. Based on information from cooling tower vendors, the lower approach temperature results in a tower that is approximately 10 to 12 percent larger than a comparable tower designed for a 12° F approach temperature.

The overall design of the wet cooling tower installation for HnGS incorporates noise control measures to meet local zoning restrictions. Low-noise fans and fan deck barrier walls are included to buffer noise associated with mechanical operation of the towers. In addition, concrete barrier walls will be constructed to minimize the noise associated with water falling through the tower. Barrier walls will be placed between the tower and the potentially affected areas and built to a height of 16 feet.

3.2.3.2 BUILDING HEIGHT

HnGS is located within a planned industrial development zone (Southeast Development and Improvement Plan [SEADIP]) within the city of Long Beach. Within this zone, structures are limited to a maximum above-grade height of 65 feet (Long Beach 2007). The height of the wet cooling towers designed for HnGS, from grade level to the top of the fan deck barrier walls, is 45 feet.

3.2.3.3 PLUME ABATEMENT

Local zoning ordinances do not contain any specific criteria for addressing any impact associated with a wet cooling tower plume. Using the selection criteria for this study, plume abatement measures were not considered for HnGS; all towers are of a conventional design. The plume from wet cooling towers at HnGS is not expected to adversely impact nearby infrastructure; the nearest area of immediate concern is the San Diego Freeway (I-405), located approximately 3/4 mile to the northeast.

Community standards for assessing the visual impact associated with a cooling tower plume cannot be determined within the scope of this study. The proximity of nearby residential and commercial areas, when viewed in the context of CEC siting guidelines, may contribute to the selection of an alternate design if a wet cooling tower retrofit is undertaken at HnGS in the future. These guidelines assess the total size and persistence of a visual plume with respect to aesthetic standards for coastal resources. Significant visual changes resulting from the plume may warrant incorporation of plume abatement measures. The selection of plume-abated cooling towers, however, may add to the difficulty of identifying sufficient areas in which to locate such towers at HnGS. The additional height required for plume-abated towers (approximately 15–30 feet) may conflict with height restrictions under local zoning ordinances (Section 3.2.3.2), depending on the final design configuration.

3.2.3.4 DRIFT AND PARTICULATE EMISSIONS

Drift elimination measures that are considered best available control technology (BACT) are required for all cooling towers evaluated in this study regardless of their location. State-of-the-art drift eliminators are included for each cooling tower cell at HnGS, with an accepted efficiency of 0.0005 percent. Because cooling tower PM_{10} emissions are a function of the rate of drift, drift eliminators are also considered BACT for PM_{10} emissions from wet cooling towers. This efficiency can be verified by a proper in situ test, which accounts for site-specific climate, water, and operating conditions. Testing based on the Isokinetic Drift Test Code published by the Cooling Tower Institute is only required at initial start-up on one representative cell of each tower for an approximate cost of $60,000 per test, or approximately $180,000 for all three of the cooling towers at HnGS (CTI 1994). This cost is not itemized in the final analysis and is instead included as part of the indirect cost estimate (Section 4.3).

3.2.3.5 FACILITY CONFIGURATION AND AREA CONSTRAINTS

The configuration of the HnGS site and relative locations of the five generating units creates several challenges in selecting a location for wet cooling towers at the facility. As shown in Figure F–4, the switchyard currently occupies the optimal location for cooling towers, which would limit the distance between the condensers and each tower. This study, however, did not consider relocating the switchyard due to the complexity and cost of such a project. Area 1, located on the southeastern edge of the property, is currently occupied by active fuel tanks and cannot be removed or relocated without significant disruption and cost.

Area 2 is currently occupied by three large fuel tanks (300-foot diameter) that have been decommissioned and are slated for removal in the near future. Area 2, upon removal of the tanks, is the most logical option for cooling tower placement. It is noted, however, that discussions with LADWP staff have identified the possibility that much of this area has been reserved for future repower projects, although details of the total size of the project and area dedicated to it were not available for evaluation. This study assumed a portion of Area 2 would be available for cooling tower placement.

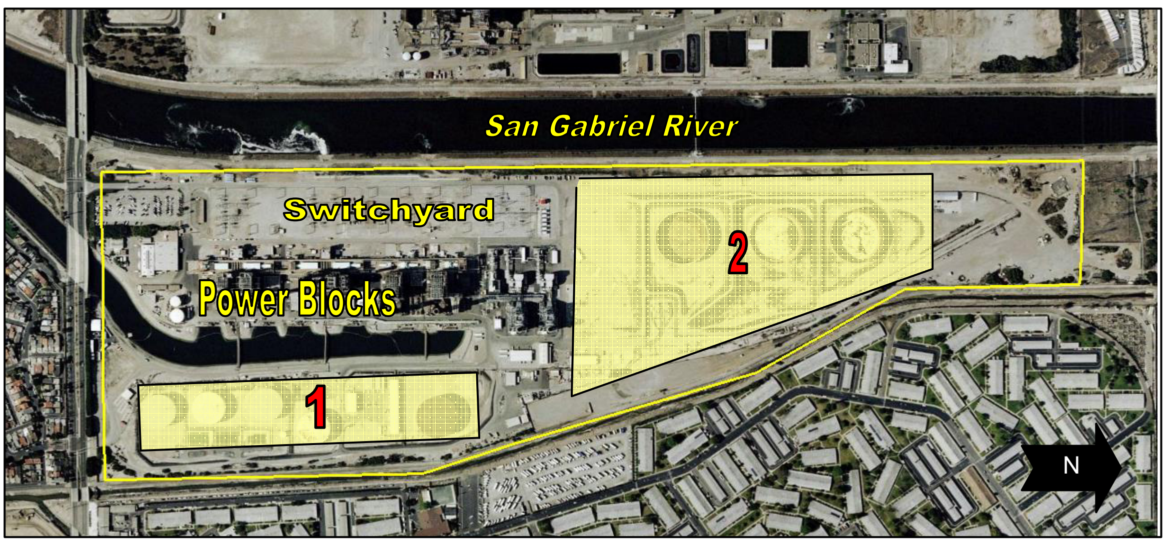

Figure F–4. Cooling Tower Siting Locations

3.3 CONCEPTUAL DESIGN

Based on the design constraints discussed above, three separate wet cooling towers were selected to replace the current once-through cooling systems at HnGS. Each tower will operate independently and be dedicated to each unit or unit pair: Units 1 and 2; Unit 3 and Unit 4; and Unit 8. The age, efficiency, and design of the unit pairs are essentially identical and often operate in tandem; thus, a single cooling tower to serve both units is a practical option that minimizes the required space and reduces some material costs for required pump capacity. Each tower is configured in a multicell, inline arrangement.

3.3.1 SIZE

Each tower is constructed over a concrete collection basin 4 feet deep. The basin is larger than the footprint of the tower structure, extending an additional 2 feet in each direction. The concrete used for construction is suitable for saltwater applications. The principal tower material is fiber reinforced plastic (FRP), with stainless steel fittings. These materials are more resistant to the higher corrosive effects of saltwater.

The size of each tower is primarily based on the cumulative thermal load rejected to the tower by the surface condenser(s) and a 10° F approach to the ambient wet bulb temperature. Flow rates through each condenser remain unchanged.

General characteristics of the wet cooling towers selected for HnGS are summarized in Table F–7.

Table F–7. Wet Cooling Tower Design

	Tower 1 (Units 1 & 2)	Tower 2 (Units 5 & 6)	Tower 3 (Unit 8)
Thermal load (MMBTU/hr)	1,720	2,354	1,104
Circulating flow (gpm)	177,800	272,000	146,000
Number of cells	13	18	10
Tower type	Mechanical draft	Mechanical draft	Mechanical draft
Flow orientation	Counterflow	Counterflow	Counterflow
Fill type	Film	Film	Film
Arrangement	Inline	Inline	Inline
Primary tower material	FRP	FRP	FRP
Tower dimensions (l x w x h) (ft)	703 x 54 x 45	972 x 54 x 45	540 x 54 x 45
Tower footprint with basin (l x w) (ft)	707 x 58	976 x 58	544 x 58

3.3.2 LOCATION

The initial site selection for each tower was based on the desire to locate each tower as close as possible to its respective generating unit in order to minimize the supply and return pipe distances and the required pumping capacity. The configuration of HnGS requires placement of all three towers in the northern section of the site. For Units 1 and 2, this location results in long supply and return pipe distances (approximately 2,000 feet in each direction) to Tower 2. Tower 1, which serves Units 5 and 6, is located at an approximate distance of 1,000 feet, with Unit 8 less than 500 feet from Tower 3.

Figure F–5 identifies the approximate location of all three towers and supply and return piping. A 16-foot-high concrete barrier wall (not shown) will be constructed on the north, east, and south sides of each tower to reduce the noise associated with falling water and enable compliance with local noise ordinances. Barrier walls will not be required on the west side due to the low potential for noise impacts in that direction.

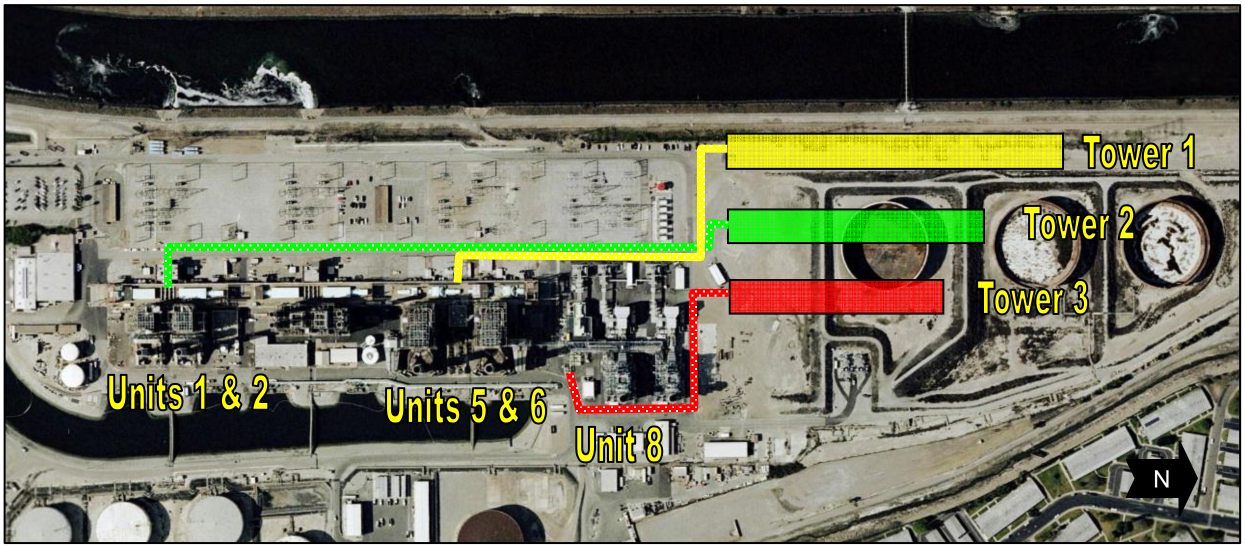

Figure F–5. Location of Cooling Towers and Underground Piping

3.3.3 PIPING

The main supply and return pipelines to and from all three towers will be located underground and made of prestressed concrete cylinder pipe (PCCP) suitable for saltwater applications. These pipes range in size from 84 to 120 inches in diameter. The distance between Units 1 and 2 and Tower 2 requires roughly 4,000 feet of PCCP for the supply and return lines, with less required to connect towers 1 and 3 to their respective units. Pipes connecting the condensers to the supply and return lines are made of FRP and placed above ground on pipe racks. Above-ground placement avoids the potential disruption that may be caused by excavation in and around the power block. The condensers at HnGS are all located at grade level, enabling a relatively straightforward connection.

Potential interference with underground obstacles and infrastructure is a concern, particularly at existing sites that are several decades old and have been substantially modified or rebuilt in the interim. Avoidance of these obstacles is considered to the degree practical in this study. Associated costs are included in the contingency estimate and are generally higher than similar estimates for new facilities (Section 4.3).

Appendix B details the total quantity of each pipe size and type for HnGS.

3.3.4 FANS AND PUMPS

Each tower cell utilizes an independent single-speed fan. Low-noise fan blades, gear box insulation, and fan deck barrier walls are included to reduce operating noise and allow compliance with local noise ordinances. The fan size and motor power are different in each tower.

This analysis includes new pumps to circulate water between the condensers and cooling towers. Pumps are sized according to the flow rate for each tower, the relative distance between the tower and condensers, and the total head required to deliver water to the top of the cooling tower riser. A separate, multilevel pump house is constructed for each cooling tower and is sized to accommodate the motor control centers (MCCs) and appropriate electrical switchgear. The electrical installation includes all necessary transformers, cabling, cable trays, lighting, and lightning protection. A 30-ton overhead crane is also included to allow for pump servicing.

Fan and pump characteristics associated with wet cooling towers at HnGS are summarized in Table F–8. The net electrical demand of the fans and new pumps are discussed further as part of the energy penalty analysis in Section 4.6.1.

Table F–8. Cooling Tower Fans and Pumps

		Tower 1 (Units 1 & 2)	Tower 2 (Units 5 & 6)	Tower 3 (Unit 8)
Fans	Number	13	18	10
	Type	Low noise Single speed	Low noise Single speed	Low noise Single speed
	Efficiency	0.95	0.95	0.95
	Motor power (hp)	219	263	198
Pumps	Number	3	3	2
	Type	50 % recirculating Mixed flow Suspended bowl Vertical	50 % recirculating Mixed flow Suspended bowl Vertical	50 % recirculating Mixed flow Suspended bowl Vertical
	Efficiency	0.88	0.88	0.88
	Motor power (hp)	2,174	3,326	1,785

3.4 ENVIRONMENTAL EFFECTS

Conversion of the existing once-through cooling system at HnGS to wet cooling towers will significantly reduce the intake of seawater from Alamitos Bay and will presumably reduce impingement and entrainment by a similar proportion. Because closed-cycle systems will almost always result in condenser cooling water temperatures higher than those found in a comparable once-through system, wet towers will increase the operating heat rates at all of HnGS's steam units, thereby decreasing the overall efficiency. Additional power will also be consumed by the operation of tower fans and circulating pumps. Depending on how HnGS chooses to address this change in efficiency, total stack emissions may increase for pollutants such as PM_{10}, SO_x, and NO_x and may require additional control measures or the purchase of emission credits to meet air quality regulations. No control measures are currently available for CO_2 emissions, which will increase, on a per-kWh basis, by the same proportion as any change in the heat rate. The towers themselves will constitute an additional source of PM_{10} emissions, the annual mass of which will largely depend on the utilization capacity for the generating units served by the tower.

If HnGS retains its National Pollutant Discharge Elimination System (NPDES) permit to discharge wastewater to the San Gabriel River with a wet cooling tower system, it may have to address revised effluent limitations resulting from the substantial change in the quantity and characteristics of the discharge. Thermal impacts from the current once-through system, if any, will be minimized through the use of a wet cooling system

3.4.1 AIR EMISSIONS

HnGS is located in the South Coast air basin (Los Angeles). Air emissions are permitted by the South Coast Air Quality Management District (SCAQMD) (Facility ID 800074).

Drift volumes are expected to be within the range of 0.5 gallons for every 100,000 gallons of circulating water in the towers. At HnGS, this corresponds to a rate of approximately 3 gpm, based on the maximum combined flow in the three towers. Areas potentially affected by drift deposition include residential neighborhoods located to the northeast and the Alamitos Generating Station (AGS) switchyard located to the northwest across the San Gabriel River. Optimal placement of the cooling towers considers the relative location of sensitive structures as well as the direction of prevailing winds in order to minimize any interference or impact from drift deposition. Deposition of high salinity drift in the vicinity could result in damage to the switchyard or other sensitive equipment. Any impact to residential and commercial areas from drift is likely to be considered more of a nuisance rather than a threat to public health or safety, and will manifest itself as a whitish coating on exposed surfaces. No agricultural areas are present in the vicinity of HnGS that could potentially be impacted by drift.

Total PM_{10} emissions from the HnGS cooling towers are a function of the number of hours in operation, overall water quality in the tower, and evaporation rate of drift droplets prior to deposition on the ground. Makeup water at HnGS will be obtained from the same source currently used for once-through cooling water (Long Beach Marina). This water is drawn through Alamitos Bay from the Pacific Ocean and is identical to marine water with respect to the total dissolved solids (TDS) concentration. At 1.5 cycles of concentration, and assuming an initial TDS value of 35 parts per thousand (ppt), the water within the cooling towers will reach a maximum TDS level of roughly 53 ppt. Any drift droplets exiting the tower will have the same TDS concentration.

The cumulative mass emission of PM_{10} from HnGS will increase as a result of the direct emissions from the cooling towers themselves. Stack emissions of PM_{10}, as well as SO_x, NO_x, and other pollutants, will increase due to the decrease in fuel efficiency, although the cumulative increase will depend on actual operations and emission control technologies currently in use. Maximum drift and PM_{10} emissions from the cooling towers are summarized in Table F–9.[7]

Data summarizing the total facility emissions for these pollutants in 2005 are presented in Table F–10 (CARB 2005). In 2005, HnGS operated at an annual capacity utilization of 15.7 percent.

[7] This is a conservative estimate that assumes all dissolved solids present in drift droplets will be converted to PM_{10}. Studies suggest this may overestimate actual emission profiles for saltwater cooling towers (Chapter 4).

Using this rate, PM_{10} emissions from the cooling towers alone would increase the facility total by approximately 32 tons/year, or 68 percent.[8]

Table F–9. Full Load Drift and Particulate Estimates

	PM_{10} (lbs/hr)	PM_{10} (tons/year)	Drift (gpm)	Drift (lbs/hr)
Tower 1	23	102	0.89	445
Tower 2	36	156	1.36	681
Tower 3	19	84	0.73	365
Total HnGS PM_{10} and drift emissions	**78**	**342**	**2.98**	**1,491**

Table F–10. 2005 Emissions of SO_x, NO_x, PM_{10}

Pollutant	Tons/year
NO_x	92.8
SO_x	6.1
PM_{10}	47.4

3.4.2 MAKEUP WATER

The makeup water flow requirements of the three cooling towers at HnGS is the sum of evaporative loss and the blowdown volume required to maintain the circulating water in the towers at the design TDS concentration. Drift expelled from the tower represents an insignificant volume by comparison. Makeup water requirements are based on design conditions, and may fluctuate seasonally based on climate and facility operations. Use of wet cooling towers will reduce once-through cooling water withdrawals from Alamitos Bay by approximately 96 percent over the current design intake capacity.

Table F–11. Makeup Water Demand

	Tower circulating flow (gpm)	Evaporation (gpm)	Blowdown (gpm)	Total makeup water (gpm)
Tower 1	177,800	2,800	5,600	8,400
Tower 2	272,000	3,800	7,600	11,400
Tower 3	146,000	1,800	3,500	5,300
Total HnGS makeup water demand	**595,800**	**8,400**	**16,700**	**25,100**

One circulating water pump, rated at 40,000 gpm, which is currently used to provide once-through cooling water to the facility, will be retained in a wet cooling system to provide makeup water to both cooling towers. The capacity of the retained pump exceeds the makeup demand capacity by approximately 15,000 gpm. Any excess capacity will be routed through a bypass conduit and returned to the intake canal at a point located behind the initial intake from Long Beach Marina. Recirculating the excess capacity in this manner reduces additional cost that would be incurred if new pumps were required, while maintaining the desired flow reduction. The

[8] 2006 emission data are not currently available from the Air Resources Board (ARB) Web site. For consistency, the comparative increase in PM_{10} emissions estimated here is based on the 2005 HnGS capacity utilization rate instead of the 2006 rate presented in Table F–4. All other calculations in this chapter use the 2006 value.

intake of new water, measured at the bulkhead wall in the marina, will be equal to the makeup water demand of the cooling towers. Figure F–6 presents a schematic of this configuration.

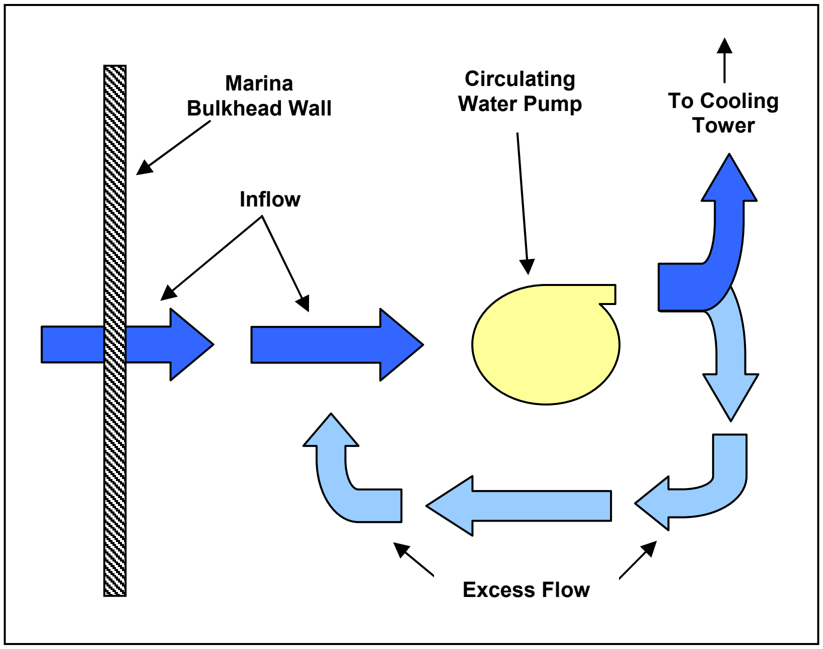

Figure F–6. Schematic of Intake Pump Configuration

The existing once-through cooling system at HnGS does not treat water withdrawn from Alamitos Bay with the exception of screening for debris and larger organisms and periodic chlorination to control biofouling in the condenser tubes. Heat treatments are also periodically used to control mussel growth on pipes and condenser tubes by raising the temperature of the circulating water to 115º F. Conversion to a wet cooling tower system will not interfere with chlorination or heat treatment operations.

Makeup water will continue to be withdrawn from the Alamitos Bay.

The wet cooling tower system proposed for HnGS includes water treatment for standard operational measures, i.e., fouling and corrosion control. Chemical treatment allowances are included in overall estimates and accounted for in annual O&M costs. It is assumed that the current once-through cooling water source quality is acceptable for use in a seawater cooling tower (with continued screening) and will not require any pretreatment to enable its use.

3.4.3 NPDES PERMIT COMPLIANCE

At maximum operation, wet cooling towers at HnGS will result in an effluent discharge of approximately 24 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, treated sanitary waste, and cleaning wastes. These low-volume wastes may add an additional 0.5 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, HnGS will be required to modify its existing individual wastewater discharge (NPDES) permit. Effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0000353, as implemented by

LARWQCB Order 00-081. All wastewaters are discharged to the San Gabriel River through one of six separate outfalls.

The existing order contains effluent limitations based on the 1997 Ocean Plan and 1972 Thermal Plan. By letter dated January 21, 2003, the LARWQCB notified HnGS that the facility's receiving water, the San Gabriel River, had been reclassified from a marine water body to an estuarine water body for the purposes of wastewater discharge permitting (LARWQCB 2003). Thus, in subsequent permit renewals, any water quality–based effluent limitations (WQBELs) will be based on the California Toxics Rule (CTR) and the State Implementation Policy for Inland Waters (SIP).

HnGS will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities (40 CFR 423.13(d)(1)). These ELGs set numeric limitations for chromium and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity). Because ELGs are technology-based limitations, mixing zones or dilution factors are not applicable when determining compliance; limits must be met at the point of discharge from the cooling tower prior to commingling with any other waste stream. ELGs for cooling tower blowdown target priority pollutants that are contributed by maintenance chemicals and do not apply when limits may be exceeded as a result of background concentrations or other sources. Further discussion can be found in Chapter 4, Section 3.6.

Conversion to wet cooling towers will alter the volume and composition of a facility's wastewater discharge because wet towers concentrate certain pollutants in the effluent waste stream. The cooling towers designed for HnGS operate at 1.5 cycles of concentration, i.e., the blowdown discharge will contain a dissolved solids concentration 50 percent higher than the makeup water.

Changes to discharge composition may affect compliance with water quality criteria included in the SIP. If compliance with these objectives becomes problematic, alternative treatment or discharge methods may be necessary. Data submitted by HnGS in support of its NPDES renewal application demonstrates a reasonable potential to exceed effluent limitations for copper, mercury, nickel, and zinc (LADWP 2004). These assessments reflect the existing once-through cooling system and are primarily driven by the elevated concentrations detected in the intake water at HnGS. Compliance may be achieved by altering the discharge configuration in such a way as to increase dilution (e.g., diffuser ports), or by seeking a mixing zone and dilution credits as permissible under the SIP and Basin Plan. Alternately, some low volume waste streams (e.g., boiler blowdown, laboratory drains) may be diverted, with necessary permits, for treatment at a POTW.

The SIP does make an allowance for intake credits under some circumstances but none would be applicable to HnGS due to the fact that a cooling tower effectively changes the intake water characteristics by concentrating pollutants (through evaporation) by as much as 50 percent above their initial levels. In addition, the current receiving water (San Gabriel River) may not meet the criteria establishing it as "hydrologically connected" to Alamitos Bay (SWRCB 2000).

If more pollutant-specific treatment methods, such as filtration or precipitation technologies, become necessary to meet WQBELs, the initial capital cost may range from $2 to $5.50 per 1,000 gallons of treatment capacity, with annual costs of approximately $0.5 per gallon of capacity, depending on the method of treatment (FRTR 2002). Hazardous material disposal fees and permits would further increase costs.

This evaluation did not include alternative discharge or effluent treatment measures in the conceptual design because the variables used to determine final WQBELs, which would be used to determine the type and scope of the desired compliance method, cannot be quantified here. Likewise, the final cost evaluation (Section 4.0) does not include any allowance for these possibilities.

Use of reclaimed water as the cooling tower makeup source has the potential to reduce or eliminate conflicts with effluent limitations (see Section 3.4.4).

Existing thermal discharges to an estuary are limited to a maximum discharge temperature of 20º F above the receiving water's natural temperature, may not exceed 86º F, and meet other criteria specified by the Thermal Plan (SWRCB 1972). It is unclear if HnGS will be able to meet this thermal limitation based on the current once-through configuration, with discharge temperatures reaching as high as 100º F and ambient water temperatures in the mid- to upper 60s. Compliance is also uncertain with wet cooling towers but is more likely given that blowdown discharge will be taken from the cold water side of the system, ensuring an effluent discharge temperature not in excess of 81º F for normal operations (not including heat treatments). This temperature is below the maximum permissible discharge temperature and within the required 20º F range of ambient temperatures in the San Gabriel River, although other criteria would also have to be met.

3.4.4 RECLAIMED WATER

The use of reclaimed or alternative water sources could potentially eliminate all surface water withdrawals at HnGS. Doing so would completely eliminate impingement and entrainment concerns, and might enable the facility to avoid possible effluent quality and permit compliance issues, depending on the quality of reclaimed water available for use. In addition, wet cooling towers using reclaimed water would be expected to have lower PM_{10} emissions due to the lower TDS levels. The SWRCB, in 1975, issued a policy statement requiring the consideration of alternative cooling methods in new power plants, including the use of reclaimed water, over the use of freshwater (SWRCB 1975). There is no similar policy regarding the use of marine waters, but the clear preference of state agencies is to encourage alternative cooling methods, including the use of reclaimed water, wherever possible.

The present volume of available reclaimed water within a 15-mile radius of HnGS (635 mgd) does not meet the current once-through cooling demand; thus, the use of reclaimed water is only applicable as a source of makeup water for a wet cooling tower system. This study did not pursue a detailed investigation of the use of reclaimed water because the conversion of the HnGS once-through cooling system to saltwater cooling towers enables the facility to meet the performance targets for impingement and entrainment impact reductions discussed in the 2006 OPC *Resolution on Once-Through Cooling Water* (See Chapter 1).

To be acceptable for use as makeup water in cooling towers, reclaimed water must meet tertiary treatment and disinfection standards under California Code of Regulations (CCR) Title 22. If the reclaimed water is not treated to the required levels, HnGS would be required to provide sufficient treatment onsite prior to use in the cooling towers. An additional consideration for the use of reclaimed water is the presence of any ammonia or ammonia-forming compounds in the reclaimed water. With the exception of the Unit 8 condenser, which has titanium tubes, all the condenser tubes at HnGS contain copper alloys (aluminum brass and copper-nickel) and can experience stress-corrosion cracking as a result of the interaction between copper and ammonia. Treatment for ammonia may include the addition of ferrous sulfate as a corrosion inhibitor or require ammonia-stripping towers to pretreat reclaimed water prior to use in the cooling towers (USEPA 2001).

Five publicly owned treatment works (POTWs) were identified within a 15-mile radius of HnGS, with a combined discharge capacity of 635 mgd (Figure F–7).

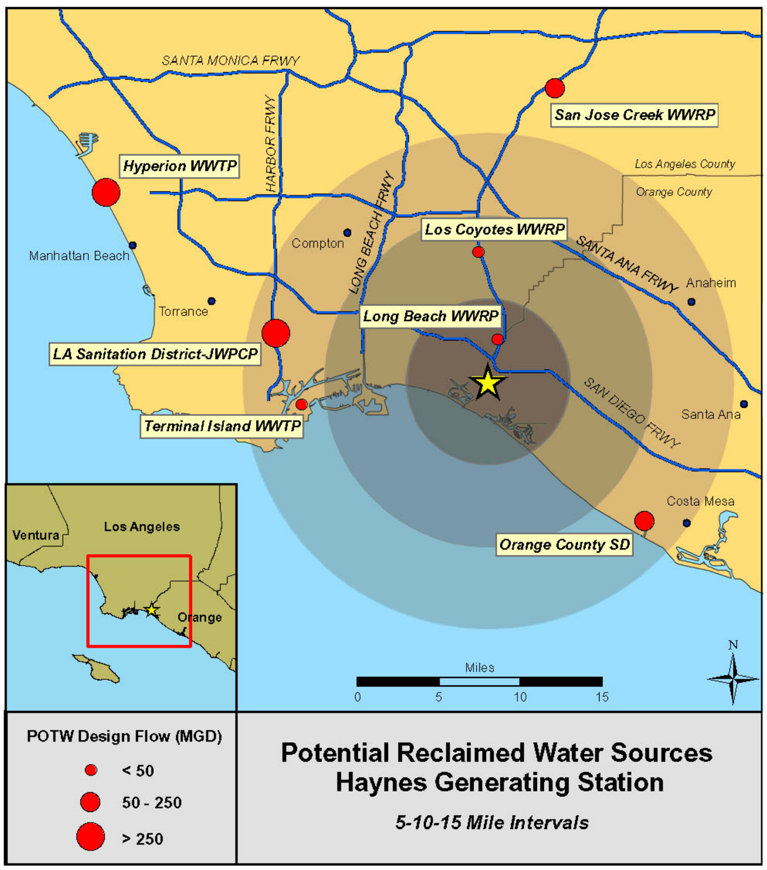

Figure F–7. Reclaimed Water Sources

- *Los Angeles Sanitation District, Joint Water Pollution Control Plant (JWPCP)—Carson*
  Discharge volume: 330 mgd
  Distance: 14 miles NW
  Treatment level: Secondary

  The facility representative at JWPCP indicated that the effluent is not currently considered a potential source of reclaimed water for irrigation due to high TDS concentrations (brine from the Hyperion WWTP is treated at Carson), but the suitability for use as a makeup water source is not currently known. TDS levels may be less than normally found in seawater and thus be at least comparable to the current makeup water source at HnGS. In the future, a portion of the effluent may be used for a new hydrogen plant under consideration by BP (formerly British Petroleum), but no formal agreement currently exists. Even with such an agreement, sufficient capacity would remain to satisfy the full makeup water demand for freshwater towers at HnGS (17 to 20 mgd).

- *Los Coyotes Wastewater Reclamation Plant—Cerritos*
  Discharge volume: 33 mgd
  Distance: 9 miles N
  Treatment level: 30% tertiary; 70% secondary

  Approximately 10 mgd are treated to tertiary standards and reused for irrigation at various locations in the area, leaving approximately 23 mgd available as a makeup water source. The remaining 23 mgd would require additional treatment prior to use at HnGS.

- *Terminal Island Wastewater Treatment* Plant *(WWTP)—San Pedro*
  Discharge volume: 20 mgd
  Distance: 10 miles W
  Treatment level: 10% tertiary; 90% secondary

  Tertiary treated water is used for local irrigation. A previous study to assess the feasibility of using Terminal Island's reclaimed water at Harbor Generating Station determined the water quality (pH) would have adverse effects on the condenser and cooling system, although treatment systems could be installed onsite to condition the water to an acceptable pH level.

- *Orange County Sanitation Dis*trict Wastewater Treatment Plant—Huntington Beach
  Discharge volume: 232 mgd
  Distance: 13 miles SE
  Treatment level: Secondary

  Sufficient capacity exists to supply the full makeup water demand for a freshwater tower at HnGS (17 to 20 mgd), although any use would require additional onsite treatment.

- *Long Beach Wastewater Treatment Plant—Long Beach*
  Discharge volume: 20 mgd
  Distance: 3 miles N
  Treatment level: Tertiary

  Approximately 50 percent is currently used for irrigation in the vicinity of the plant. The remaining capacity could supply 20–30 percent of the makeup water demand for an HnGS freshwater cooling tower.

The costs associated with the installation of transmission pipelines (excavation/drilling, material, labor), in addition to design and permitting costs, are difficult to quantify in the absence of a detailed analysis of various site-specific parameters that will influence the final configuration. The nearest facility with sufficient capacity to satisfy HnGS's makeup demand (17 to 20 mgd as a freshwater tower) is located approximately 10 miles from the site (JWPCP). Transmission pipelines would have to traverse a heavily urbanized area and navigate infrastructure obstacles such as freeways and flood control channels. Based on vendor-provided data compiled for this study, the estimated installed cost of a 36-inch prestressed concrete cylinder pipe, sufficient to provide 20 mgd to HnGS, is $514 per linear foot, or approximately $2.7 million per mile. Additional considerations, such as pump capacity and any required treatment, would increase the total cost.

Regulatory concerns beyond the scope of this investigation, however, may make the use of reclaimed water comparable or preferable to the use of saltwater from marine sources as makeup water. Reclaimed water may enable HnGS to reduce PM_{10} emissions from the cooling tower, which is a concern, given the current nonattainment status of the South Coast air basin, or eliminate potential conflicts with water discharge limitations. HnGS might realize other benefits by using reclaimed water in the form of reduced operations and maintenance (O&M) costs. At any facility where wet cooling towers are a feasible alternative, reclaimed water may be used as a makeup water source; the practicality of its use, however, is a question of the overall cost, availability, and additional environmental benefit that may be realized.

3.4.5 THERMAL EFFICIENCY

The use of wet cooling towers at HnGS will increase the temperature of the condenser inlet water by a range of 11 to 13° F above the surface water temperature, depending on the ambient wet bulb temperature at the time. The generating units at HnGS are designed to operate at the conditions described in Table F–12. The resulting monthly difference between once-through and wet cooling tower condenser inlet temperatures at HnGS is described in Figure F–8.

Table F–12. Design Thermal Conditions

	Units 1 & 2	Units 5 & 6	Unit 8
Design backpressure (in. HgA)	1.5	1.5	1.56
Design water temperature (°F)	62	62	63
Turbine inlet temperature (°F)	1,000	1,000	850 [1]
Turbine inlet pressure (psia)	2,400	3,500	900 [1]
Full load heat rate (BTU/kWh) [2],[3]	9,680	9,370	6,200

[1] Steam turbine inlet conditions.
[2] Operational heat rates (CEC 2002).
[3] Unit 8 heat rate estimated based on performance of other combined cycle units (Moss Landing).

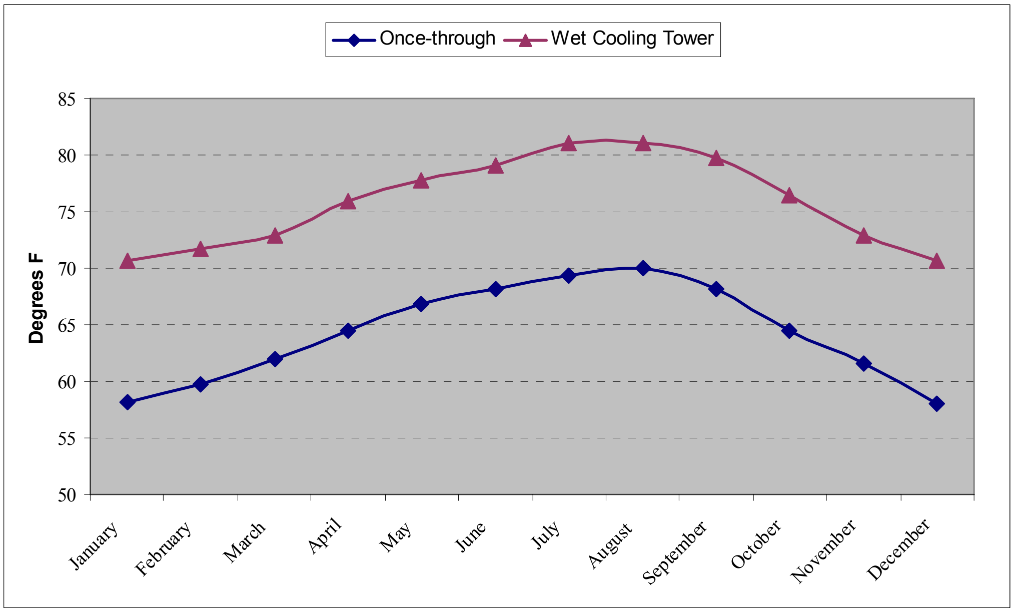

Figure F–8. Condenser Inlet Temperatures

Backpressures for the once-through and wet cooling tower configurations were calculated using the design criteria described in the sections above on a monthly basis using ambient climate data (Table F–6). In general, backpressures associated with the wet cooling tower were elevated by 0.5 to 0.75 inches HgA compared with the current once-through system (Figure F–9, Figure F–11, Figure F–13).

Heat rate adjustments were calculated by comparing the theoretical change in available energy that occurs at different turbine exhaust backpressure values, assuming the thermal load and turbine inlet pressure remain constant, i.e., at the maximum load rating. The relative change at different backpressures was compared to the value calculated for the design conditions (i.e., at design turbine inlet and exhaust backpressures) and plotted as a percentage of the maximum operating heat rate (Table F–12) to develop estimated correction curves (Figure F–10, Figure F–12, and Figure F–14). A comparison was then made between the relative heat rates of the once-through and wet cooling systems for a given month. The difference between these two values represents the net increase in heat rate that would be expected in a converted system.

Table F–13 summarizes the annual average heat rate increase for each unit pair as well as the increase associated with the peak demand period of July-August-September. Monthly values were used to develop an estimate of the monetized value of these heat rate changes (Section 4.6). Month-by-month calculations are presented in Appendix A.

Table F–13. Summary of Estimated Heat Rate Increases

	Units 1 & 2	Units 5 & 6	Unit 8 [1]
Peak (July-August-September)	1.24%	1.37%	0.56%
Annual average	1.04%	1.13%	0.45%

[1] Combined-cycle unit (gas and steam turbines).

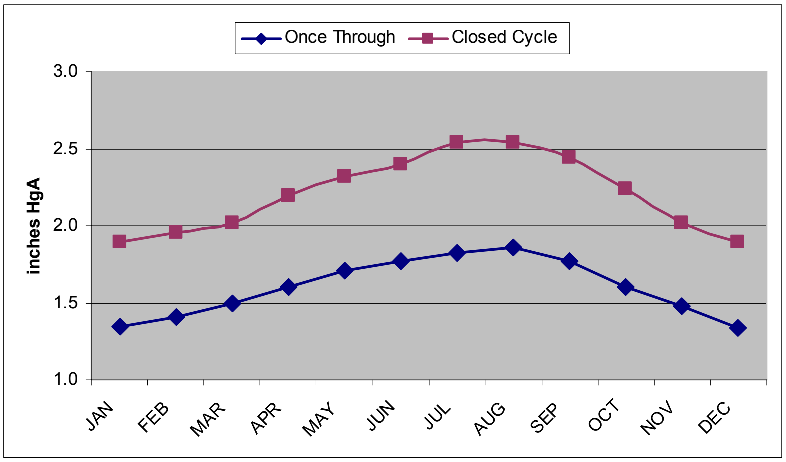

Figure F-9. Estimated Backpressures (Units 1 & 2)

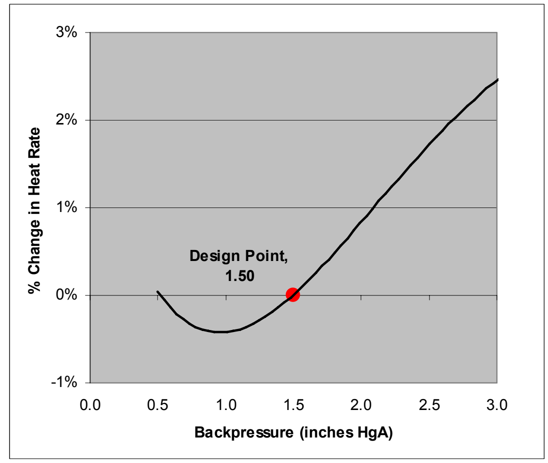

Figure F-10. Estimated Heat Rate Correction (Units 1 & 2)

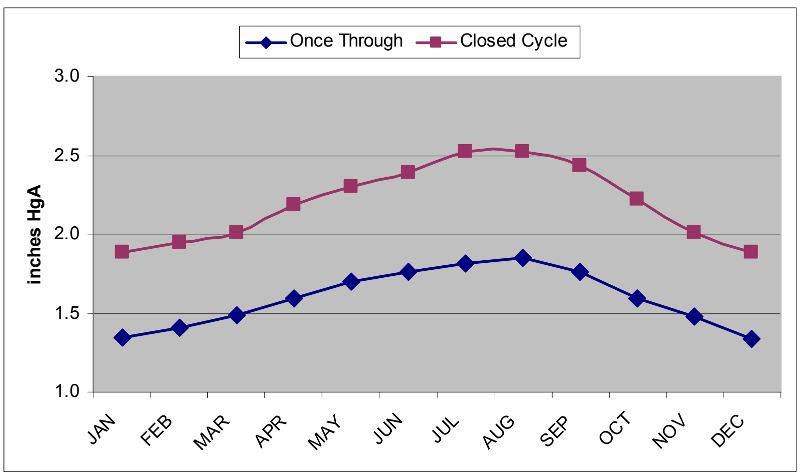

Figure F-11. Estimated Backpressure (Units 5 & 6)

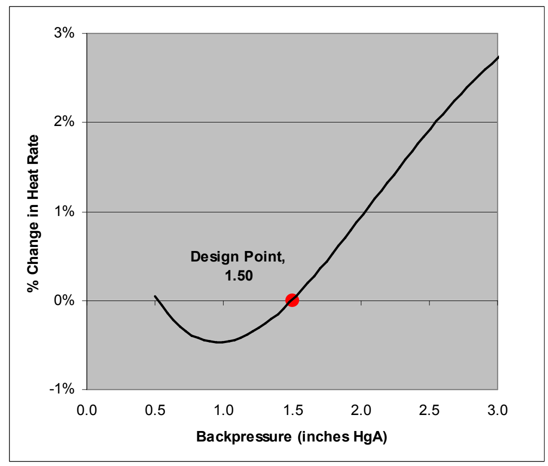

Figure F-12. Estimated Heat Rate Correction (Units 5 & 6)

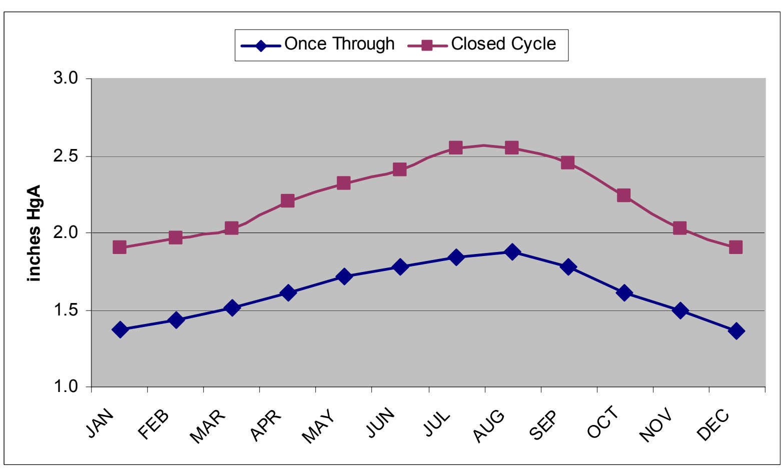

Figure F-13. Estimated Backpressures (Unit 8)

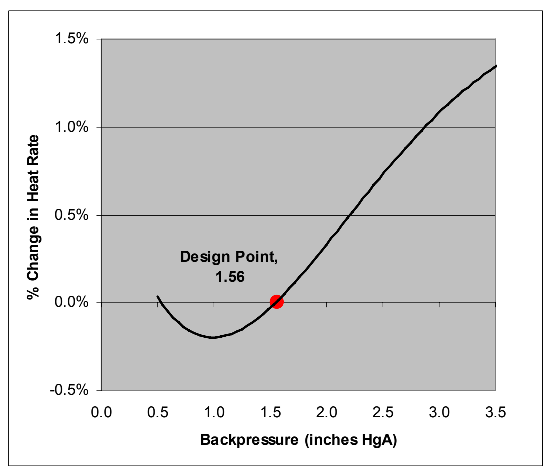

Figure F-14. Estimated Heat Rate Correction (Unit 8)

4.0 RETROFIT COST ANALYSIS

The wet cooling system retrofit estimate for HnGS is based on the incorporation of conventional wet cooling towers as a replacement for the existing once-through systems for each unit. Standard cost elements for this project include the following:

- Direct (cooling tower installation, civil/structural, mechanical, piping, electrical, and demolition)
- Indirect (smaller project costs not itemized)
- Contingency (allowance for unknown project variables)
- Operations and maintenance (non-energy-related cooling tower operations)
- Energy penalty (includes increased parasitic use from fans and pumps as well as decreased thermal efficiency)
- Revenue loss from shutdown (net loss in revenue during construction phase)

The cost analysis does not include allowances for elements that are not quantified in this study, such as land acquisition, effluent treatment, or air emission reduction credits. The methodology used to develop cost estimates is discussed in Chapter 5.

4.1 COOLING TOWER INSTALLATION

The wet cooling system retrofit estimate for HnGS is based on incorporating a conventional wet cooling tower as a replacement for the existing once-through system. Table B–14 summarizes the design-and-build cost estimate for each tower developed by vendors, inclusive of all labor and management required for their installation.

Table F–14. Wet Cooling Tower Design-and-Build Cost Estimate

	Units 1 & 2	Units 5 & 6	Unit 8	HnGS total
Number of cells	13	18	10	**41**
Cost/cell ($)	632,169	624,828	573,520	**614,641**
Total HnGS D&B cost ($)	**8,218,197**	**11,246,904**	**5,735,200**	**25,200,281**

4.2 OTHER DIRECT COSTS

A significant portion of the cost incurred for the wet cooling tower installation results from the various support structures and materials (pipes, pumps, etc.), as well the necessary equipment and labor required to prepare the cooling tower site and connect the towers to the cooling system. At HnGS, these costs comprise approximately 70 percent of the initial capital cost. Line item costs are detailed in Appendix B.

Deviations from or additions to the general cost elements discussed in Chapter 3 are discussed below. Other direct costs (non–cooling tower) for HnGS are summarized in Table F–15. Costs for Unit 8 only are summarized in Table F–16.

- *Civil, Structural, and Piping*
  The configuration of the HnGS site allows Tower 3 to be located relatively close to Unit 8. Tower 1 and Tower 2, however, must be placed at a substantial distance from their respective units. The distance required for Tower 2 notably increases material and labor costs—primarily as they relate to the installation of supply and return piping (approximately 4,000 feet total). Total costs are also affected by the necessity of constructing a 16-foot-high concrete barrier wall to meet Long Beach noise control ordinances.
- *Mechanical and Electrical*
  Initial capital costs in this category reflect the incorporation of new pumps (eight total) to circulate cooling water between the towers and condensers. Overall pump capacity is larger than a baseline arrangement due, in part, to the distance required to circulate water between Tower 1 and Tower 2 and their respective units. No new pumps are required to provide makeup water from Alamitos Bay. Electrical costs are based on the battery limit after the main feeder breakers.
- *Demolition*
  A cost allowance is included for the demolition of the remaining fuel tanks at the northern end of the property. It is assumed that the tanks have been decommissioned and will not require additional cleanup costs for hazardous material; no such allowance is included in the cost estimate.

Table F–15. Summary of Other Direct Costs (HnGS Total)

	Equipment ($)	Bulk material ($)	Labor ($)	HnGS total ($)
Civil/structural/piping	8,900,000	21,900,000	16,000,000	**46,800,000**
Mechanical	11,220,000	0	500,000	**11,720,000**
Electrical	2,000,000	3,600,000	2,500,000	**8,100,000**
Demolition	0	0	1,600,000	**1,600,000**
Total HnGS other direct costs	**22,120,000**	**25,500,000**	**20,600,000**	**68,220,000**

Table F–16. Summary of Other Direct Costs (Unit 8 Only)

	Equipment ($)	Bulk material ($)	Labor ($)	HnGS total ($)
Civil/structural/piping	3,100,000	5,800,000	5,300,000	**14,200,000**
Mechanical	2,140,000	0	100,000	**2,240,000**
Electrical	700,000	1,100,000	800,000	**2,600,000**
Demolition	0	0	1,200,000	**1,200,000**
Unit 8 only other direct costs	**5,940,000**	**6,900,000**	**7,400,000**	**20,240,000**

4.3 INDIRECT AND CONTINGENCY

Indirect costs are calculated as 25 percent of all direct costs (civil/structural, mechanical, electrical, demolition, and cooling towers). An additional allowance is included for reinforcement of the condenser to withstand the increased pressures resulting from incorporation of wet cooling towers. Each condenser may require reinforcement of the tube sheet bracing with 6-inch x 1-inch steel, and water box reinforcement/replacement with 5/8-inch carbon steel. Based on the data outlined in Chapter 3, a conservative estimate of 5 percent of all direct costs is included to account for possible condenser modifications.

The contingency cost is calculated as 25 percent of the sum of all direct and indirect costs, including condenser reinforcement. At HnGS, potential costs in this category include relocation or demolition of small buildings and structures and the potential interference with underground structures. Soils were not characterized for this analysis. HnGS lies within the coastal plain at approximately 10 feet above sea level and is bordered by water to the east and west. Groundwater intrusion or the instability of soils may require additional pilings to support any large structures built at the site. Initial capital costs are summarized in Table F–17.

Table F–17. Summary of Initial Capital Costs

	HnGS total ($)	Unit 8 only ($)
Cooling Towers	25,200,000	5,700,000
Civil/structural	46,800,000	14,200,000
Mechanical	11,700,000	2,200,000
Electrical	8,100,000	2,600,000
Demolition	1,600,000	1,200,000
Indirect cost	23,400,000	6,500,000
Condenser modification	4,700,000	1,300,000
Contingency	30,400,000	8,500,000
Total HnGS capital cost	**151,900,000**	**42,200,000**

4.4 SHUTDOWN

A portion of the work relating to the installation of wet cooling towers can be completed without significant disruption to the operations of HnGS. Units will be offline depending on the length of time it takes to integrate the new cooling system and conduct assurance testing. For HnGS, a conservative estimate of 6 weeks per unit was developed. Based on 2006 generating output, Unit 1, Unit 2, Unit 5, and Unit 6 would not experience any significant disruption to output. Among the four units, sufficient excess capacity appears to be available so that tie-ins could be staggered and thereby allow three of the four to be available at a given time.

Actual generating data for Unit 8 is not available; thus, any downtime estimate is somewhat speculative. Based on the fact that Unit 8 is a combined-cycle unit and, as such, typically operates at a higher capacity utilization rate, this study assumed some downtime loss during tie-in. If construction were scheduled to coincide with the lowest generating period of the year, Unit 8 might be offline for 6 weeks during April and May and incur an estimated revenue loss of $5.1 million. Table F–18 summarizes the estimated loss for Unit 8.

Table F–18. Estimated Revenue Loss from Construction Shutdown (Unit 8)

Estimated output (MWh)	Heat rate (BTU/kWh)	Wholesale fuel price ($/MMBTU)	Wholesale electricity price ($/MWh)	Fuel cost ($)	Gross revenue ($)	Difference ($)
175,000	6,500	5.00	60	5,425,000	**10,500,000**	**5,075,000**

This analysis did not consider shutdown with respect to the required availability of a particular generating unit, nor can it automatically be assumed that the generating profile for 2006 will be the same in each subsequent year. Net output data from 2006 may not reflect any contractual obligations that mandate a particular unit's availability during a given time period.

4.5 OPERATIONS AND MAINTENANCE

O&M costs for a wet cooling tower system at HnGS include routine maintenance activities; chemicals and treatment systems to control fouling and corrosion in the towers; management and labor; and an allowance for spare parts and replacement. Annual costs are calculated based on the circulating water flow capacity of the towers using a base cost of $4.00/gpm in Year 1 and $5.80/gpm in Year 12, with an annual escalator of 2 percent (USEPA 2001). Year 12 costs increase based on the assumption that maintenance needs, particularly for spare parts and replacements, will be greater for years 12–20. Annual O&M costs, based on the design circulating water flow for the three cooling towers at HnGS (595,800 gpm), as well as an annual cost for Unit 8 alone (based on a flow of 146,000 gpm), are presented in Table F–19. These costs reflect maximum operation.

Table F–19. Annual O&M Costs (Full Load)

	HnGS total	
	Year 1 ($)	Year 12 ($)
Management/labor	595,800	863,910
Service/parts	953,280	1,382,256
Fouling	834,120	1,209,474
Total HnGS O&M cost	**2,383,200**	**3,455,640**

	Unit 8 only	
	Year 1 ($)	Year 12 ($)
Management/labor	146,000	211,700
Service/parts	233,600	338,720
Fouling	204,400	296,380
Unit 8 O&M cost	**584,000**	**846,800**

4.6 ENERGY PENALTY

The energy penalty is divided into two components: increased parasitic use resulting from the additional electrical demand of cooling tower fans and pumps; and the decrease in thermal efficiency resulting from elevated turbine backpressure values. Monetizing the energy penalty at HnGS requires some assumption as to how the facility will choose to alter its operations to compensate for these changes, if at all. One option would be to accept the reduced amount of revenue-generating electricity available and absorb the economic loss ("production loss option"). A second option would be to increase the firing rate to the turbine (i.e., consume more fuel) and produce the same amount of revenue-generating electricity as had been obtained with the once-through cooling system ("increased fuel option"). A more likely option, however, is some combination of the two.

Ultimately, the manner in which HnGS would alter operations to address efficiency changes is driven by considerations unknown to this study (e.g., corporate strategy, contractual obligations, operating protocols and turbine pressure tolerances). In all summary cost estimates, this study calculates the energy penalty's monetized value by assuming the facility will use the increased fuel option to compensate for reduced efficiency and generate the amount of electricity equivalent to the estimated shortfall. With this option, the energy penalty is equivalent to the financial cost of additional fuel and is nominally less costly than the production loss option. This option, however, may not reflect long-term costs such as increased maintenance or system degradation that may result from continued operation at a higher-than-designed turbine firing rate.

The energy penalty for HnGS is calculated by first estimating the increased parasitic demand from the cooling tower pumps and fans, expressed as a percentage of the rated capacity of the particular unit(s). Likewise, the change in the unit's heat rate (Section 3.4.5) is also expressed as a capacity percentage.

4.6.1 INCREASED PARASITIC USE (FANS AND PUMPS)

Depending on ambient conditions or the operating load at a given time, HnGS may be able to take one or more cooling tower cells offline and still obtain the required level of cooling. This would also reduce the cumulative electrical demand from the fans. For the purposes of this study, however, operations are evaluated at the design conditions, i.e., maximum load; no allowance is made for seasonal changes. The increased electrical demand associated with operation of the cooling tower fans is summarized in Table F–20.

Table F–20. Cooling Tower Fan Parasitic Use

	Tower 1	Tower 2	Tower 3	HnGS total
Units served	Units 1 & 2	Units 5 & 6	Unit 8	--
Generating capacity (MW)	444	600	575	**1,619**
Number of fans (one per cell)	13	18	10	**41**
Motor power per fan (hp)	219	263	198	**--**
Total motor power (hp)	2,846	4,737	1,979	**9,562**
MW total	2.12	3.53	1.48	**7.13**
Fan parasitic use (% of capacity)	**0.48**	**0.59**	**0.26**	**0.44**

The addition of new circulating water pump capacity for the wet cooling towers will also increase the parasitic use of electricity at HnGS. Makeup water will continue to be withdrawn from the Long Beach Marina through the use of one of the existing circulating water pumps currently serving Unit 8; the remaining pumps will be retired. The net increase in pump-related parasitic usage is the difference between the new wet cooling tower configuration (new plus retained pumps) and the existing once-through configuration. Because one of the main design assumptions maintains the existing flow rate through each condenser, the new circulating pumps are single speed and are assumed to operate at their full rated capacity when in use. The increased electrical demand associated with operation of the cooling tower pumps is summarized in Table F–21.

Table F–21. Cooling Tower Pump Parasitic Use

	Tower 1	Tower 2	Tower 3	HnGS total
Units served	Units 1 & 2	Units 5 & 6	Unit 8	--
Generating capacity (MW)	444	600	575	**1,619**
Existing pump configuration (hp)	4,174	6,957	3,478	**14,609**
New pump configuration (hp)	7,022	10,478	3,570	**21,070**
Difference (hp)	2,848	3,521	92	**6,461**
Difference (MW)	2.1	2.6	0.1	**4.8**
Net pump parasitic use (% of capacity)	**0.48%**	**0.44%**	**0.01%**	**0.30%**

4.6.2 HEAT RATE CHANGE

Adjustments to the heat rate were calculated based on the ambient conditions for each month and reflect the estimated difference between operations with once-through and wet cooling tower systems. As noted above, the energy penalty analysis assumes HnGS will increase its fuel consumption to compensate for lost efficiency as well as the increased parasitic load from fans and pumps. The overfiring of the turbine will increase the thermal load rejected to the condenser, which, in turn, results in a higher backpressure value and corresponding increase in the heat rate. No data are available describing the changes in turbine backpressures at higher thermal loads. For the purposes of monetizing the energy penalty only, this study conservatively assumed an additional increase in the heat rate of 0.5 percent for overfiring. Changes in the heat rate for each unit pair at HnGS are presented in Figure F–11 through Figure F–13.

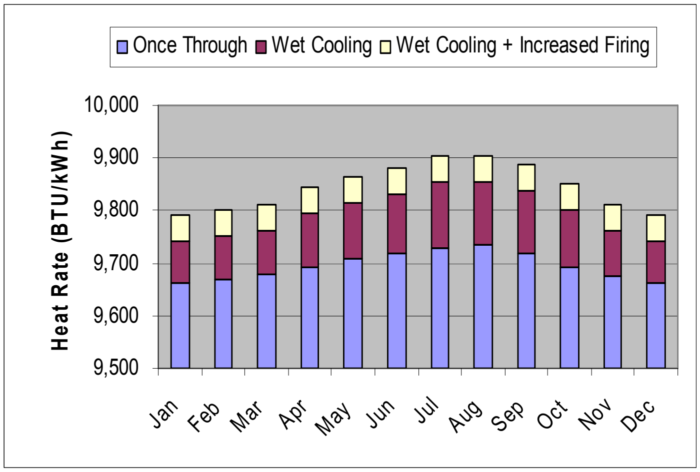

Figure F-11. Estimated Heat Rate Change (Units 1 & 2)

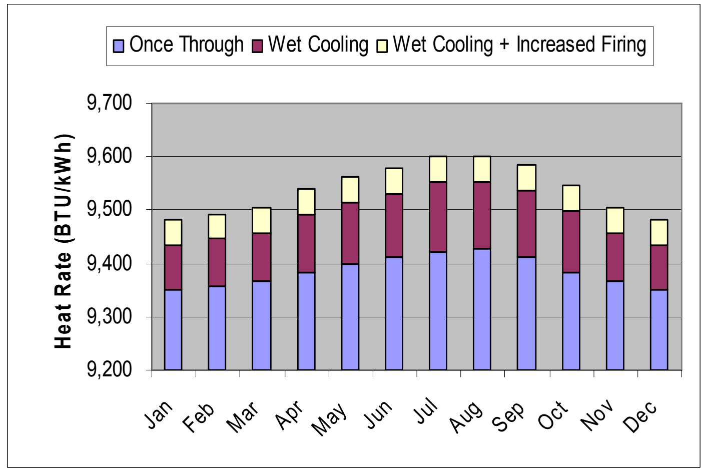

Figure F-12. Estimated Heat Rate Change (Units 3 & 4)

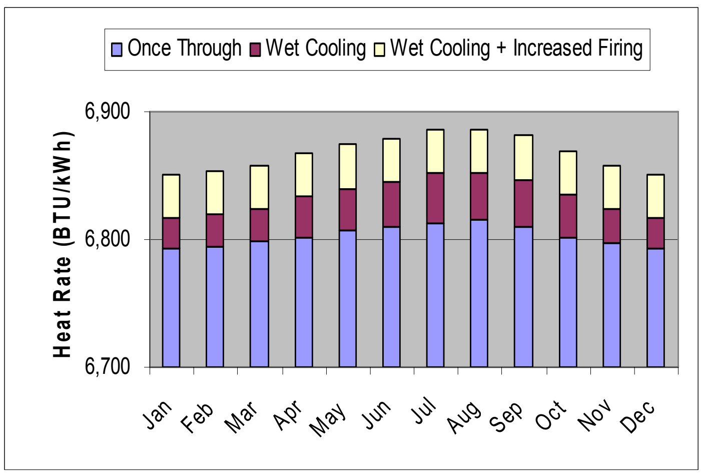

Figure F-13. Estimated Heat Rate Change (Unit 8)

4.6.3 CUMULATIVE ESTIMATE

Using the increased fuel option, the cumulative value of the energy penalty is obtained by first calculating the relative costs of generation ($/MWh) for the once-through and overfired wet cooling systems. The cost of generation for HnGS is based on the relative heat rates developed in Section 4.6.2 and the average monthly wholesale natural gas cost ($/MMBTU) (ICE 2006). The difference between these two values represents the increased cost, per MWh, that results from the incorporation of wet cooling towers. The net difference in cost, per month, is applied to the net MWh generated for the particular month, and summed to determine an annual estimate.

Based on 2005 output data, the Year 1 energy penalty for HnGS will be approximately $2 million. In contrast, the energy penalty's value calculated using the production loss option would be approximately $4.3 million. Together, these values represent the range of potential energy penalty costs for HnGS. Table F-22, Table F-23, and Table F-24 summarize the energy penalty estimates for each unit using the increased fuel option.

Table F-22. Units 1 & 2 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	9,662	57.97	9,790	58.74	0.77	64,880	**49,897**
February	5.50	9,668	53.18	9,801	53.90	0.73	50,685	**36,888**
March	4.75	9,678	45.97	9,812	46.61	0.63	55,294	**35,053**
April	4.75	9,693	46.04	9,844	46.76	0.72	51,758	**37,041**
May	4.75	9,709	46.12	9,865	46.86	0.74	65,109	**48,147**
June	5.00	9,720	48.60	9,880	49.40	0.80	57,965	**46,278**
July	6.50	9,729	63.24	9,903	64.37	1.13	144,893	**163,503**
August	6.50	9,735	63.28	9,903	64.37	1.09	81,647	**88,985**
September	4.75	9,720	46.17	9,887	46.96	0.80	42,615	**33,891**
October	5.00	9,693	48.46	9,851	49.25	0.79	79,397	**62,593**
November	6.00	9,677	58.06	9,812	58.87	0.81	75,517	**61,365**
December	6.50	9,661	62.80	9,790	63.64	0.84	52,312	**43,869**
							Units 1 & 2 total	**707,510**

Table F-23. Units 5 & 6 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	9,350	56.10	9,481	56.89	0.79	71,801	**56,414**
February	5.50	9,357	51.46	9,493	52.21	0.74	112,213	**83,568**
March	4.75	9,368	44.50	9,505	45.15	0.65	114,100	**74,120**
April	4.75	9,383	44.57	9,538	45.31	0.74	27,293	**20,125**
May	4.75	9,400	44.65	9,561	45.41	0.76	0	**0**
June	5.00	9,412	47.06	9,577	47.88	0.83	15,371	**12,693**
July	6.50	9,422	61.24	9,602	62.41	1.17	70,737	**82,838**
August	6.50	9,428	61.28	9,602	62.41	1.13	132,257	**149,509**
September	4.75	9,412	44.70	9,585	45.53	0.82	58,133	**47,896**
October	5.00	9,383	46.91	9,546	47.73	0.81	0	**0**
November	6.00	9,366	56.19	9,505	57.03	0.83	2,307	**1,922**
December	6.50	9,350	60.77	9,481	61.63	0.86	0	**0**
							Units 5 & 6 total	**529,085**

Table F–24. Unit 8 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	6,793	40.76	6,851	41.10	0.35	225,000	77,639
February	5.50	6,795	37.37	6,854	37.70	0.32	170,000	55,137
March	4.75	6,798	32.29	6,858	32.57	0.28	120,000	33,974
April	4.75	6,802	32.31	6,867	32.62	0.31	110,000	34,127
May	4.75	6,807	32.33	6,874	32.65	0.32	120,000	38,317
June	5.00	6,810	34.05	6,879	34.39	0.34	180,000	61,841
July	6.50	6,813	44.28	6,886	44.76	0.48	240,000	114,482
August	6.50	6,815	44.30	6,886	44.76	0.47	260,000	121,003
September	4.75	6,810	32.35	6,881	32.69	0.34	180,000	60,886
October	5.00	6,802	34.01	6,870	34.35	0.34	140,000	47,275
November	6.00	6,797	40.78	6,858	41.15	0.36	120,000	43,316
December	6.50	6,793	44.15	6,851	44.53	0.38	200,000	75,077
							Unit 8 total	**763,074**

4.7 NET PRESENT COST

The Net Present Cost (NPC) of a wet cooling system retrofit at HnGS is the sum of all annual expenditures over the 20-year life span of the project and discounted according to the year in which the expense is incurred and the selected discount rate. The NPC represents the total change in revenue streams, in 2007 dollars, that HnGS can expect over 20 years as a direct result of converting to wet cooling towers. The following values were used to calculate the NPC at a 7 percent discount rate:

- *Capital and Start-up.* Includes all capital, indirect, contingency, and shutdown costs. All costs in this category are incurred in Year 0. (See Table F–17.)
- *Annual O&M.* Base cost values for Year 1 and Year 12 are adjusted for subsequent years using a 2 percent year-over-year escalator. Because HnGS has a relatively low capacity utilization factor, O&M costs for the NPC calculation were estimated at 60 percent of their maximum value. (See Table F–19.)
- *Annual Energy Penalty.* Sufficient information is not available to this study to forecast future generating capacity at HnGS. In lieu of annual estimates, this study uses the net MWh output from 2006 for Year 1 through Year 20, including a year-over-year escalation of 5.8 percent (based on the Producer Price Index) to wholesale cost. (See Table F–22 through Table F–24.)

Using these values, the NPC_{20} for HnGS is $200 million. For Unit 8 alone, the NPC_{20} is $65 million. Detailed annual calculations used to develop this cost for HnGS are presented in Appendix C. Appendix D presents calculations for Unit 8 only.

4.8 ANNUAL COST

The annual cost incurred by HnGS for the retrofit of the once-through cooling system is the sum of the annual amortized capital cost plus the annual average of O&M and energy penalty expenditures. Capital costs are amortized at a 7 percent discount rate over 20 years. O&M and energy penalty costs are calculated in the same manner as for the NPC_{20} (Section 4.7).

Table F–25. Annual Cost

	Discount rate (%)	Capital ($)	Annual O&M ($)	Annual energy penalty ($)	Annual cost ($)
HnGS total	7.00	14,300,000	1,900,000	3,600,000	**19,800,000**
Unit 8 Only	7.00	4,000,000	600,000	1,400,000	**6,000,000**

4.9 COST-TO-GROSS REVENUE COMPARISON

Financial data available to conduct a detailed analysis of the economic impact that a wet cooling system retrofit will have on annual revenues for HnGS are limited. As a publicly-owned utility, LADWP's gross revenues will include costs for transmission and distribution. An approximation of gross annual revenues was calculated using public data sources (US EIA 2005) that showed LADWP's average annual retail rate was $96/MWh. This rate was applied to the monthly net generating outputs for each unit in 2006 (CEC 2006) to arrive at a facility-wide revenue estimate. This estimate does not reflect seasonal adjustments that may translate to higher or lower per-MWh retail rates through the year, nor does it include other liabilities such as taxes or other operational costs.

The estimated gross revenue for HnGS is summarized in Table F–26. A comparison of annual costs to annual gross revenue is summarized in Table F–27.

Table F-26. Estimated Gross Revenue

	Retail rate ($/MWh)	Net generation (MWh)			Estimated gross revenue ($2007)			
		Units 1 & 2	Units 5 & 6	Unit 8	Units 1 & 2	Units 5 & 6	Unit 8	HnGS total
January	96	64,880	71,801	225,000	6,228,456	6,892,896	21,600,000	**34,721,352**
February	96	50,685	112,213	170,000	4,865,736	10,772,424	16,320,000	**31,958,160**
March	96	55,294	114,100	120,000	5,308,224	10,953,624	11,520,000	**27,781,848**
April	96	51,758	27,293	110,000	4,968,768	2,620,128	10,560,000	**18,148,896**
May	96	65,109	0	120,000	6,250,464	0	11,520,000	**17,770,464**
June	96	57,965	15,371	180,000	5,564,640	1,475,616	17,280,000	**24,320,256**
July	96	144,893	70,737	240,000	13,909,728	6,790,752	23,040,000	**43,740,480**
August	96	81,647	132,257	260,000	7,838,112	12,696,624	24,960,000	**45,494,736**
September	96	42,615	58,133	180,000	4,091,016	5,580,744	17,280,000	**26,951,760**
October	96	79,397	0	140,000	7,622,088	0	13,440,000	**21,062,088**
November	96	75,517	2,307	120,000	7,249,632	221,496	11,520,000	**18,991,128**
December	96	52,312	0	200,000	5,021,928	0	19,200,000	**24,221,928**
HnGS total		**822,072**	**604,212**	**2,065,000**	**78,918,792**	**58,004,304**	**198,240,000**	**335,163,096**

Table F-27. Cost-Revenue Comparison

	Estimated gross annual revenue ($)	Initial capital		O&M		Energy penalty		Total annual cost	
		Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross
HnGS total	335,200,000	14,300,000	4.3	1,900,000	0.6	3,600,000	1.1	**19,800,000**	**5.9**
Unit 8 only	225,400,000	4,000,000	1.8	600,000	0.3	1,400,000	0.6	**6,000,000**	**2.7**

5.0 OTHER TECHNOLOGIES

Within the scope of this study, and using the OPC resolution's stated goal of reducing impingement and entrainment by 90–95 percent as a benchmark, the effectiveness of other technologies commonly used to address such impacts could not be conclusively determined for use at HnGS. As with many existing facilities, the location and configuration of the site complicates the use of some technologies that might be used successfully elsewhere. A more detailed analysis that also comprises a biological evaluation may determine the applicability of one or more of these technologies to HnGS. A brief summary of the applicability of these technologies follows.

5.1 MODIFIED RISTROPH SCREENS—FINE MESH

The principal concern with this technology is the successful return of viable organisms captured on the screens to the source water body. HnGS currently withdraws its cooling water from Alamitos Bay. Water within the HnGS intake canal generally flows towards the facility due to the action of the circulating water pumps. Returning any collected organisms to the intake canal would likely result in reimpingement. Use of Alamitos Bay as the return location may address this concern, but potential concerns remain over the long-term viability of fragile organisms (eggs and larvae) transported over the long distance from the facility to the bay. Discharging organisms to the San Gabriel River may also be problematic because of the elevated temperatures (90º F and higher) that can dominate the near-discharge area (AGS and HnGS have the capacity to introduce more than 2,000 mgd of elevated-temperature water into this section of the San Gabriel River). Successful deployment of this technology might be feasible with a better understanding of the biological conditions in Alamitos Bay.

5.2 BARRIER NETS

The beginning of the CWIS at HnGS is the bulkhead wall located in the northeastern portion of the Long Beach Marina, and the likely location for deployment of a barrier net. Heavy recreational boating traffic and the narrow pathways within the marina limits are significant constraints on the use of a barrier net. For this reason, plus their ineffectiveness in reducing entrainment, barrier nets were not considered further in this study.

5.3 AQUATIC FILTRATION BARRIERS

Aquatic filtration barriers (AFBs), which are larger than barrier nets, are more limited than barrier nets for deployment at HnGS. Placement within the Long Beach Marina is infeasible.

5.4 VARIABLE SPEED DRIVES

Variable speed drives (VSDs) were not considered for analysis at HnGS because the technology alone cannot be expected to achieve the desired level of reductions in impingement and entrainment, nor could it be combined with another technology to yield the desired reductions. Pumps that have been retrofitted with VSDs can reduce overall flow intake volumes by 10–35 percent over the current once-through configuration (USEPA 2001). The actual reduction, however, will vary based on the cooling water demand at different times of the year. At peak demand, the pumps will essentially function as standard circulating water pumps and withdraw water at the maximum rated capacity, thus negating any potential benefit. Use of VSDs may be an economically desirable option when pumps are retrofitted or replaced for other reasons, but were not considered further for this study.

5.5 CYLINDRICAL FINE-MESH WEDGEWIRE

Fine-mesh cylindrical wedgewire screens have not been deployed or evaluated at coastal facilities for applications as large as would be required at HnGS (approximately 900 mgd). In order to function as intended, cylindrical wedgewire screens must be submerged in a water body with a consistent ambient current of 0.5 fps. Ideally, this current would be unidirectional so that screens may be oriented properly and any debris impinged on the screens will be carried downstream when the airburst cleaning system is activated.

HnGS currently withdraws cooling water from Alamitos Bay. Space constraints and navigation concerns prohibit the placement of any large cylindrical screens in the channel or bay, let alone the 10 to 12 84-inch-diameter screens that would be required to supply the facility with adequate volumes of water. The only theoretical location available for HnGS would be offshore in the Pacific Ocean, southwest of the entrance to Alamitos Bay. Information regarding the subsurface currents in the near-shore environment near Alamitos Bay is limited, but data suggest that currents are multidirectional depending on the tide and season, and fluctuate in terms of velocity, with prolonged periods below 0.5 fps (SCCOOS 2006). To attain sufficient depth (approximately 20 feet) and an ambient current that might allow deployment, screens would need to be located 2,000 feet or more offshore. Discussions with vendors who design these systems indicated that distances more than 1,000 to 1,500 feet become problematic due to the inability of the airburst system to maintain adequate pressure for sufficient cleaning (Someah 2007). Together, these considerations preclude further evaluation of fine-mesh cylindrical wedgewire screens at HnGS.

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Appendix A. Once-Through and Closed-Cycle Thermal Performance

		Units 1 & 2			Units 5 & 6			Unit 8		
		Once through	Closed cycle	Net increase	Once through	Closed cycle	Net increase	Once through	Closed cycle	Net increase
JAN	Backpressure (in. HgA)	1.35	1.90	**0.55**	1.35	1.89	**0.54**	1.37	1.91	**0.53**
	Heat rate Δ (%)	*-0.19*	*0.63*	***0.82***	*-0.21*	*0.69*	***0.89***	*-0.10*	*0.25*	***0.34***
FEB	Backpressure (in. HgA)	1.41	1.96	**0.55**	1.41	1.95	**0.54**	1.43	1.97	**0.54**
	Heat rate Δ (%)	*-0.12*	*0.74*	***0.86***	*-0.14*	*0.80*	***0.94***	*-0.07*	*0.29*	***0.37***
MAR	Backpressure (in. HgA)	1.49	2.02	**0.53**	1.49	2.01	**0.52**	1.51	2.03	**0.52**
	Heat rate Δ (%)	*-0.02*	*0.86*	***0.87***	*-0.02*	*0.93*	***0.95***	*-0.03*	*0.34*	***0.37***
APR	Backpressure (in. HgA)	1.60	2.20	**0.60**	1.59	2.18	**0.59**	1.61	2.20	**0.59**
	Heat rate Δ (%)	*0.13*	*1.18*	***1.05***	*0.14*	*1.29*	***1.15***	*0.03*	*0.49*	***0.46***
MAY	Backpressure (in. HgA)	1.70	2.32	**0.61**	1.70	2.30	**0.60**	1.72	2.32	**0.60**
	Heat rate Δ (%)	*0.30*	*1.40*	***1.10***	*0.32*	*1.53*	***1.21***	*0.10*	*0.59*	***0.49***
JUN	Backpressure (in. HgA)	1.77	2.40	**0.63**	1.76	2.39	**0.62**	1.78	2.41	**0.62**
	Heat rate Δ (%)	*0.41*	*1.55*	***1.14***	*0.44*	*1.70*	***1.25***	*0.15*	*0.66*	***0.51***
JUL	Backpressure (in. HgA)	1.83	2.54	**0.71**	1.82	2.52	**0.71**	1.84	2.54	**0.71**
	Heat rate Δ (%)	*0.51*	*1.79*	***1.28***	*0.55*	*1.96*	***1.41***	*0.19*	*0.77*	***0.58***
AUG	Backpressure (in. HgA)	1.86	2.54	**0.68**	1.85	2.52	**0.67**	1.87	2.54	**0.67**
	Heat rate Δ (%)	*0.57*	*1.79*	***1.22***	*0.62*	*1.96*	***1.35***	*0.22*	*0.77*	***0.55***
SEP	Backpressure (in. HgA)	1.77	2.45	**0.68**	1.76	2.43	**0.67**	1.78	2.45	**0.67**
	Heat rate Δ (%)	*0.41*	*1.63*	***1.22***	*0.44*	*1.79*	***1.34***	*0.15*	*0.69*	***0.54***
OCT	Backpressure (in. HgA)	1.60	2.23	**0.64**	1.59	2.22	**0.63**	1.61	2.24	**0.63**
	Heat rate Δ (%)	*0.13*	*1.26*	***1.12***	*0.14*	*1.37*	***1.23***	*0.03*	*0.52*	***0.49***
NOV	Backpressure (in. HgA)	1.48	2.02	**0.54**	1.47	2.01	**0.53**	1.50	2.03	**0.53**
	Heat rate Δ (%)	*-0.04*	*0.86*	***0.89***	*-0.04*	*0.93*	***0.98***	*-0.04*	*0.34*	***0.38***
DEC	Backpressure (in. HgA)	1.34	1.90	**0.56**	1.34	1.89	**0.55**	1.36	1.91	**0.54**
	Heat rate Δ (%)	*-0.20*	*0.63*	***0.83***	*-0.22*	*0.69*	***0.90***	*-0.10*	*0.25*	***0.35***

Note: Heat rate delta represents change from design value calculated according to estimated ambient conditions for each month.

Appendix B. Itemized Capital Costs

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
CIVIL / STRUCTURAL / PIPING	--	--	--	--	--	--	--	--	--	--
Allocation for other accessories (bends, water hammers…)	lot	1	--	--	500,000	500,000	4,000.00	85	340,000	**840,000**
Allocation for pipe racks (approx 1900 ft) and cable racks	t	190	--	--	2,500	475,000	17.00	105	339,150	**814,150**
Allocation for sheet piling and dewatering	lot	1	--	--	500,000	500,000	5,000.00	100	500,000	**1,000,000**
Allocation for testing pipes	lot	1	--	--	--	--	2,000.00	95	190,000	**190,000**
Allocation for Tie-Ins to existing condenser's piping	lot	1			250,000	250,000	2,000.00	85	170,000	**420,000**
Allocation for trust blocks	lot	1			25,000	25,000	250.00	95	23,750	**48,750**
Backfill for PCCP pipe (reusing excavated material)	m3	27,322					0.04	200	218,576	**218,576**
Bedding for PCCP pipe	m3	4,067			25	101,675	0.04	200	32,536	**134,211**
Bend for PCCP pipe 120" diam (allocation)	ea	6			35,000	210,000	100.00	95	57,000	**267,000**
Bend for PCCP pipe 36" & 48" diam (allocation)	ea	10			5,000	50,000	25.00	95	23,750	**73,750**
Bend for PCCP pipe 84" diam (allocation)	ea	2			20,000	40,000	50.00	95	9,500	**49,500**
Bend for PCCP pipe 96" diam (allocation)	ea	6			30,000	180,000	75.00	95	42,750	**222,750**
Building architectural (siding, roofing, doors, painting…etc)	ea	3			57,500	172,500	690.00	75	155,250	**327,750**
Butterfly valves 120" c/w allocation for actuator & air lines	ea	4	252,000	1,008,000			80.00	85	27,200	**1,035,200**
Butterfly valves 30" c/w allocation for actuator & air lines	ea	41	30,800	1,262,800			50.00	85	174,250	**1,437,050**
Butterfly valves 36" c/w allocation for actuator & air lines	ea	4	33,600	134,400			50.00	85	17,000	**151,400**
Butterfly valves 48" c/w allocation for actuator & air lines	ea	10	46,200	462,000			50.00	85	42,500	**504,500**
Butterfly valves 60" c/w allocation for actuator & air lines	ea	26	75,600	1,965,600			60.00	85	132,600	**2,098,200**
Butterfly valves 72" c/w allocation for actuator & air lines	ea	4	96,600	386,400			75.00	85	25,500	**411,900**
Butterfly valves 84" c/w allocation for actuator & air lines	ea	16	124,600	1,993,600			75.00	85	102,000	**2,095,600**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Butterfly valves 96" c/w allocation for actuator & air lines	ea	4	151,200	604,800			75.00	85	25,500	**630,300**
Check valves 36"	ea	1	48,000	48,000			24.00	85	2,040	**50,040**
Check valves 48"	ea	3	66,000	198,000			24.00	85	6,120	**204,120**
Check valves 60"	ea	3	108,000	324,000			30.00	85	7,650	**331,650**
Check valves 84"	ea	3	178,000	534,000			36.00	85	9,180	**543,180**
Concrete barrier walls (all in)	m3	825			250	206,250	8.00	75	495,000	**701,250**
Concrete basin walls (all in)	m3	900			225	202,500	8.00	75	540,000	**742,500**
Concrete elevated slabs (all in)	m3	850			250	212,500	10.00	75	637,500	**850,000**
Concrete for transformers and oil catch basin (allocation)	m3	150			250	37,500	10.00	75	112,500	**150,000**
Concrete slabs on grade (all in)	m3	5,100			200	1,020,000	4.00	75	1,530,000	**2,550,000**
Ductile iron cement pipe 12" diam. for fire water line	ft	3,000			100	300,000	0.60	95	171,000	**471,000**
Excavation and backfill for fire line, blowdown & make-up (using excavated material for backfill except for bedding)	m3	11,823					0.08	200	189,168	**189,168**
Excavation for PCCP pipe	m3	46,902					0.04	200	375,216	**375,216**
Fencing around transformers	m	40			30	1,200	1.00	75	3,000	**4,200**
Flange for PCCP joints 120"	ea	8			39,795	318,360	40.00	95	30,400	**348,760**
Flange for PCCP joints 30"	ea	41			2,260	92,660	16.00	95	62,320	**154,980**
Flange for PCCP joints 36"	ea	10			2,765	27,650	18.00	95	17,100	**44,750**
Flange for PCCP joints 48"	ea	6			5,000	30,000	20.00	95	11,400	**41,400**
Flange for PCCP joints 84"	ea	2			13,210	26,420	30.00	95	5,700	**32,120**
Flange for PCCP joints 96"	ea	8			15,080	120,640	35.00	95	26,600	**147,240**
Foundations for pipe racks and cable racks	m3	450			250	112,500	8.00	75	270,000	**382,500**
FRP flange 30"	ea	164			1,679	275,381	50.00	85	697,000	**972,381**
FRP flange 60"	ea	64			7,786	498,277	100.00	85	544,000	**1,042,277**
FRP flange 72"	ea	8			20,888	167,101	200.00	85	136,000	**303,101**
FRP flange 84"	ea	30			33,382	1,001,445	300.00	85	765,000	**1,766,445**
FRP pipe 72" diam.	ft	1,200			851	1,021,680	1.20	85	122,400	**1,144,080**
FRP pipe 84" diam.	ft	2,600			946	2,459,600	1.50	85	331,500	**2,791,100**
Harness clamp 120" c/w internal testable joint for PCCP pipe	ea	175			4,310	754,250	25.00	95	415,625	**1,169,875**
Harness clamp 48" & 36" c/w internal testable joint	ea	115			2,000	230,000	16.00	95	174,800	**404,800**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Harness clamp 84" c/w internal testable joint	ea	40			2,845	113,800	20.00	95	76,000	**189,800**
Harness clamp 96" c/w internal testable joint	ea	225			3,300	742,500	22.00	95	470,250	**1,212,750**
Joint for FRP pipe 72" diam.	ea	0			3,122	353	200.00	85	1,921	**2,274**
Joint for FRP pipe 84" diam.	ea	70			5,014	350,966	300.00	85	1,785,000	**2,135,966**
PCCP pipe 120" diam.	ft	2,550			1,285	3,276,750	3.50	95	847,875	**4,124,625**
PCCP pipe 36" dia. for blowdown	ft	500			160	80,000	0.80	95	38,000	**118,000**
PCCP pipe 48" dia. for make-up water line	ft	1,500			260	390,000	1.00	95	142,500	**532,500**
PCCP pipe 84" diam.	ft	700			562	393,400	1.50	95	99,750	**493,150**
PCCP pipe 96" diam.	ft	4,100			890	3,649,000	2.00	95	779,000	**4,428,000**
Riser (FRP pipe 30" diam X 40ft)	ea	41			14,603	598,739	100.00	85	348,500	**947,239**
Structural steel for barrier wall	t	105			2,500	262,500	15.00	105	165,375	**427,875**
Structural steel for building	t	145			2,500	363,625	20.00	105	305,445	**669,070**
CIVIL / STRUCTURAL / PIPING TOTAL				**8,921,600**		**21,841,722**			**15,396,647**	**46,159,969**
DEMOLITION										
Demolition of tank 305ft diam.	ea	4					4,000.00	100	1,600,000	**1,600,000**
DEMOLITION TOTAL				**0**		**0**			**1,600,000**	**1,600,000**
ELECTRICAL										
4.16 kv cabling feeding MCC's	m	3,000			75	225,000	0.40	85	102,000	**327,000**
4.16kV switchgear - 5 breakers	ea	1	280,000	280,000			200.00	85	17,000	**297,000**
480 volt cabling feeding MCC's	m	1,500			70	105,000	0.40	85	51,000	**156,000**
480V Switchgear - 1 breaker 3000A	ea	7	30,000	210,000			80.00	85	47,600	**257,600**
Allocation for automation and control	lot	1			1,000,000	1,000,000	10,000.00	85	850,000	**1,850,000**
Allocation for cable trays and duct banks	m	3,000			75	225,000	1.00	85	255,000	**480,000**
Allocation for lighting and lightning protection	lot	1			150,000	150,000	1,500.00	85	127,500	**277,500**
Dry Transformer 2MVA xxkV-480V	ea	7	100,000	700,000			100.00	85	59,500	**759,500**
Lighting & electrical services for pompous building	ea	3			20,000	60,000	250.00	85	63,750	**123,750**
Local feeder for 200 HP motor 460 V (up to MCC)	ea	10			15,000	150,000	140.00	85	119,000	**269,000**
Local feeder for 2000 HP motor 4160 V (up to MCC)	ea	2			40,000	80,000	160.00	85	27,200	**107,200**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Local feeder for 250 HP motor 460 V (up to MCC)	ea	31			18,000	558,000	150.00	85	395,250	**953,250**
Local feeder for 2800 HP motor 4160 V (up to MCC)	ea	3			45,000	135,000	175.00	85	44,625	**179,625**
Local feeder for 4000 HP motor 4160 V (up to MCC)	ea	3			50,000	150,000	200.00	85	51,000	**201,000**
Oil Transformer 10/13.3MVA xx-4.16kV	ea	3	190,000	570,000			150.00	85	38,250	**608,250**
Primary breaker(xxkV)	ea	6	45,000	270,000			60.00	85	30,600	**300,600**
Primary feed cabling (assumed 13.8 kv)	m	4,500			175	787,500	0.50	85	191,250	**978,750**
ELECTRICAL TOTAL				**2,030,000**		**3,625,500**			**2,470,525**	**8,126,025**
MECHANICAL										
Allocation for ventilation of buildings	ea	3	25,000	75,000			250.00	85	63,750	**138,750**
Cooling tower for unit 1 & 2	lot	1	8,218,200	8,218,200						**8,218,200**
Cooling tower for unit 5 & 6	lot	1	11,246,900	11,246,900						**11,246,900**
Cooling tower for unit 8	lot	1	5,735,200	5,735,200	--	--	--	--	--	**5,735,200**
Overhead crane 30 ton in (in pump house)	ea	3	75,000	225,000	--	--	100.00	85	25,500	**250,500**
Pump 4160 V 2000 HP	ea	2	1,020,000	2,040,000	--	--	500.00	85	85,000	**2,125,000**
Pump 4160 V 2800 HP	ea	3	1,360,000	4,080,000	--	--	600.00	85	153,000	**4,233,000**
Pump 4160 V 4000 HP	ea	3	1,600,000	4,800,000	--	--	800.00	85	204,000	**5,004,000**
MECHANICAL TOTAL	**--**	**--**	**--**	**36,420,300**	**--**	**0**	**--**	**--**	**531,250**	**36,951,550**

Appendix C. Net Present Cost Calculation—Haynes All Units

Project Year	Capital / Startup ($)	O & M ($)	Energy Penalty ($)			Total ($)	Annual Discount Factor	Present Value ($)
			Units 1 & 2	Units 5 & 6	Unit 8			
0	156,550,000	--	--	--		156,550,000	1	**156,550,000**
1	--	1,429,920	707,510	529,085	763,074	3,429,589	0.9346	**3,205,293**
2	--	1,458,518	748,757	559,931	807,561	3,574,768	0.8734	**3,122,202**
3	--	1,487,689	792,410	592,575	854,642	3,727,315	0.8163	**3,042,608**
4	--	1,517,443	838,608	627,122	904,467	3,887,639	0.7629	**2,965,880**
5	--	1,547,791	887,498	663,683	957,198	4,056,171	0.713	**2,892,050**
6	--	1,578,747	939,240	702,376	1,013,002	4,233,365	0.6663	**2,820,691**
7	--	1,610,322	993,997	743,324	1,072,060	4,419,704	0.6227	**2,752,150**
8	--	1,642,529	1,051,947	786,660	1,134,562	4,615,698	0.582	**2,686,336**
9	--	1,675,379	1,113,276	832,522	1,200,707	4,821,884	0.5439	**2,622,623**
10	--	1,708,887	1,178,180	881,059	1,270,708	5,038,833	0.5083	**2,561,239**
11	--	1,743,065	1,246,868	932,424	1,344,790	5,267,146	0.4751	**2,502,421**
12	--	2,114,852	1,319,560	986,785	1,423,191	5,844,387	0.444	**2,594,908**
13	--	2,157,149	1,396,490	1,044,314	1,506,163	6,104,116	0.415	**2,533,208**
14	--	2,200,292	1,477,906	1,105,198	1,593,973	6,377,368	0.3878	**2,473,143**
15	--	2,244,298	1,564,068	1,169,631	1,686,901	6,664,897	0.3624	**2,415,359**
16	--	2,289,183	1,655,253	1,237,820	1,785,248	6,967,504	0.3387	**2,359,894**
17	--	2,334,967	1,751,754	1,309,985	1,889,327	7,286,034	0.3166	**2,306,758**
18	--	2,381,666	1,853,881	1,386,357	1,999,475	7,621,380	0.2959	**2,255,166**
19	--	2,429,300	1,961,963	1,467,182	2,116,045	7,974,489	0.2765	**2,204,946**
20	--	2,477,886	2,076,345	1,552,719	2,239,410	8,346,359	0.2584	**2,156,699**
Total								**209,023,574**

Appendix D. Net Present Cost Calculation—Haynes Unit 8

Project year	Capital / Start-up ($)	O & M ($)	Energy Penalty ($)	Total ($)	Annual discount factor	Present value ($)
			Unit 8			
0	46,950,000	--		46,950,000	1	**46,950,000**
1	--	438,000	763,074	1,201,074	0.9346	**1,122,523**
2	--	446,760	807,561	1,254,321	0.8734	**1,095,524**
3	--	455,695	854,642	1,310,337	0.8163	**1,069,628**
4	--	464,809	904,467	1,369,276	0.7629	**1,044,621**
5	--	474,105	957,198	1,431,303	0.713	**1,020,519**
6	--	483,587	1,013,002	1,496,590	0.6663	**997,178**
7	--	493,259	1,072,060	1,565,320	0.6227	**974,725**
8	--	503,124	1,134,562	1,637,686	0.582	**953,133**
9	--	513,187	1,200,707	1,713,893	0.5439	**932,187**
10	--	523,451	1,270,708	1,794,158	0.5083	**911,971**
11	--	533,920	1,344,790	1,878,710	0.4751	**892,575**
12	--	647,802	1,423,191	2,070,993	0.444	**919,521**
13	--	660,758	1,506,163	2,166,921	0.415	**899,272**
14	--	673,973	1,593,973	2,267,946	0.3878	**879,509**
15	--	687,453	1,686,901	2,374,354	0.3624	**860,466**
16	--	701,202	1,785,248	2,486,449	0.3387	**842,160**
17	--	715,226	1,889,327	2,604,553	0.3166	**824,602**
18	--	729,530	1,999,475	2,729,005	0.2959	**807,513**
19	--	744,121	2,116,045	2,860,166	0.2765	**790,836**
20	--	759,003	2,239,410	2,998,413	0.2584	**774,790**
Total						**65,563,253**

G. HUNTINGTON BEACH GENERATING STATION

AES HUNTINGTON BEACH, LLC—HUNTINGTON BEACH, CA

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1.0 GENERAL SUMMARY

Retrofitting the existing once-through cooling system at Huntington Beach Generating Station (HBGS) with closed-cycle wet cooling towers is technically and logistically feasible based on this study's design criteria, and will reduce cooling water withdrawals from Los Cerritos Channel by approximately 95 percent. Impingement and entrainment impacts would be reduced by a similar proportion.

The preferred option selected for HBGS includes 4 conventional wet cooling towers (without plume abatement), with individual cells arranged in an inline configuration to accommodate limited space at the site. A desalination facility has been proposed for HBGS and would be co--located on the existing property. This study assumes placement of the desalination plant will be the same as discussed in previous studies and reserves sufficient space for those facilities. Siting constraints and placement are discussed in Section 3.2.3.

Space limitations would appear to preclude plume-abated towers in the design if they were required to mitigate visual impacts. Initial capital costs for the towers would also increase by a factor of 2 or 3.

Construction-related shutdowns are estimated to take approximately 4 weeks per unit (concurrent), although HBGS is not expected to incur any financial loss as a result based on 2006 capacity utilization rates for all units.

The cooling tower configuration designed under the preferred option complies with all identified local use restrictions and includes necessary mitigation measures, where applicable.

1.1 COST

Initial capital and net present costs associated with installing and operating wet cooling towers at HBGS are summarized in Table G–1. Annualized costs based on 20-year average values for the various cost elements are summarized in Table G–2.

Table G–1. Cumulative Cost Summary

Cost category	Cost ($)	Cost per MWh (rated capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Total capital and start-up [a]	132,600,000	17.20	116
NPC_{20} [b]	160,400,000	20.80	141

[a] Includes all costs associated with the cooling tower construction and installation and shutdown loss, if any.
[b] NPC_{20} includes all capital costs, operation and maintenance costs, and energy penalty costs over 20 years discounted at 7 percent.

Table G–2. Annual Cost Summary

Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Capital and start-up	12,500,000	1.62	10.96
Operations and maintenance	900,000	0.12	0.79
Energy penalty	2,000,000	0.26	1.75
Total HBGS annual cost	**15,400,000**	**2.00**	**13.50**

1.2 ENVIRONMENTAL

Environmental changes associated with a cooling tower retrofit for HBGS are summarized in Table G–3 and discussed further in Section 3.4.

Table G–3. Environmental Summary

		Units 1 & 2	Units 3 & 4
Water use	Design intake volume (gpm)	168,000	168,000
	Cooling tower makeup water (gpm)	9,200	9,200
	Reduction from capacity	95%	95%
Energy efficiency [a]	Summer heat rate increase	1.59%	1.59%
	Summer energy penalty	2.76%	2.70%
	Annual heat rate increase	1.20%	1.20%
	Annual energy penalty	2.36%	2.31%
Direct air emissions [b]	PM_{10} emissions (tons/yr) (maximum capacity)	96.66	96.66
	PM_{10} emissions (tons/yr) (2006 capacity utilization)	17.93	10.84

[a] Reflects the comparative increase between once-through and wet cooling systems, but does not account for any operational changes to address the change in efficiency, such as increased fuel consumption (see Section 4.6).

[b] Reflects emissions from the cooling tower only; does not include any increase in stack emissions.

2.0 BACKGROUND

HBGS is a natural gas-fired steam electric generating facility located in the city of Huntington Beach, Orange County, owned and operated by AES Huntington Beach, LLC. The facility site occupies 83 acres of a 106-acre parcel along the Pacific Ocean, directly across the Pacific Coast Highway from Huntington State Beach. HBGS currently operates four steam generating units (Units 1−4); Unit 5 is a combustion turbine retired from service in 2002. (See Table G–4 and Figure G–1.)

Table G−4. General Information

Unit	In-service year	Rated capacity (MW)	2006 capacity utilization [a]	Condenser cooling water flow (gpm)
Unit 1	1958	215	20.4%	84,000
Unit 2	1958	215	16.7%	84,000
Unit 3	2003 [b]	225	11.6%	84,000
Unit 4	2003 [b]	225	10.8%	84,000
HBGS total		**880**	**12.9%**	**336,000**

[a] Quarterly Fuel and Energy Report—2006 (CEC 2006).
[b] Units 3 and 4 were retired in 1995 but re-entered service in 2003 following an emergency re-tool certification from the CEC following the 2001 energy crisis.

2.1 COOLING WATER SYSTEM

HBGS operates one cooling water intake structure (CWIS) to provide condenser cooling water to all four steam generating units. (Figure G–2). Once-through cooling water is combined with low volume wastes generated by HBGS and discharged through a submerged structure approximately 1,200 feet offshore in the Pacific Ocean. Surface water withdrawals and discharges are regulated by NPDES Permit CA0001163 as implemented by Santa Ana Regional Water Quality Control Board (SARWQCB) Order R8-2006-0011.

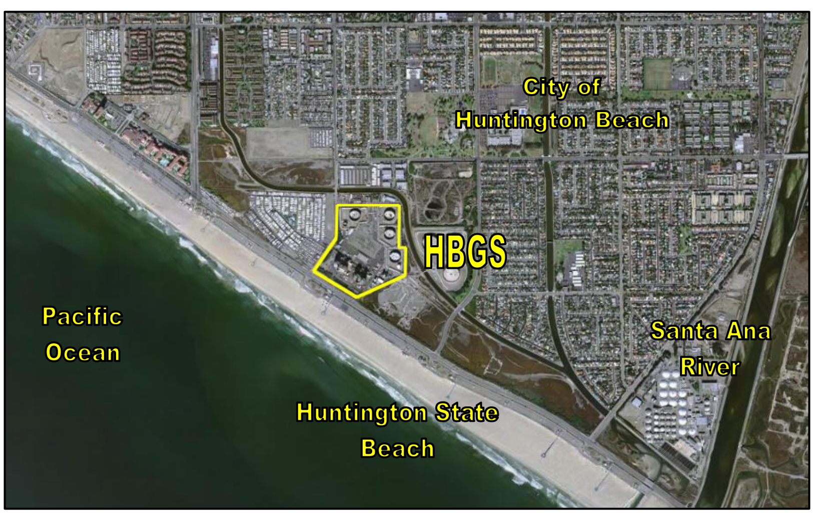

Figure G−1. General Vicinity of Huntington Beach Generating Station

Figure G–2. Site View

One CWIS serves all four steam units at HBGS. Water is withdrawn through a submerged conduit extending approximately 1,500 feet offshore in the Pacific Ocean and terminating at an approximate depth of 17 feet. The submerged end of the conduit is fitted with a velocity cap to minimize the entrainment of motile fish into the system by converting the vertical flow to a lateral flow, thus triggering a flight response from fish.

The onshore portion of the intake consists of four 11-foot wide screen bays (one for each unit), each fitted with a stationary screen and vertical traveling screen. Vertical traveling screens are fitted with 3 mesh panels and are typically rotated twice per shift for a period of 20 minutes. A high- pressure spray removes any debris or fish that have become impinged on the screen face. Captured debris is collected in a dumpster for disposal at a landfill. The approach velocity to the traveling screens ranges from 0.80 feet per second (fps) to 1.04 fps for each unit; through-screen velocities can be approximated by doubling the approach velocity.

Downstream of each traveling screen are two circulating water pumps. The six pumps used for Units 1–3 are rated at 42,000 gallons per minute (gpm), or 60 million gallons per day (mgd). The two pumps used for Unit 4 are rated at 46,300 gpm, or 67 mgd (AES 2005)

At maximum capacity, HBGS maintains a total pumping capacity rated at 514 mgd. On an annual basis, HBGS withdraws substantially less than its design capacity due to its low generating capacity utilization (12.9 percent for 2006). When in operation and generating the maximum load, HBGS can be expected to withdraw water from the Pacific Ocean at a rate approaching its maximum capacity.

2.2 SECTION 316(B) PERMIT COMPLIANCE

The CWIS currently in operation at HBGS uses a velocity cap to reduce the entrainment of motile fish through the system, although the caps are commonly thought of as impingement-reduction technologies because they target larger organisms. Velocity caps have been shown to reduce impingement rates when compared with a shoreline intake structure. Likewise, the location of the intake structure in a deep, offshore setting may contribute to lower rates of entrainment when compared with a shoreline intake if the near-shore environment is more biologically productive. This study did not evaluate the effectiveness of either measure.

The current order does not contain numeric or narrative limitations regarding impingement or entrainment resulting from CWIS operation, but does require impingement monitoring at the intake structure during heat treatment operations and at least once per month. Because the current orders were adopted following implementation of the Phase II rule but prior to the Second Circuit Court's decision and EPA's notice of suspension, the order contains a requirement to adhere to the rule's compliance schedule as well as a re-opener provision to incorporate any modifications necessary to comply with the performance standards.

The Phase II compliance schedule requirements consist of various data collection provisions and studies that were to be submitted in support of an eventual best technology available (BTA) determination made by the SARWQCB. Based on the record available for review, HBGS has been compliant with this permit requirement. No information from the SARWQCB is available indicating how it intends to proceed with the permit requirements in light of the changes to the Phase II rule.

As part of the Unit 3 and 4 emergency re-tool certification, the California Energy Commission (CEC) required HBGS to conduct an updated impingement and entrainment study to assess the affects of the increased intake volume on the surrounding aquatic environment (CEC 2001). A technical working group consisting of HBGS, the California Department of Fish and Game, National Marine Fisheries Service, and the US Fish and Wildlife service oversaw the study's design and provided comments on the final report. AES completed the study in April 2005.

3.0 WET COOLING SYSTEM RETROFIT

3.1 OVERVIEW

This study evaluates saltwater cooling towers as a retrofit option at HBGS, with the current source water (the Pacific Ocean) continuing to provide makeup water to the facility. Converting the existing once-through cooling system to wet cooling towers will reduce the facility's current intake capacity by approximately 95 percent; rates of impingement and entrainment will decline by a similar proportion. Use of reclaimed water was considered for HBGS but not analyzed in detail because the available volume cannot serve as a replacement for once-through cooling water. The proximity of available sources, however, may make reclaimed water an attractive alternative as makeup water for a wet cooling tower system when considering additional benefits its use may provide, such as avoidance of conflicts with effluent limitations or air emission standards.

A previous analysis of the use of alternative water sources in a wet cooling tower configuration was conducted by Powers Engineering in 2007. That study and other water sources are discussed in Section 3.4.4.

The wet cooling towers' configuration—their size, arrangement, and location—was based on best professional judgment (BPJ) using the criteria outlined in Chapter 5 and designed to meet the performance benchmarks in the most cost-effective manner. Information not available to this study that offers a more complete facility characterization may lead to different conclusions regarding the cooling towers' physical configuration.

This study developed a conceptual design of wet cooling towers sufficient to meet each active generating unit's cooling demand at its rated output during peak climate conditions and configured to allow for the construction of the proposed desalination facility at the site. Cost estimates are based on vendor quotes developed using the available information and the various design constraints identified at HBGS.

The overall practicality of retrofitting both units at HBGS will require an evaluation of factors outside the scope of this study, such as each unit's age and efficiency and its role in the overall reliability of electricity production and transmission in California, particularly the Los Angeles and San Diego regions.

3.2 DESIGN BASIS

3.2.1 CONDENSER SPECIFICATIONS

For this study, the wet cooling tower conceptual design selected for HBGS is based on the assumption that the condenser flow rate and thermal load to each will remain unchanged from the current system. Although no provision is included to re-optimize the condenser performance for service with a cooling tower, some modifications to the condenser (tube sheet and water box reinforcement) may be necessary to handle the increased water pressures that will result from the increased total pump head required to raise water to the cooling tower riser elevation. The practicality and difficulty of these modifications are dependent on each unit's age and configuration but are assumed to be feasible at HBGS. Condenser water boxes for both units are located at grade level and appear to be readily accessible. Additional costs for condenser modifications are included in the discussion of capital expenditures (Section 4.3).

Information provided by HBGS was largely used as the basis for the cooling tower design. In some cases, the data were incomplete or conflicted with values obtained from other sources. Some information and assumptions used in this study were obtained from a wet cooling tower analysis prepared by Sargent and Lundy, LLC in 2006. Where possible, questionable values were verified or corrected using other known information about the condenser.

For example, the condenser specification data sheets provided by AES did not contain information detailing the total surface area or heat transfer coefficients for the condenser tubes. In lieu of this information, a replacement value was calculated based on other known characteristics about the system (e.g., design inlet temperature, condenser rise, thermal load, tube material, etc.) using Heat Exchange Institute guidelines (HEI 2007). The resulting calculation is referred to as the "U-A" value and is substituted into the relevant equations as necessary.

Parameters used in the development of the cooling tower design are summarized in Table G–5.

Table G–5. Condenser Design Specifications

	Units 1 & 2	Units 3 & 4
Thermal load (MMBTU/hr)	950	950
Surface area (ft^2)	NA	NA
Condenser flow rate (gpm)	84,000	84,000
Tube material	NA	NA
Heat transfer coefficient (U_d)	NA	NA
"U-A" value (BTU/hr·°F)	~82,600,000	~82,600,000
Cleanliness factor	0.85	0.85
Inlet temperature (°F)	63	63
Temperature rise (°F)	22.63	22.63
Steam condensate temperature (°F)	92.7	92.7
Turbine exhaust pressure (in. HgA)	1.55	1.55

3.2.2 AMBIENT ENVIRONMENTAL CONDITIONS

HBGS is located in Orange County along the Pacific Ocean. Cooling water is withdrawn at the from a submerged offshore intake structure. Inlet temperature data specific to HBGS were not provided by AES. As a substitute, monthly temperature data was obtained from the National Oceanographic and Atmospheric Administration (NOAA) *Coastal Water Temperature Guide—Dana Point, CA* (NOAA 2007).

The wet bulb temperature used to develop the overall cooling tower design in this study was obtained from the Sargent and Lundy report, which selected a one percent ambient wet bulb temperature of 69.5° F based on climate data for the Marine Corps Air Station in Tustin (Sargent and Lundy 2006). A 12° F approach temperature was selected based on the site configuration and vendor input. At the design wet bulb and approach temperatures, the cooling towers will yield "cold" water at 81.5° F.

Monthly maximum wet bulb temperatures used in the development of energy penalty estimates in Section 4.6 were obtained from National Climatic Data Center (NCDC) climate normals for Newport Beach Harbor in Newport Beach, California (NCDC 2006). Climate data used in this analysis are summarized in Table G–6.

Table G–6. Surface Water and Ambient Wet Bulb Temperatures

	Surface (°F)	Ambient wet bulb (°F)
January	57.2	52.3
February	58.3	54.1
March	59.5	55.7
April	61.1	58.7
May	61.4	63.7
June	62.6	66.3
July	64.1	68.4
August	63.9	69.5
September	62.0	66.5
October	60.9	62.0
November	59.3	58.6
December	58.7	53.5

3.2.3 LOCAL USE RESTRICTIONS

3.2.3.1 NOISE

Industrial development at HBGS is regulated by the city of Huntington Beach General Plan and the Coastal Element that serves as the city's Local Coastal Program (LCP). The facility area is designated as General Industrial. According to the city's municipal code, HBGS is located in Noise Zone 4, which restricts external noise levels to 70 dBA at anytime of the day. Due to the proximity of residential areas (approximately 300 feet from the property's western boundary at some points), this study selected a noise limitation of 60 dBA measured at 800 feet when designing the wet cooling towers. Compliance with this restriction does not require noise abatement measures such as low noise fans or barrier walls.

3.2.3.2 BUILDING HEIGHT

The developed portion of HBGS is located within the General Industrial zone according to the city's General Plan. This zone is dedicated to industrial uses and establishes a building height restriction of 40 feet although the facility is designated as a pre-existing use and may be able to obtain a greater height limit. The height of the wet cooling towers designed for HBGS, from grade level to the top of the fan deck, is 39 feet and complies with the existing height limit.

3.2.3.3 PLUME ABATEMENT

Local zoning ordinances do not contain any specific criteria for addressing impacts associated with a wet cooling tower plume. Using the selection criteria for this study, plume abatement measures were not considered for HBGS; all towers are a conventional design. The plume from wet cooling towers at HBGS is not expected to adversely impact nearby infrastructure Community standards for assessing the visual impact associated with a cooling tower plume cannot be determined within the scope of this study.

The proximity of nearby residential and coastal recreational and protected areas, and the potential visual impact on these resources, may require plume abatement measures. CEC siting guidelines and Coastal Act provisions evaluate the total size and persistence of a visual plume with respect to aesthetic standards for coastal resources; significant visual changes resulting from a persistent plume would likely be subject to additional controls.

Depending on the scope of the proposed desalination facility to be co-located at the site, plume-abated towers may face greater obstacles with respect to placement; these towers are taller than a conventional design and may conflict with permitted building height restrictions. If required, plume-abated towers would increase the initial capital cost by 2−3 times that of conventional towers.

3.2.3.4 DRIFT AND PARTICULATE EMISSIONS

Drift elimination measures that are considered best available control technology (BACT) are required for all cooling towers evaluated in this study, regardless of their location. State-of-the-art drift eliminators are included for each cooling tower cell at HBGS, with an accepted efficiency of 0.0005 percent. Because cooling tower PM_{10} emissions are a function of the drift rate, drift eliminators are also considered BACT for PM_{10} emissions from wet cooling towers. This efficiency can be verified by a proper in situ test, which accounts for site-specific climate, water, and operating conditions. Testing based on the Cooling Tower Institute's Isokinetic Drift Test Code is required at initial start-up on only one representative cell of each tower for an approximate cost of $60,000 per test, or approximately $240,000 for all four cooling towers at HBGS (CTI 1994). This cost is not itemized in the final analysis and is instead included as part of the indirect cost estimate (Section 4.3).

3.2.3.5 FACILITY CONFIGURATION AND AREA CONSTRAINTS

The existing site's configuration, as currently understood, allows for the placement of wet cooling towers without significant disruption to other facility operations. Alternative configurations are limited by the future construction of a desalination facility at the site. Available areas are shown in Figure G–3.

Area 1 and Area 2 are currently occupied by three empty fuel tanks. Both areas have been reserved for the desalination facility and are unavailable for wet cooling towers.

Area 3 is an L-shaped parcel bordering the northern and northeastern property lines. Although use of this area places the cooling towers at their greatest possible distance from the generating units, it is the only sufficiently-sized area available unless the switchyard was relocated. This study did not consider using the switchyard area because of the complexity and cost associated with relocation.

Figure G–3. Cooling Tower Siting Locations

3.3 CONCEPTUAL DESIGN

Based on the design constraints discussed above two wet cooling tower complexes, each consisting of two towers, were selected to replace the current once-through cooling system at HBGS, for a total of four towers. Each tower complex will operate independently and be dedicated to one unit pair (Tower Complex 1 serves Units 1 and 2; Tower Complex 2 serves Units 3 and 4). Separate pump houses are constructed for each complex. Each tower is configured in a multicell, inline arrangement.

3.3.1 SIZE

Each tower is constructed over a concrete collection basin 4 feet deep. The basin is larger than the tower structure's footprint, extending an additional 2 feet in each direction. The concrete used for construction is suitable for saltwater applications. The principal tower material is fiberglass reinforced plastic (FRP), with stainless steel fittings. These materials are more resistant to the higher corrosive effects of saltwater.

The size of each tower is primarily based on the thermal load rejected to the tower by the surface condenser and a 12° F approach to the ambient wet bulb temperature. Flow rates through each condenser remain unchanged.

General characteristics of the wet cooling towers selected for HBGS are summarized in Table G–7.

Table G–7. Wet Cooling Tower Design

	Tower Complex 1 (Units 1 & 2)	Tower Complex 2 (Units 3 & 4)
Thermal load (MMBTU/hr)	1,900	1,900
Circulating flow (gpm)	168,000	168,000
Number of cells	14	14
Tower type	Mechanical draft	Mechanical draft
Flow orientation	Counterflow	Counterflow
Fill type	Modular splash	Modular splash
Arrangement	Inline	Inline
Primary tower material	FRP	FRP
Tower dimensions (l x w x h) (ft) [a]	378 x 48 x 39	378 x 48 x 39
Tower footprint with basin (l x w) (ft) [a]	382 x 52	382 x 52

[a]Two individual towers with these dimensions form each cooling tower complex.

3.3.2 LOCATION

The initial site selection for each tower was based on the desire to locate each tower as close as possible to the respective generating units to minimize the supply and return pipe distances and any increases in total pump head and brake horsepower. At HBGS, the linear distance between the generating units and towers is large (approximately 4,000 feet) but does not present any significant challenges for placing the supply and return pipelines (Figure G–4).

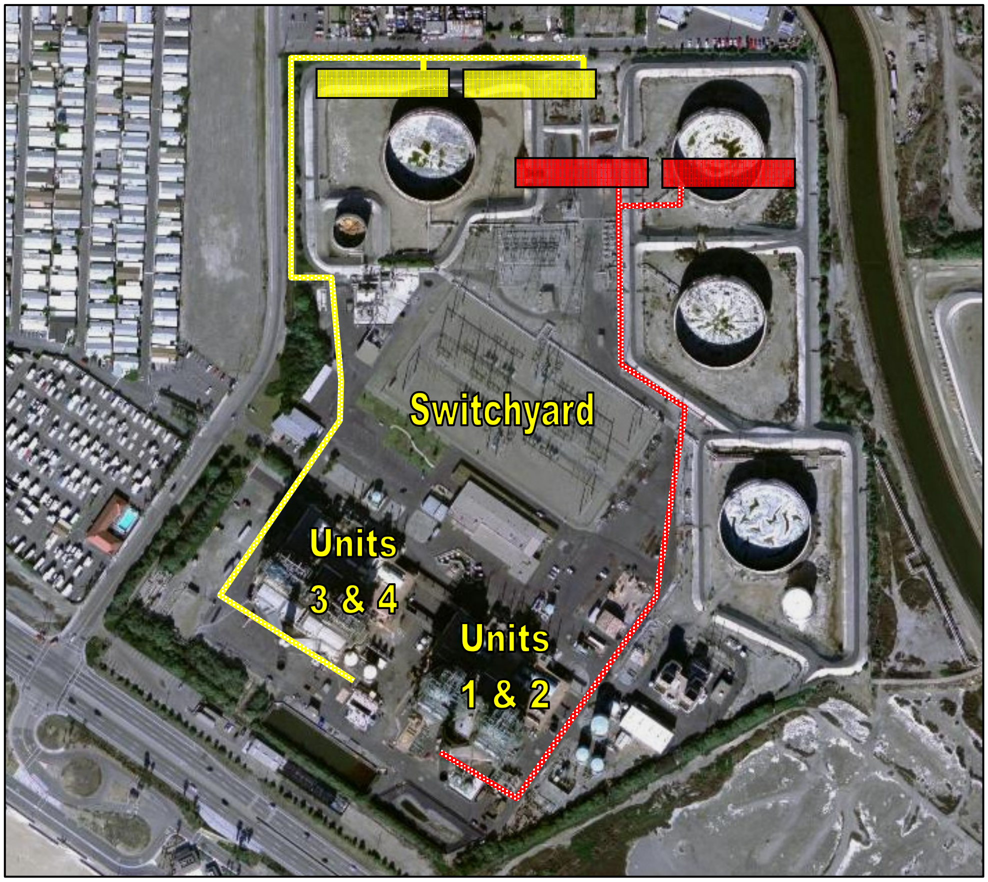

Figure G–4. Cooling Tower Locations

3.3.3 PIPING

The main supply and return pipelines to and from both towers will be located underground and made of prestressed concrete cylinder pipe (PCCP) suitable for saltwater applications. These pipes are 72 inches in diameter. The distance between the towers and their respective generating units requires roughly 15,000 feet of PCCP for the supply and return lines. Pipes connecting the condensers to the supply and return lines are made of FRP and placed above ground on pipe racks. Above ground placement avoids the potential disruption that may be caused by excavation in and around the power block. The condensers at HBGS are all located at grade level, enabling a relatively straightforward connection.

All riser piping (extending from the foot of the tower to the level of water distribution) is constructed of FRP.

Potential interference with underground obstacles and infrastructure is a concern, particularly at existing sites that are several decades old and have been substantially modified or rebuilt in the interim. Avoidance of these obstacles is considered to the degree practical in this study. Associated costs are included in the contingency estimate and are generally higher than similar estimates for new facilities (Section 4.3).

Appendix B details the total quantity of each pipe size and type for HBGS.

3.3.4 FANS AND PUMPS

Each tower cell uses an independent single-speed fan. The fan size and motor power are the same for each cell in each tower.

This analysis includes new pumps to circulate water between the condensers and cooling towers. Pumps are sized according to the flow rate for each tower, the relative distance between the towers and condensers, and the total head required to deliver water to the top of each cooling tower riser. A separate, multilevel pump house is constructed for each tower and sized to accommodate the motor control centers (MCCs) and appropriate electrical switchgear. The electrical installation includes all necessary transformers, cabling, cable trays, lighting, and lightning protection. A 30-ton overhead crane is also included to allow for pump servicing.

Fan and pump characteristics associated with wet cooling towers at HBGS are summarized in Table G–8. The net electrical demand of fans and new pumps is discussed further as part of the energy penalty analysis in Section 4.6.

Table G–8. Cooling Tower Fans and Pumps

		Tower Complex 1 (Units 1 & 2)	Tower Complex 2 (Units 3 & 4)
Fans	Number	14	14
	Type	Single speed	Single speed
	Efficiency	0.95	0.95
	Motor power (hp)	211	211
Pumps	Number	4	4
	Type	50 % recirculating Mixed flow Suspended bowl Vertical	50 % recirculating Mixed flow Suspended bowl Vertical
	Efficiency	0.88	0.88
	Motor power (hp)	1,295	1,295

3.4 ENVIRONMENTAL EFFECTS

Converting the existing once-through cooling system at HBGS to wet cooling towers will significantly reduce the intake of seawater from the Pacific Ocean and will presumably reduce impingement and entrainment by a similar proportion. Because closed-cycle systems will almost always result in condenser cooling water temperatures higher than those found in a comparable once-through system, wet towers will increase the operating heat rates at all four of HBGS's steam units, thereby decreasing the facility's overall efficiency. Additional power will also be consumed by the tower fans and circulating pumps.

Depending on how HBGS chooses to address this change in efficiency, total stack emissions may increase for pollutants such as $PM_{10,}$ $SO_{x,}$ and NO_x, and may require additional control measures (e.g., electrostatic precipitation, flue gas desulfurization, and selective catalytic reduction) or the purchase of emission credits to meet air quality regulations. The availability of emission reduction credits (ERCs) and their associated cost was not evaluated as part of this study, but may limit the air emission compliance options available to HBGS.

No control measures are currently available for CO_2 emissions, which will increase, on a per-kWh basis, by the same proportion as any change in the heat rate. The towers themselves will constitute an additional source of PM_{10} emissions, the annual mass of which will largely depend on the capacity utilization rate for the generating units served by each tower.

If HBGS retains its NPDES permit to discharge wastewater to the Pacific Ocean with a wet cooling tower system, it may have to address revised effluent limitations resulting from the substantial change in the discharge quantity and characteristics. Thermal impacts from the current once-through system, if any, will be minimized with wet cooling towers.

3.4.1 AIR EMISSIONS

HBGS is located in the South Coast air basin. Air emissions are permitted by the South Coast Air Quality Management District (SCAQMD) (Facility ID 115389).

Drift volumes are expected to be within the range of 0.5 gallons for every 100,000 gallons of circulating water in the towers. At HBGS, this corresponds to a rate of approximately 1.7 gpm based on the maximum combined flow in all four towers. Salt drift deposition is not expected to a concern at HBGS with wet cooling towers. Their location is generally downwind from sensitive structures and more than 1,500 feet from the nearest potentially affected residences. Any drift would be expected to settle out within than distance.

Total PM_{10} emissions from the HBGS cooling towers are a function of the number of hours in operation, overall water quality in the tower, and evaporation rate of drift droplets prior to deposition on the ground. Makeup water at HBGS will be obtained from the same source currently used for once-through cooling water (Pacific Ocean). At 1.5 cycles of concentration and assuming an initial TDS value of 35 parts per thousand (ppt), the water within the cooling towers will reach a maximum TDS level of roughly 53 ppt. Any drift droplets exiting the tower will have the same TDS concentration.

The cumulative mass emission of PM_{10} from HBGS will increase as a result of the direct emissions from the cooling towers themselves. Stack emissions of PM_{10}, as well as SO_x, $NO_{x,}$ and other pollutants, will increase due to the drop in fuel efficiency, although the cumulative increase will depend on actual operations and emission control technologies currently in use. Maximum drift and PM_{10} emissions from the cooling towers are summarized in Table G–9.[1]

[1] This is a conservative estimate that assumes all dissolved solids present in drift droplets will be converted to PM_{10}. Studies suggest this may overestimate actual emission profiles for saltwater cooling towers (Chapter 4).

Data summarizing the total facility emissions for these pollutants in 2005 are presented in Table G–10 (CARB 2005). In 2005, HBGS operated at an annual capacity utilization rate of 20.25 percent. Using this rate, the additional PM_{10} emissions from the cooling towers would increase the facility total by approximately 39 tons/year, or 99 percent.[2]

Table G–9. Full Load Drift and Particulate Estimates

	PM_{10} (lbs/hr)	PM_{10} (tons/year)	Drift (gpm)	Drift (lbs/hr)
Tower Complex 1	22	97	0.8	420
Tower Complex 2	22	97	0.8	420
Total HBGS PM_{10} and drift emissions	**44**	**194**	**1.6**	**840**

Table G–10. 2005 Emissions of SO_x, NO_x, PM_{10}

Pollutant	Tons/year
NO_x	71.3
SO_x	7.2
PM_{10}	40.6

3.4.2 MAKEUP WATER

The volume of makeup water required by both cooling towers at HBGS is the sum of evaporative loss and the blowdown volume required to maintain the circulating water in each tower at the design TDS concentration. Drift expelled from the towers represents an insignificant volume by comparison and is accounted for by rounding up evaporative loss estimates. Makeup water volumes are based on design conditions, and may fluctuate seasonally depending on climate conditions and facility operations. Wet cooling towers will reduce once-through cooling water withdrawals from the Pacific Ocean by approximately 95 percent over the current design intake capacity.

Table G–11. Makeup Water Demand

	Tower circulating flow (gpm)	Evaporation (gpm)	Blowdown (gpm)	Total makeup water (gpm)
Tower Complex 1	168,000	3,200	6,200	**9,400**
Tower Complex 2	168,000	3,200	6,200	**9,400**
Total HBGS makeup water demand	**336,000**	**6,400**	**12,400**	**18,800**

One circulating water pump, rated at 84,000 gpm, which is currently used to provide once-through cooling water to the facility, will be retained in a wet cooling system to provide makeup water to each cooling tower. The retained pump's capacity exceeds the makeup demand by approximately 65,000 gpm. Any excess capacity will be routed through a bypass conduit and returned to the wet well at a point located behind the intake screens. Recirculating the excess capacity in this manner reduces additional cost that would be incurred if new pumps were required while maintaining the desired flow reduction. The intake of new water, measured at the

[2] 2006 emission data are not currently available from the Air Resources Board website. For consistency, the comparative increase in PM_{10} emissions estimated here is based on the 2005 HBGS capacity utilization rate instead of the 2006 rate presented in Table G-4. All other calculations in this chapter use the 2006 value.

intake screens, will be equal to the cooling towers' makeup water demand. Figure G–5 presents a schematic of this configuration.

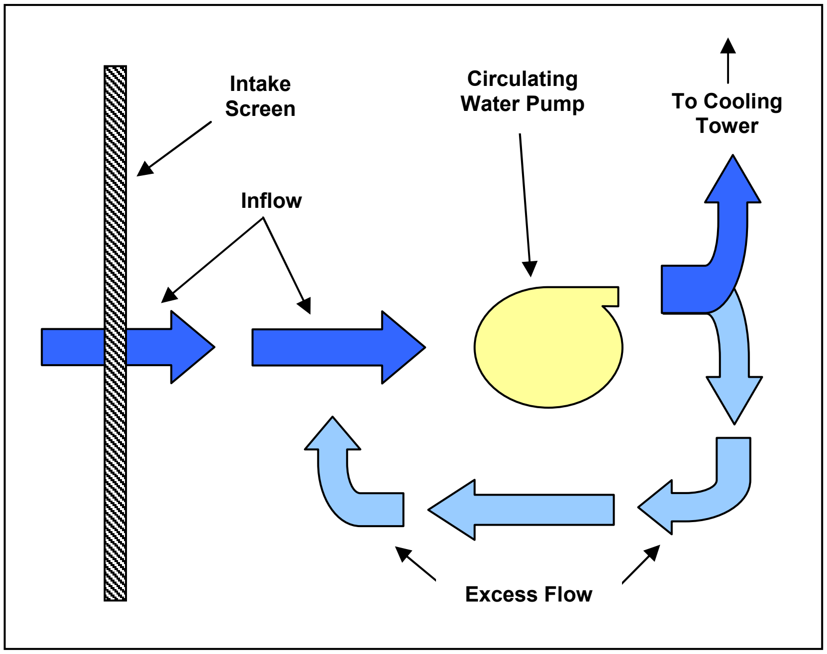

Figure G–5. Schematic of Intake Pump Configuration

The existing once-through cooling system at HBGS does not treat water withdrawn from the Pacific Ocean with the exception of screening for debris and larger organisms and periodic chlorination to control biofouling in the condenser tubes. Heat treatments are also periodically used to control mussel growth on pipes and condenser tubes by raising the temperature of the circulating water to 122º F. Conversion to a wet cooling tower system will not interfere with chlorination or heat treatment operations.

Makeup water will continue to be withdrawn from the Pacific Ocean.

The wet cooling tower system proposed for HBGS includes water treatment for standard operational measures, i.e., corrosion inhibitors, biocides, and anti-scaling agents. An allowance for these additional chemical treatments is included in annual O&M costs. It is assumed that the current once-through cooling water quality will be acceptable for use in a seawater cooling tower (with continued screening and chlorination) and will not require any pretreatment to enable its use.

3.4.3 NPDES PERMIT COMPLIANCE

At maximum operation, wet cooling towers at HBGS will result in an effluent discharge of approximately 17 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, floor drain wastes, and cleaning wastes. These low volume wastes may add an additional 1.5 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, HBGS will be required to modify its existing individual wastewater discharge (NPDES) permit.

Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0001163 as implemented by SARWQCB Order R82006-0011. All once-through cooling water and process wastewaters are discharged through a submerged outfall extending approximately 1,200 feet offshore into the Pacific Ocean. The existing order contains effluent limitations based on the 2005 Ocean Plan and the 1972 Thermal Plan.

HBGS will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities (40 CFR 423.13(d)(1)). These ELGs set numeric limitations for chromium and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity). Because ELGs are technology-based limitations, mixing zones or dilution factors are not applicable when determining compliance; limits must be met at the point of discharge from the cooling tower prior to commingling with any other waste stream. ELGs for cooling tower blowdown target priority pollutants that are contributed by maintenance chemicals and do not apply when limits may be exceeded as a result of background concentrations or other sources. Further discussion can be found in Chapter 4, Section 3.6.

Conversion to wet cooling towers will alter the volume and composition of a facility's wastewater discharge because wet towers concentrate certain pollutants in the effluent waste stream. The cooling towers designed for HBGS operate at 1.5 cycles of concentration, i.e., the blowdown discharge will contain a dissolved solids concentration 50 percent higher than the makeup water.

Changes to discharge composition may affect compliance with water quality objectives included in the Ocean Plan. If compliance with these objectives becomes problematic, alternative treatment or discharge methods may be necessary. Compliance may be achieved by altering the discharge configuration in such a way as to increase dilution (e.g., diffuser ports), or by seeking a mixing zone and dilution credits as permissible under the Ocean Plan. Alternately, some low volume waste streams (e.g., boiler blowdown, laboratory drains) may be diverted, with necessary permits, for treatment at a POTW.

If more pollutant-specific treatment methods, such as filtration or precipitation technologies, become necessary to meet WQBELs, the initial capital cost may range from $2 to $5.50 per 1,000 gallons of treatment capacity, with annual costs of approximately $0.5 per gallon of capacity, depending on the method of treatment (FRTR 2002). Hazardous material disposal fees and permits would further increase costs.

This evaluation did not include alternative discharge or effluent treatment measures in the conceptual design because the variables used to determine final WQBELs, which would be used to determine the type and scope of the desired compliance method, cannot be quantified here. Likewise, the final cost evaluation (Section 4.0) does not include any allowance for these possibilities.

Thermal discharge standards are based on narrative criteria established for coastal discharges under the Thermal Plan, which requires existing discharges of elevated-temperature wastes to comply with effluent limitations necessary to assure the protection of designated beneficial uses. The SARWQCB has implemented this provision in Order R8-2006-0011 by establishing a maximum discharge temperature of that may not exceed the receiving water's natural temperature by more than 30º F during normal operations (SARWQCB 2006). No information was available to review HBGS's compliance with this requirement. Because cooling tower blowdown will be taken from the "cold" side of the tower, conversion to a wet cooling system will significantly reduce the discharge temperature (to less than 81º F) and the size of any related thermal plume in the receiving water.

3.4.4 RECLAIMED WATER

Reclaimed or alternative water sources used in conjunction with wet cooling towers could eliminate all surface water withdrawals at HBGS. Doing so would completely eliminate impingement and entrainment concerns, and might enable the facility to avoid possible effluent quality and permit compliance issues, depending on the quality of reclaimed water available for use. In addition, wet cooling towers using reclaimed water would be expected to have lower PM_{10} emissions due to lower TDS levels. The California State Water Resources Control Board (SWRCB), in 1975, issued a policy statement requiring the consideration of alternative cooling methods in new power plants, including reclaimed water, over the use of freshwater (SWRCB 1975). There is no similar policy regarding marine waters, but the clear preference of state agencies is to encourage alternative cooling methods, including reclaimed water, wherever possible.

The present volume of available reclaimed water within a 15-mile radius of HBGS (62 mgd) does not meet the current once-through cooling demand; thus, reclaimed water is only applicable as a source of makeup water for a wet cooling tower system. This study did not pursue a detailed investigation of reclaimed water's use because the conversion of HBGS's once-through cooling system to saltwater cooling towers meets the performance benchmarks for impingement and entrainment impact reductions discussed in the 2006 California Ocean Protection Council (OPC) Resolution on Once-Through Cooling Water (see Chapter 1).

To be acceptable for use as makeup water in cooling towers, reclaimed water must meet tertiary treatment and disinfection standards under California Code of Regulations (CCR) Title 22. If the reclaimed water is not treated to the required levels, HBGS would be required to arrange for sufficient treatment, either onsite or at the source facility, prior to its use in the cooling towers.

Two alternative water sources were identified within a 15-mile radius of HBGS, with a combined discharge capacity of 62 mgd. Figure G–6 shows the relative locations of these facilities to HBGS.

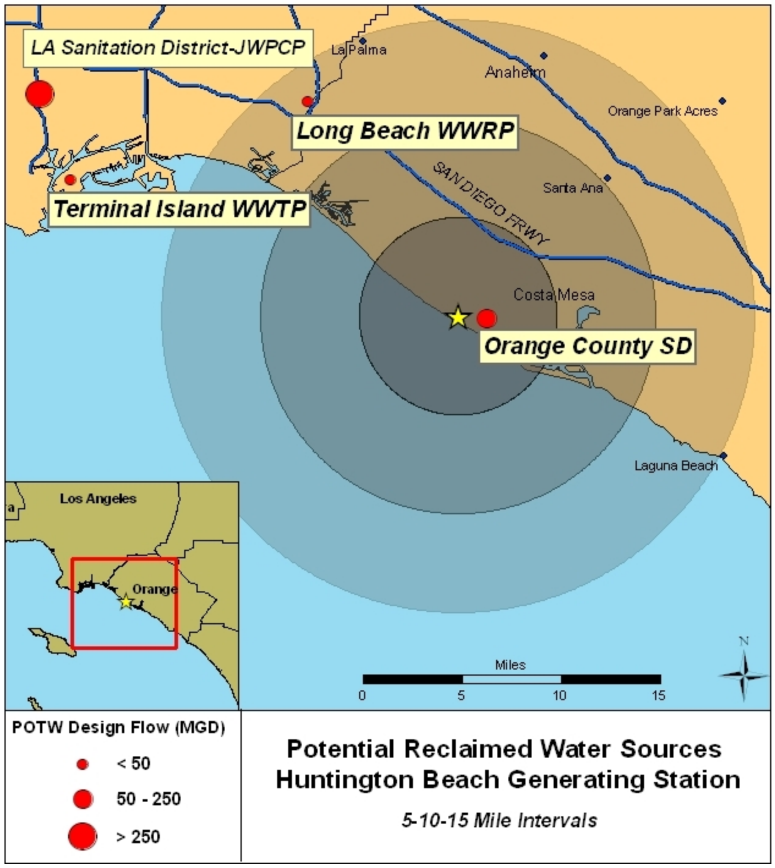

Figure G–6. Reclaimed Water Sources

- *Orange County Sanitation District (OCSD)—Huntington Beach*
  Discharge volume: 232 mgd
  Distance: 2 miles E
  Treatment level: Secondary

  The OCSD discharges secondary treated effluent from two POTWs (Fountain Valley and Huntington Beach) through a combined outfall to the Pacific Ocean. Sufficient capacity exists to supply the full makeup water demand for freshwater towers at HBGS (10 to 12 mgd), although HBGS would be required to provide treatment to tertiary standards prior to use in a cooling tower

- *Long Beach Water Reclamation Plant—Long Beach*
  Discharge volume: 20 mgd
  Distance: 12 miles NW
  Treatment level: Tertiary

  Approximately 25 percent is currently used for irrigation projects in the vicinity. The remaining capacity could supply the makeup water demand for freshwater cooling towers at HBGS.

Powers Engineering prepared an assessment of the cost and feasibility of using either of these sources to supply makeup water to wet cooling towers at HBGS. Water from the Long Beach facility would have to be purchased at a price of approximately $1.30/1,000 gallons, or up to $15,600 per day based on the maximum usage of the four cooling towers. A lower capacity utilization rate (HBGS operated at 12.9 percent in 2006) would require proportionally less water at a lower total cost. The transmission pipeline from Long Beach would be approximately 12 miles long and sized to provide the required flow to HBGS. The Powers report estimates the installed cost of a 24-inch pipeline at $200 per linear foot, or $12.7 million (Powers 2007).[3]

The volume of water discharged from the OCSD ocean outfall (approximately 230 mgd) is more than sufficient to meet the needs of freshwater cooling towers at HBGS and would not have to be purchased from the sanitation district. This water is not treated to tertiary standards, however, and would require some measure of treatment prior to use in a wet cooling tower. The Powers report estimates the initial capital cost for a package treatment system sufficient to treat the freshwater makeup water demand of 12 mgd at $2 million. Installed pipe costs were not included (Powers 2007).

Based on data compiled for this study and others, the estimated installed cost of a 24-inch pipeline, sufficient to provide 12 mgd to HBGS, is $300 per linear foot, or approximately $1.6 million per mile. Costs may be higher if transmission lines must cross through heavily urbanized areas or intersect major infrastructure, such as freeways or flood control channels.

Regulatory concerns beyond the scope of this investigation, however, may make reclaimed water (as a makeup water source) comparable or preferable to marine water from the Pacific Ocean. Reclaimed water may enable HBGS to eliminate potential conflicts with water discharge limitations or reduce PM_{10} emissions from the cooling tower, which is a concern given the South Coast air basin's current nonattainment status.

At any facility where wet cooling towers are a feasible alternative, reclaimed water may be used as a makeup water source. The practicality of its use, however, depends on the overall cost, availability, and additional environmental benefit that may occur.

3.4.5 THERMAL EFFICIENCY

Wet cooling towers at HBGS will increase the condenser inlet water temperature by a range of 13 to 17° F above the surface water temperature, depending on the ambient wet bulb temperature at the time. The generating units at HBGS are designed to operate at the conditions described in Table G–12. The resulting monthly difference between once-through and wet cooling tower condenser inlet temperatures is described in Figure G–7.

[3] The Powers Engineering estimate is based on the U.S. EPA, 1999 Drinking Water Infrastructure Needs Study - Modeling the Cost of Infrastructure, EPA 816-R-01-005, February 2001, p. Appendix A-12. Costs are escalated to 2006 dollars.

Table G–12. Design Thermal Conditions

	Units 1 & 2	Units 3 & 4
Design backpressure (in. HgA)	1.55	1.55
Design water temperature (°F)	63	63
Turbine inlet temp (°F)	1,000	1,000
Turbine inlet pressure (psia)	2,150	2,150
Full load heat rate (BTU/kWh) [a]	9,750	9,500

[a] CEC 2006.

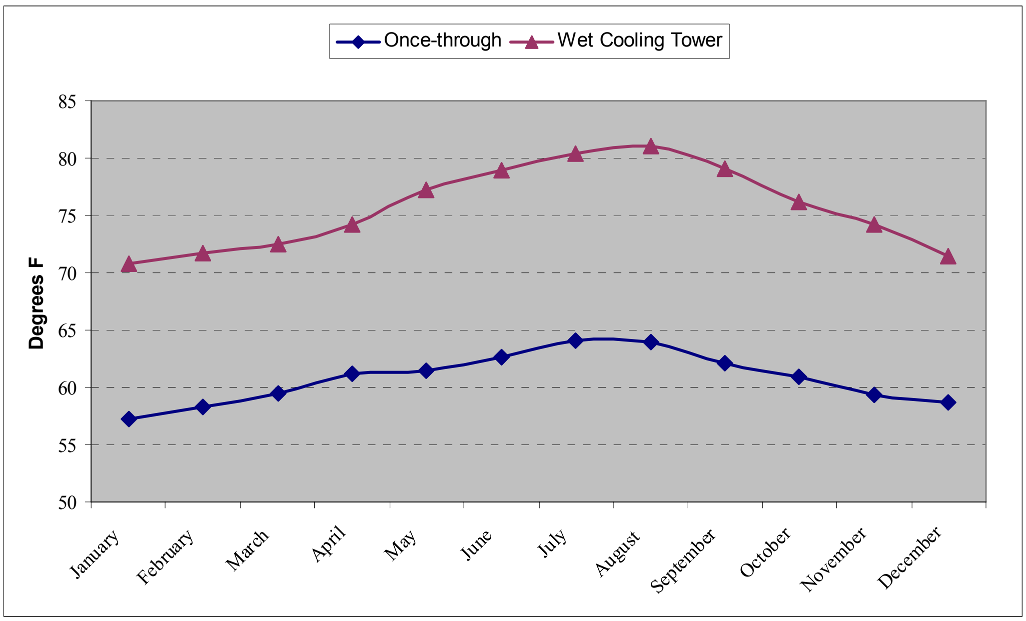

Figure G–7. Condenser Inlet Temperatures

Backpressures for the once-through and wet cooling tower configurations were calculated for each month using the design criteria described in the sections above and ambient climate data. In general, backpressures associated with the wet cooling tower were elevated by 0.6 to 1.0 inches HgA compared with the current once-through system (Figure G–8 and Figure G–10).

Heat rate adjustments were calculated by comparing the theoretical change in available energy that occurs at different turbine exhaust backpressures, assuming the thermal load and turbine inlet pressure remain constant, i.e., at the full load rating.[4] The relative change at different backpressures was compared with the value calculated for the design conditions (i.e., at design

[4] Changes in thermal efficiency estimated for HBGS are based on the design specifications provided by the facility. This may not reflect system modifications that might influence actual performance. In addition, the age of the units and the operating protocols used by HBGS might result in different calculations.

turbine inlet and exhaust backpressures) and plotted as a percentage of the full load operating heat rate (Table G–12) to develop estimated correction curves (Figure G–9 and Figure G–11).

The difference between the estimated once-through and closed-cycle heat rates for each month represents the approximate heat rate increase that would be expected when converting to wet cooling towers.

Table G–13 summarizes the annual average heat rate increase for each unit as well as the increase associated with the peak demand period of July-August-September. Monthly values were used to calculate the monetized value of these heat rate changes (Section 4.6.2). Month-by-month calculations are presented in Appendix A.

Table G–13. Summary of Estimated Heat Rate Increases

	Units 1 & 2	Units 3 & 4
Peak (July-August-September)	1.59%	1.59%
Annual average	1.20%	1.20%

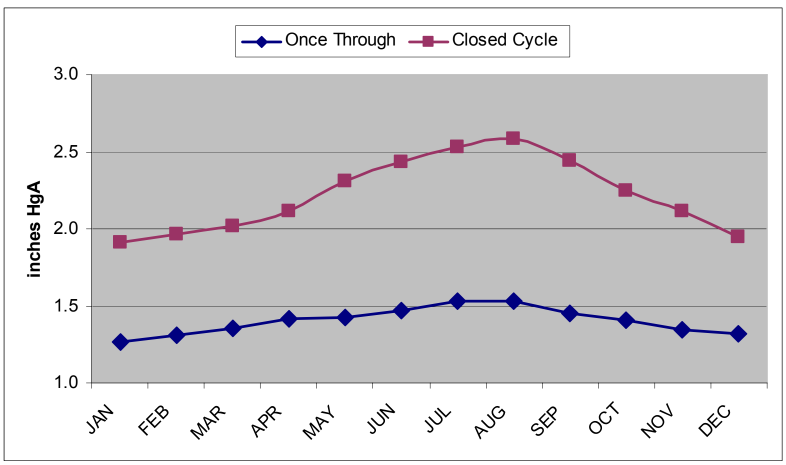

Figure G–8. Estimated Backpressures (Units 1 & 2)

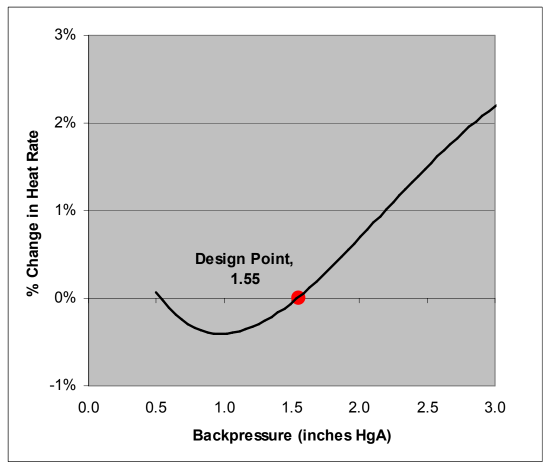

Figure G–9. Estimated Heat Rate Correction (Units 1 & 2)

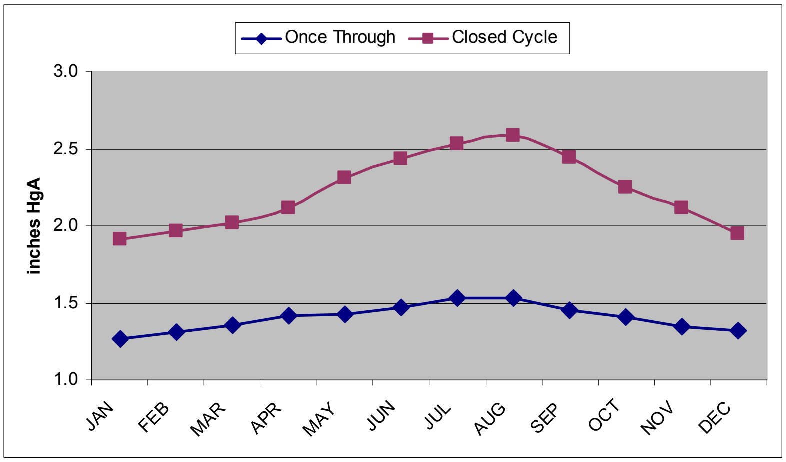

Figure G-10. Estimated Backpressures (Units 3 & 4)

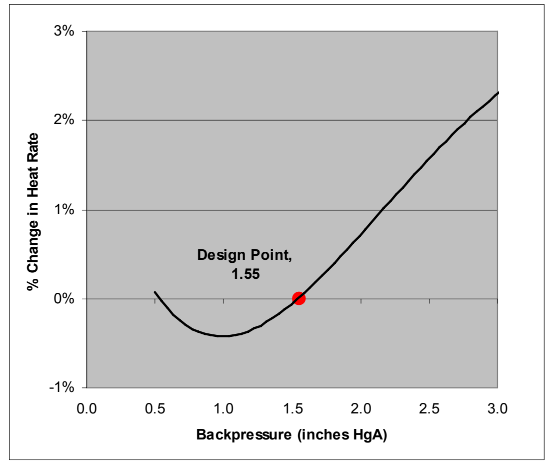

Figure G-11. Estimated Heat Rate Correction (Units 3 & 4)

4.0 RETROFIT COST ANALYSIS

The wet cooling system retrofit estimate for HBGS is based on incorporating conventional wet cooling towers as a replacement for the existing once-through system for each unit. Standard cost elements for this project include the following:

- Direct (cooling tower installation, civil/structural, mechanical, piping, electrical, and demolition)
- Indirect (smaller project costs not itemized)
- Contingency (allowance for unknown project variables)
- Revenue loss from shutdown (net loss in revenue during construction phase)
- Operations and maintenance (non–energy related cooling tower operations)
- Energy penalty (includes increased parasitic use from fans and pumps as well as decreased thermal efficiency)

The cost analysis does not include allowances for elements that are not quantified in this study, such as land acquisition, effluent treatment, or air emission reduction credits. The methodology used to develop cost estimates is discussed in Chapter 5.

4.1 COOLING TOWER INSTALLATION

In general, the cooling tower configuration selected for HBGS conforms to a typical design; no significant variations from a conventional arrangement were needed. Table G–14 summarizes the design-and-build cost estimate for each tower developed by vendors, inclusive of all labor and management required for their installation.

Table G–14. Wet Cooling Tower Design-and-Build Cost Estimate

	Units 1 & 2	Units 3 & 4	HBGS total
Number of cells	14	14	**28**
Cost/cell ($)	279,286	279,286	**279,286**
Total HBGS D&B cost ($)	**3,910,000**	**3,910,000**	**7,820,000**

4.2 OTHER DIRECT COSTS

A significant portion of wet cooling tower installation costs result from the various support structures, materials, equipment and labor necessary to prepare the cooling tower site and connect the towers to the condenser. At HBGS, these costs comprise approximately 90 percent of the initial capital cost. Line item costs are detailed in Appendix B.

Deviations from or additions to the general cost elements discussed in Chapter 5 are discussed below. Other direct costs (non–cooling tower) are summarized in Table G–15.

- *Civil, Structural, and Piping*
  The cooling towers' location with respect to the generating units represents the largest single increase in cost over an average configuration. More than 15,000 feet of large diameter pipe are required to service the cooling towers.
- *Mechanical and Electrical*
  Initial capital costs in this category reflect the new pumps (eight total) to circulate cooling water between the towers and condensers. No new pumps are required to provide makeup water from the Pacific Ocean. Electrical costs are based on the battery limit after the main feeder breakers.
- *Demolition*
  Demolition of one of the remaining empty fuel tanks is included. This study assumes the tank has been decommissioned and does not require hazardous material handling and disposal.

Table G–15. Summary of Other Direct Costs

	Equipment ($)	Bulk material ($)	Labor ($)	HBGS total ($)
Civil/structural/piping	6,200,000	27,700,000	15,900,000	**49,800,000**
Mechanical	14,600,000	0	400,000	**15,000,000**
Electrical	2,000,000	3,900,000	2,600,000	**8,500,000**
Demolition	0	0	400,000	**400,000**
Total HBGS other direct costs	**22,800,000**	**31,600,000**	**19,300,000**	**73,700,000**

4.3 INDIRECT AND CONTINGENCY

Indirect costs are calculated as 25 percent of all direct costs (civil/structural, mechanical, electrical, demolition, and cooling towers).

An additional allowance is included for condenser water box and tube sheet reinforcement to withstand the increased pressures associated with a recirculating system. Each condenser may require reinforcement of the tube sheet bracing with 6-inch x 1-inch steel, and water box reinforcement/replacement with 5/8-inch carbon steel. Based on the estimates outlined in Chapter 5, a conservative estimate of 5 percent of all direct costs is included to account for possible condenser modifications.

The contingency cost is calculated as 25 percent of the sum of all direct and indirect costs, including condenser reinforcement. At HBGS, potential costs in this category include relocating or demolishing small buildings and structures and potential interferences from underground structures.

Soils were not characterized for this analysis. Initial capital costs are summarized in Table G–16.

Table G–16. Summary of Initial Capital Costs

	Cost ($)
Cooling towers	7,800,000
Civil/structural/piping	49,800,000
Mechanical	15,000,000
Electrical	8,500,000
Demolition	400,000
Indirect cost	20,400,000
Condenser modification	4,100,000
Contingency	26,500,000
Total HBGS capital cost	**132,500,000**

4.4 SHUTDOWN

A portion of the work relating to installing wet cooling towers can be completed without significant disruption to the operations of HBGS. Units will be offline depending on the length of time it takes to integrate the new cooling system and conduct acceptance testing. For HBGS, a conservative estimate of 4 weeks per unit was developed. Based on 2006 generating output, however, no shutdown is forecast for either unit. Therefore, the cost analysis for HBGS does not include any loss of revenue associated with shutdown at HBGS.

This analysis did not consider shutdown with respect to the required availability of a particular generating unit, nor can it automatically be assumed that the generating profile for 2006 will be the same in each subsequent year. Net output data from 2006 may not reflect any contractual obligations that mandate a particular unit's availability during a given time period.

4.5 OPERATIONS AND MAINTENANCE

O&M costs for a wet cooling tower system at HBGS include routine maintenance activities; chemicals and treatment systems to control fouling and corrosion in the towers; management and labor; and an allowance for spare parts and replacement. Annual costs are calculated based on the combined tower flow rate using a base cost of $4.00/gpm in Year 1 and $5.80/gpm in Year 12, with an annual escalator of 2 percent (USEPA 2001). Year 12 costs increase based on the assumption that maintenance needs, particularly for spare parts and replacements, will be greater for years 12–20. Annual O&M costs, based on the design circulating water flow for the two cooling towers at HBGS (336,000 gpm), are presented in Table G–17. These costs reflect maximum operation.

Table G–17. Annual O&M Costs (Full Load)

	Year 1 cost ($)	Year 12 cost ($)
Management/labor	336,000	487,200
Service/parts	537,600	779,520
Fouling	470,400	682,080
Total HBGS O&M cost	**1,344,000**	**1,948,800**

4.6 ENERGY PENALTY

The energy penalty is divided into two components: increased parasitic use from the added electrical demand from tower fans and pumps; and the decrease in thermal efficiency from elevated turbine backpressures. Monetizing the energy penalty at HBGS requires some assumption as to how the facility will choose to alter its operations to compensate for these changes, if at all. One option would be to accept the reduced amount of revenue-generating electricity available for sale and absorb the economic loss ("production loss option"). A second option would be to increase the firing rate to the turbine (i.e., consume more fuel) and produce the same amount of revenue-generating electricity as had been obtained with the once-through cooling system ("increased fuel option"). The degree to which a facility is able, or prefers, to operate at a higher firing rate, however, produces the more likely scenario—some combination of the two.

Ultimately, the manner in which HBGS would alter operations to address efficiency changes is driven by considerations unknown to this study (e.g., corporate strategy, contractual obligations, operating protocols and turbine pressure tolerances). In all summary cost estimates, this study calculates the energy penalty's monetized value by assuming the facility will use the increased fuel option to compensate for reduced efficiency and generate the amount of electricity equivalent to the estimated shortfall. With this option, the energy penalty is equivalent to the financial cost of additional fuel and is nominally less costly than the production loss option. This option, however, may not reflect long-term costs such as increased maintenance or system degradation that may result from continued operation at a higher-than-designed turbine firing rate.

The energy penalty for HBGS is calculated by first estimating the increased parasitic demand from the cooling tower pumps and fans, expressed as a percentage of each unit's rated capacity. Likewise, the change in the unit's heat rate is also expressed as a capacity percentage.

4.6.1 INCREASED PARASITIC USE (FANS AND PUMPS)

Depending on ambient conditions or the operating load at a given time, HBGS may be able to take one or more cooling tower cells offline and still obtain the required level of cooling. This would also reduce the cumulative electrical demand from the fans. For the purposes of this study, however, operations are evaluated at the design conditions, i.e., full load; no allowance is made for seasonal changes. The increased electrical demand from cooling tower fan operation is summarized in Table G–18.

Table G–18. Cooling Tower Fan Parasitic Use

	Tower Complex 1	Tower Complex 2	HBGS total
Units served	Units 1&2	Units 3&4	--
Generating capacity (MW)	430	450	**880**
Number of fans (one per cell)	14	14	**28**
Motor power per fan (hp)	211	211	--
Total motor power (hp)	2,947	2,947	**5,895**
MW total	2.20	2.20	**4.40**
Fan parasitic use (% of capacity)	**0.51%**	**0.49%**	**0.50%**

Additional circulating water pump capacity for the wet cooling towers will also increase the parasitic electricity usage at HBGS. Makeup water will continue to be withdrawn from the Pacific Ocean with one of the existing circulating water pumps; the remaining pumps will be retired.

The net increase in pump-related parasitic usage is the difference between the new wet cooling tower configuration (new plus retained pumps) and the existing once-through configuration. For calculation purposes, this study assumes full-load operation to estimate the cost of increased parasitic use. Final estimates, therefore, allocate the retained pump's electrical demand to each tower based on the proportion of the facility's generating capacity it services. Operating fewer towers or tower cells will alter the allocation of the retained pump's electrical demand, but not the total demand.

Because one of the main design assumptions maintains the existing flow rate through each condenser, the new circulating pumps are single speed and are assumed to operate at their full rated capacity when in use. The increased electrical demand associated with cooling tower pump operation is summarized in Table G–19.

Table G–19. Cooling Tower Pump Parasitic Use

	Tower Complex 1	Tower Complex 2	HBGS total
Units served	Units 1&2	Units 3&4	--
Generating capacity (MW)	430	450	**880**
Existing pump configuration (hp)	1,600	1,600	**3,200**
New pump configuration (hp)	5,382	5,382	**10,764**
Difference (hp)	3,782	3,782	**7,564**
Difference (MW)	2.8	2.8	**5.6**
Net pump parasitic use (% of capacity)	**0.66%**	**0.63%**	**0.64%**

4.6.2 HEAT RATE CHANGE

Heat rate adjustments were calculated based on each month's ambient climate conditions and reflect the estimated difference between operations with once-through and wet cooling tower systems. As noted above, the energy penalty analysis assumes HBGS will increase its fuel consumption to compensate for lost efficiency and the increased parasitic load from fans and pumps. The higher turbine firing rate will increase the thermal load rejected to the condenser, which, in turn, results in a higher backpressure value and corresponding increase in the heat rate. No data are available describing the changes in turbine backpressures above the design thermal loads. For the purposes of monetizing the energy penalty only, this study conservatively assumed an additional increase in the heat rate of 0.5 percent at the higher firing rate; the actual effect at HBGS may be greater or less. Changes in the heat rate for each unit at HBGS are presented in Figure G–12 and Figure G–13.

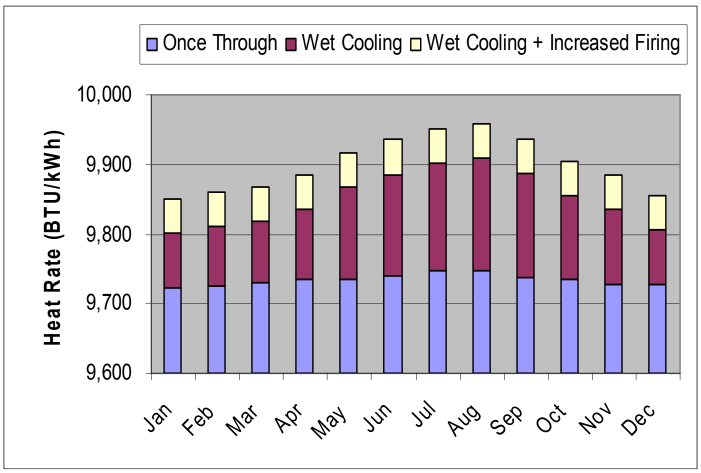

Figure G–12. Estimated Heat Rate Change (Units 1 & 2)

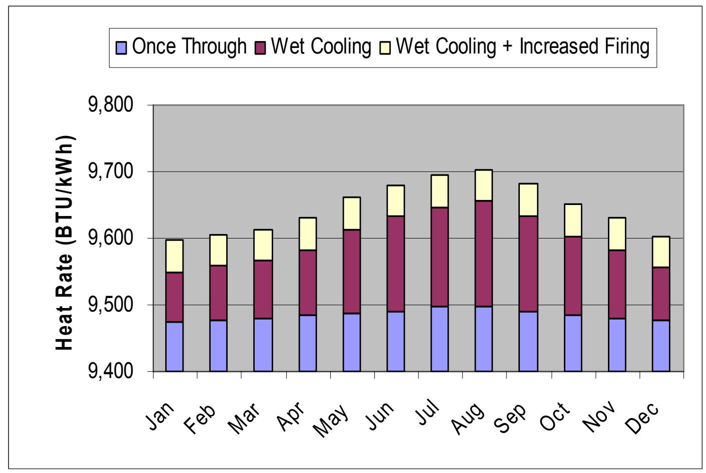

Figure G–13. Estimated Heat Rate Change (Units 3 & 4)

4.6.3 CUMULATIVE ESTIMATE

Using the increased fuel option, the energy penalty's cumulative value is obtained by first calculating the relative costs of generation ($/MWh) for the once-through system and the wet cooling system adjusted for a higher turbine firing rate. The cost of generation for HBGS is based on the relative heat rates developed in Section 4.6.2 and the average monthly wholesale natural gas cost ($/MMBTU) (ICE 2006a). The difference between these two values represents the monthly increased cost, per MWh, that results from converting to wet cooling towers. This value is then applied to the net MWh generated for the each month and summed to calculate the annual cost.

Based on 2006 output data, the Year 1 energy penalty for HBGS will be approximately $1.1 million. In contrast, the energy penalty's value calculated with the production loss option would be approximately $1.9 million. Together, these values represent the range of potential energy penalty costs for HBGS. Table G–20 and Table G–21 summarize the energy penalty estimates for each unit using the increased fuel option.

Table G–20. Units 1 & 2 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	9,723	58.34	9,850	59.10	0.76	60,424	46,020
February	5.50	9,726	53.49	9,859	54.22	0.73	49,005	35,881
March	4.75	9,729	46.21	9,867	46.87	0.65	51,096	33,451
April	4.75	9,735	46.24	9,884	46.95	0.71	39,652	28,118
May	4.75	9,736	46.25	9,916	47.10	0.86	44,134	37,802
June	5.00	9,741	48.70	9,935	49.68	0.97	81,503	79,283
July	6.50	9,748	63.36	9,951	64.68	1.32	120,493	158,954
August	6.50	9,747	63.35	9,959	64.73	1.38	82,262	113,462
September	4.75	9,738	46.26	9,936	47.20	0.94	79,832	75,199
October	5.00	9,734	48.67	9,905	49.53	0.86	28,155	24,082
November	6.00	9,729	58.37	9,884	59.30	0.93	26,014	24,203
December	6.50	9,727	63.22	9,856	64.06	0.84	36,018	30,245
							Units 1 & 2 total	**686,700**

Table G–21. Units 3 & 4 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	9,474	56.84	9,598	57.59	0.74	18,171	13,485
February	5.50	9,476	52.12	9,606	52.83	0.71	25,048	17,869
March	4.75	9,480	45.03	9,614	45.67	0.64	9,037	5,765
April	4.75	9,485	45.05	9,631	45.75	0.69	81,187	56,095
May	4.75	9,486	45.06	9,662	45.89	0.83	5,120	4,273
June	5.00	9,491	47.45	9,680	48.40	0.95	62,961	59,676
July	6.50	9,498	61.73	9,695	63.02	1.29	163,804	210,549
August	6.50	9,497	61.73	9,704	63.07	1.34	24,122	32,418
September	4.75	9,488	45.07	9,682	45.99	0.92	27,026	24,805
October	5.00	9,484	47.42	9,651	48.26	0.83	0	0
November	6.00	9,479	56.87	9,630	57.78	0.91	10,995	9,967
December	6.50	9,477	61.60	9,603	62.42	0.82	14,679	12,010
							Units 3 & 4 total	**446,912**

4.7 NET PRESENT COST

The Net Present Cost (NPC) of a wet cooling system retrofit at HBGS is the sum of all annual expenditures over the project's 20-year life span discounted according to the year in which the expense is incurred and the selected discount rate. The NPC represents the total change in revenue streams, in 2007 dollars, that HBGS can expect over 20 years as a direct result of converting to wet cooling towers. The following values were used to calculate the NPC at a 7 percent discount rate:

- *Capital and Start-up.* Includes all capital, indirect, contingency, and shutdown costs. All costs in this category are incurred in Year 0. (See Table G–16.)
- *Annual O&M.* Base cost values for Year 1 and Year 12 are adjusted for subsequent years using a 2 percent year-over-year escalator. Because HBGS has a relatively low capacity utilization factor, O&M costs for the NPC calculation were estimated at 50 percent of their maximum value. (See Table G–17.)
- *Annual Energy Penalty.* Insufficient information is available to this study to forecast future generating output at HBGS. In lieu of annual estimates, this study uses the net MWh output from 2006 as the calculation basis for Years 1 through 20. Wholesale prices include a year-over-year price escalator of 5.8 percent (based on the Producer Price Index). The energy penalty values are based on the increased fuel option discussed in Section 4.6. (See Table G–20 and Table G–21.)

Using these values, the NPC_{20} for HBGS is $160 million. Appendix C contains detailed annual calculations used to develop this cost.

4.8 ANNUAL COST

The annual cost incurred by HBGS for a wet cooling tower retrofit is the sum of annual amortized capital costs plus the annual average of O&M and energy penalty expenditures. Capital costs are amortized at a 7 percent discount rate over 20 years. O&M and energy penalty costs are calculated in the same manner as for the NPC_{20} (Section 4.7). Revenue losses from a construction-related shutdown, if any, are incurred in Year 0 only and not included in the annual cost summarized in Table G–22.

Table G–22. Annual Cost

Discount Rate (%)	Capital Cost ($)	Annual O&M ($)	Annual energy penalty ($)	Annual cost ($)
7.00	12,500,000	900,000	2,000,000	**15,400,000**

4.9 COST-TO-GROSS REVENUE COMPARISON

Limited financial data are available to conduct a detailed analysis of the economic impact that a wet cooling system retrofit will have on HBGS's annual revenues. The facility's gross annual revenue can be approximated using 2006 net generating data (CEC 2006) and average wholesale prices for electricity as recorded at the SP 15 trading hub (ICE 2006b). This estimate, therefore, does not reflect any changes that may result from different wholesale prices or contract agreements that may increase or decrease the gross revenue summarized below, nor does it account for annual fixed revenue requirements or other variable costs.

The estimate of gross annual revenue from electricity sales at HBGS is a straightforward calculation that multiplies the monthly wholesale cost of electricity by the amount generated for the particular month. The estimated gross revenue for HBGS is summarized in Table G–23. A comparison of annual costs to annual gross revenue is summarized in Table G–24.

Table G–23. Estimated Gross Revenue

	Wholesale price ($/MWh)	Net generation (MWh)		Estimated gross revenue ($)		
		Units 1 & 2	Units 3 & 4	Units 1 & 2	Units 3 & 4	HBGS total
January	66	60,424	18,171	3,987,984	1,199,286	**5,187,270**
February	61	49,005	25,048	2,989,305	1,527,928	**4,517,233**
March	51	51,096	9,037	2,605,896	460,887	**3,066,783**
April	51	39,652	81,187	2,022,252	4,140,537	**6,162,789**
May	51	44,134	5,120	2,250,834	261,120	**2,511,954**
June	55	81,503	62,961	4,482,665	3,462,855	**7,945,520**
July	91	120,493	163,804	10,964,863	14,906,164	**25,871,027**
August	73	82,262	24,122	6,005,126	1,760,906	**7,766,032**
September	53	79,832	27,026	4,231,096	1,432,378	**5,663,474**
October	57	28,155	0	1,604,835	0	**1,604,835**
November	66	26,014	10,995	1,716,924	725,670	**2,442,594**
December	67	36,018	14,679	2,413,206	983,493	**3,396,699**
HBGS total		**698,588**	**442,150**	**45,274,986**	**30,861,224**	**76,136,210**

Table G–24. Cost-Revenue Comparison

Estimated gross annual revenue ($)	Initial capital		O&M		Energy penalty		Total annual cost	
	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross
76,100,000	12,500,000	16.4	900,000	1.2	2,000,000	2.6	**15,400,000**	**20.2**

5.0 OTHER TECHNOLOGIES

Within the scope of this study, and using the OPC resolution's stated goal of reducing impingement and entrainment by 90–95 percent as a benchmark, the effectiveness of other technologies commonly used to address such impacts could not be conclusively determined for use at HBGS.

Among these technologies, however, and within the framework of this study, fine-mesh wedgewire screens exhibit the greatest potential for successful deployment. A final conclusion as to their applicability will have to be based on a more detailed site-specific investigation of the source water's physical characteristics. A more detailed analysis that also comprises a biological evaluation may determine the applicability of one or more of these technologies to HBGS. A brief summary of the applicability of these technologies follows.

5.1 MODIFIED RISTROPH SCREENS—FINE MESH

The principal concern with this technology is the successful return of viable organisms captured on the screens to the source water body. HBGS currently withdraws its cooling water through a submerged conduit extending approximately 1,500 feet offshore at a depth of 18 feet. It is unclear whether organisms could be returned to a near-shore location closer to the facility and remain viable.

5.2 BARRIER NETS

Barrier nets are unproven in an open ocean environment.

5.3 AQUATIC FILTRATION BARRIERS

Aquatic filtration barriers (AFBs) are unproven in an open ocean environment.

5.4 VARIABLE SPEED DRIVES

Variable speed drives (VSDs) were not considered for analysis at HBGS because the technology alone cannot be expected to achieve the desired level of reductions in impingement and entrainment, nor could it be combined with another technology to yield the desired reductions.

Pumps that have been retrofitted with VSDs can reduce overall flow intake volumes by 10–35 percent over the current once-through configuration (USEPA 2001). The actual reduction, however, will vary based on the cooling water demand at different times of the year. At peak demand, the pumps will essentially function as standard circulating water pumps and withdraw water at the maximum rated capacity, negating any potential benefit. Use of VSDs may be an economically desirable option when pumps are retrofitted or replaced for other reasons, but were not considered further for this study.

5.5 CYLINDRICAL FINE MESH WEDGEWIRE

Fine-mesh cylindrical wedgewire screens have not been deployed or evaluated at open coastal facilities for applications as large as required at HBGS (approximately 484 mgd). To function as intended, cylindrical wedgewire screens must be submerged in a water body with a consistent ambient current of 0.5 fps. Ideally, this current would be unidirectional so that screens may be oriented properly and any debris impinged on the screens will be carried downstream when the airburst cleaning system is activated.

Fine-mesh wedgewire screens for HBGS would be located offshore in the Pacific Ocean, west of the facility. Information regarding the subsurface currents in the near-shore environment close to HBGS is limited. Data suggest that these currents are multidirectional, depending on the tide and season, and fluctuate in terms of velocity, with prolonged periods below 0.5 fps (SCCOOS 2006).

To attain sufficient depth (approximately 20 feet) and an ambient current that might allow deployment, screens would need to be located 2,000 feet or more offshore. Discussions with vendors who design these systems indicated that distances more than 1,000 to 1,500 feet become problematic due to the inability of the airburst system to maintain adequate pressure for sufficient cleaning (Someah 2007). Together, these considerations preclude further evaluation of fine-mesh cylindrical wedgewire screens at HBGS.

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Appendix A. Once-Through and Closed-Cycle Thermal Performance

		Units 1 & 2			Units 3 & 4		
		Once through	Closed cycle	Net increase	Once through	Closed cycle	Net increase
JAN	Backpressure (in. HgA)	1.27	1.91	**0.64**	1.27	1.91	**0.64**
	Heat rate Δ (%)	*-0.28*	*0.52*	***0.80***	*-0.28*	*0.52*	***0.80***
FEB	Backpressure (in. HgA)	1.31	1.97	**0.66**	1.31	1.97	**0.66**
	Heat rate Δ (%)	*-0.25*	*0.61*	***0.86***	*-0.25*	*0.61*	***0.86***
MAR	Backpressure (in. HgA)	1.35	2.02	**0.66**	1.35	2.02	**0.66**
	Heat rate Δ (%)	*-0.21*	*0.70*	***0.91***	*-0.21*	*0.70*	***0.91***
APR	Backpressure (in. HgA)	1.41	2.12	**0.70**	1.41	2.12	**0.70**
	Heat rate Δ (%)	*-0.16*	*0.87*	***1.03***	*-0.16*	*0.87*	***1.03***
MAY	Backpressure (in. HgA)	1.43	2.31	**0.89**	1.43	2.31	**0.89**
	Heat rate Δ (%)	*-0.15*	*1.20*	***1.34***	*-0.15*	*1.20*	***1.34***
JUN	Backpressure (in. HgA)	1.47	2.43	**0.96**	1.47	2.43	**0.96**
	Heat rate Δ (%)	*-0.10*	*1.39*	***1.49***	*-0.10*	*1.39*	***1.49***
JUL	Backpressure (in. HgA)	1.54	2.53	**0.99**	1.54	2.53	**0.99**
	Heat rate Δ (%)	*-0.02*	*1.55*	***1.57***	*-0.02*	*1.55*	***1.57***
AUG	Backpressure (in. HgA)	1.53	2.58	**1.06**	1.53	2.58	**1.06**
	Heat rate Δ (%)	*-0.03*	*1.64*	***1.67***	*-0.03*	*1.64*	***1.67***
SEP	Backpressure (in. HgA)	1.45	2.44	**0.99**	1.45	2.44	**0.99**
	Heat rate Δ (%)	*-0.12*	*1.41*	***1.53***	*-0.12*	*1.41*	***1.53***
OCT	Backpressure (in. HgA)	1.41	2.25	**0.84**	1.41	2.25	**0.84**
	Heat rate Δ (%)	*-0.16*	*1.09*	***1.25***	*-0.16*	*1.09*	***1.25***
NOV	Backpressure (in. HgA)	1.34	2.12	**0.77**	1.34	2.12	**0.77**
	Heat rate Δ (%)	*-0.22*	*0.87*	***1.09***	*-0.22*	*0.87*	***1.09***
DEC	Backpressure (in. HgA)	1.32	1.95	**0.63**	1.32	1.95	**0.63**
	Heat rate Δ (%)	*-0.24*	*0.58*	***0.82***	*-0.24*	*0.58*	***0.82***

Note: Heat rate delta represents change from design value calculated according to estimated ambient conditions for each month.

Appendix B. Itemized Capital Costs

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
CIVIL / STRUCTURAL / PIPING	--	--	--	--	--	--	--	--	--	--
Allocation for other accessories (bends, water hammers…)	lot	1	--	--	500,000	500,000	4,000.00	85	340,000	**840,000**
Allocation for pipe racks (approx 1200 ft) and cable racks	t	120	--	--	2,500	300,000	17.00	105	214,200	**514,200**
Allocation for sheet piling and dewatering	lot	2	--	--	500,000	1,000,000	5,000.00	100	1,000,000	**2,000,000**
Allocation for testing pipes	lot	2	--	--	--	--	2,000.00	95	380,000	**380,000**
Allocation for Tie-Ins to existing condenser's piping	lot	1	--	--	250,000	250,000	2,000.00	85	170,000	**420,000**
Allocation for trust blocks	lot	2	--	--	25,000	50,000	250.00	95	47,500	**97,500**
Backfill for PCCP pipe (reusing excavated material)	m3	41,287	--	--	--	--	0.04	200	330,296	**330,296**
Bedding for PCCP pipe	m3	6,928	--	--	25	173,200	0.04	200	55,424	**228,624**
Bend for PCCP pipe 30" & 36" diam (allocation)	ea	30	--	--	5,000	150,000	25.00	95	71,250	**221,250**
Bend for PCCP pipe 72" diam (allocation)	ea	100	--	--	18,000	1,800,000	40.00	95	380,000	**2,180,000**
Building architectural (siding, roofing, doors, painting…etc)	ea	4	--	--	57,500	230,000	690.00	75	207,000	**437,000**
Butterfly valves 30" c/w allocation for actuator & air lines	ea	34	30,800	1,047,200	--	--	50.00	85	144,500	**1,191,700**
Butterfly valves 36" c/w allocation for actuator & air lines	ea	6	33,600	201,600	--	--	50.00	85	25,500	**227,100**
Butterfly valves 54" c/w allocation for actuator & air lines	ea	24	60,900	1,461,600	--	--	55.00	85	112,200	**1,573,800**
Butterfly valves 72" c/w allocation for actuator & air lines	ea	24	96,600	2,318,400	--	--	75.00	85	153,000	**2,471,400**
Check valves 30"	ea	6	44,000	264,000	--	--	16.00	85	8,160	**272,160**
Check valves 36"	ea	4	48,000	192,000	--	--	24.00	85	8,160	**200,160**
Check valves 54"	ea	8	87,000	696,000	--	--	26.00	85	17,680	**713,680**
Concrete basin walls (all in)	m3	627	--	--	225	141,075	8.00	75	376,200	**517,275**
Concrete elevated slabs (all in)	m3	433	--	--	250	108,250	10.00	75	324,750	**433,000**
Concrete for transformers and oil catch basin (allocation)	m3	200	--	--	250	50,000	10.00	75	150,000	**200,000**
Concrete slabs on grade (all in)	m3	3,403	--	--	200	680,600	4.00	75	1,020,900	**1,701,500**
Ductile iron cement pipe 12" diam. for fire water line	ft	3,000	--	--	100	300,000	0.60	95	171,000	**471,000**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Excavation and backfill for fire line, blowdown & make-up (using excavated material for backfill except for bedding)	m3	21,853	--	--	--	--	0.08	200	349,648	**349,648**
Excavation for PCCP pipe	m3	63,980	--	--	--	--	0.04	200	511,840	**511,840**
Fencing around transformers	m	50	--	--	30	1,500	1.00	75	3,750	**5,250**
Flange for PCCP joints 30"	ea	8	--	--	2,260	18,080	16.00	95	12,160	**30,240**
Flange for PCCP joints 36"	ea	6	--	--	2,765	16,590	18.00	95	10,260	**26,850**
Flange for PCCP joints 72"	ea	32	--	--	9,860	315,520	25.00	95	76,000	**391,520**
Foundations for pipe racks and cable racks	m3	280	--	--	250	70,000	8.00	75	168,000	**238,000**
FRP flange 30"	ea	100	--	--	1,679	167,915	50.00	85	425,000	**592,915**
FRP flange 36"	ea	20	--	--	2,500	50,000	70.00	85	119,000	**169,000**
FRP flange 54"	ea	80	--	--	5,835	466,794	80.00	85	544,000	**1,010,794**
FRP flange 72"	ea	16	--	--	20,888	334,203	200.00	85	272,000	**606,203**
FRP pipe 54" diam.	ft	200	--	--	426	85,140	0.80	85	13,600	**98,740**
FRP pipe 72" diam.	ft	2,400	--	--	851	2,043,360	1.20	85	244,800	**2,288,160**
Harness clamp 30" & 36"c/w internal testable joint	ea	310	--	--	2,000	620,000	16.00	95	471,200	**1,091,200**
Harness clamp 72" c/w internal testable joint	ea	800	--	--	2,440	1,952,000	22.00	95	1,672,000	**3,624,000**
Joint for FRP pipe 54" diam.	ea	6	--	--	1,324	7,946	85.00	85	43,350	**51,296**
Joint for FRP pipe 72" diam.	ea	66	--	--	3,122	206,039	200.00	85	1,122,000	**1,328,039**
PCCP pipe 30" dia. for blowdown	ft	3,000	--	--	125	375,000	0.70	95	199,500	**574,500**
PCCP pipe 36" dia. for make-up water line	ft	3,000	--	--	160	480,000	0.80	95	228,000	**708,000**
PCCP pipe 72" diam.	ft	15,600	--	--	890	13,884,000	2.00	95	2,964,000	**16,848,000**
Riser (FRP pipe 30" diam X 40 ft)	ea	28	--	--	15,350	429,794	150.00	85	357,000	**786,794**
Structural steel for building	t	190	--	--	2,500	475,000	20.00	105	399,000	**874,000**
CIVIL / STRUCTURAL / PIPING TOTAL	**--**	**--**	**--**	**6,180,800**	**--**	**27,732,007**	**--**	**--**	**15,913,828**	**49,826,635**
DEMOLITION	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**
Demolition of 1 tank approx 250 ft diameter	ea	1	--	--	--	--	3,500.00	100	350,000	**350,000**
DEMOLITION TOTAL	**--**	**--**	**--**	**0**	**--**	**0**	**--**	**--**	**350,000**	**350,000**
ELECTRICAL	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**
4.16 kv cabling feeding MCC's	m	3,000	--	--	75	225,000	0.40	85	102,000	**327,000**
4.16kV switchgear - 7 breakers	ea	1	325,000	325,000	--	--	230.00	85	19,550	**344,550**
480 volt cabling feeding MCC's	m	1,500	--	--	70	105,000	0.40	85	51,000	**156,000**
480V Switchgear - 1 breaker 3000A	ea	4	30,000	120,000	--	--	80.00	85	27,200	**147,200**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Allocation for automation and control	lot	1	--	--	1,300,000	1,300,000	13,000.00	85	1,105,000	**2,405,000**
Allocation for cable trays and duct banks	m	3,000	--	--	75	225,000	1.00	85	255,000	**480,000**
Allocation for lighting and lightning protection	lot	1	--	--	200,000	200,000	2,000.00	85	170,000	**370,000**
Dry Transformer 2MVA xxkV-480V	ea	4	100,000	400,000	--	--	100.00	85	34,000	**434,000**
Lighting & electrical services for pump house building	ea	4	--	--	20,000	80,000	250.00	85	85,000	**165,000**
Local feeder for 1200 HP motor 4160 V (up to MCC)	ea	8	--	--	42,000	336,000	150.00	85	102,000	**438,000**
Local feeder for 200 HP motor 460 V (up to MCC)	ea	28	--	--	15,000	420,000	140.00	85	333,200	**753,200**
Oil Transformer 10/13.3MVA xx-4.16kV	ea	4	190,000	760,000	--	--	150.00	85	51,000	**811,000**
Primary breaker(xxkV)	ea	8	45,000	360,000	--	--	60.00	85	40,800	**400,800**
Primary feed cabling (assumed 13.8 kv)	m	6,000	--	--	175	1,050,000	0.50	85	255,000	**1,305,000**
ELECTRICAL TOTAL	**--**	**--**	**--**	**1,965,000**	**--**	**3,941,000**	**--**	**--**	**2,630,750**	**8,536,750**
MECHANICAL	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**
Allocation for ventilation of buildings	ea	4	25,000	100,000	--	--	250.00	85	85,000	**185,000**
Cooling tower for unit 3	lot	1	3,910,000	3,910,000	--	--	--	--	--	**3,910,000**
Cooling tower for unit 1	lot	1	3,910,000	3,910,000	--	--	--	--	--	**3,910,000**
Cooling tower for unit 2	lot	1	3,910,000	3,910,000	--	--	--	--	--	**3,910,000**
Cooling tower for unit 4	lot	1	3,910,000	3,910,000	--	--	--	--	--	**3,910,000**
Overhead crane 30 ton in (in pump house)	ea	4	75,000	300,000	--	--	100.00	85	34,000	**334,000**
Pump 4160 V 1200 HP	ea	8	800,000	6,400,000	--	--	420.00	85	285,600	**6,685,600**
MECHANICAL TOTAL	**--**	**--**	**--**	**22,440,000**	**--**	**0**	**--**	**--**	**404,600**	**22,844,600**

Appendix C. Net Present Cost Calculation

Project year	Capital/start-up ($)	O & M ($)	Energy penalty ($)		Total ($)	Annual discount factor	Present value ($)
			Units 1 & 2	Units 3 & 4			
0	132,500,000	--	--	--	132,500,000	1	132,500,000
1	--	672,000	686,699	446,911	1,805,610	0.9346	1,687,523
2	--	685,440	726,734	472,965	1,885,139	0.8734	1,646,481
3	--	699,149	769,103	500,539	1,968,791	0.8163	1,607,124
4	--	713,132	813,941	529,721	2,056,794	0.7629	1,569,128
5	--	727,394	861,394	560,603	2,149,392	0.713	1,532,516
6	--	741,942	911,613	593,287	2,246,842	0.6663	1,497,071
7	--	756,781	964,760	627,875	2,349,417	0.6227	1,462,982
8	--	771,917	1,021,006	664,480	2,457,403	0.582	1,430,209
9	--	787,355	1,080,531	703,220	2,571,105	0.5439	1,398,424
10	--	803,102	1,143,526	744,217	2,690,845	0.5083	1,367,757
11	--	819,164	1,210,193	787,605	2,816,963	0.4751	1,338,339
12	--	993,888	1,280,747	833,522	3,108,158	0.444	1,380,022
13	--	1,013,766	1,355,415	882,117	3,251,298	0.415	1,349,289
14	--	1,034,041	1,434,436	933,544	3,402,021	0.3878	1,319,304
15	--	1,054,722	1,518,063	987,970	3,560,755	0.3624	1,290,418
16	--	1,075,816	1,606,566	1,045,569	3,727,951	0.3387	1,262,657
17	--	1,097,333	1,700,229	1,106,525	3,904,087	0.3166	1,236,034
18	--	1,119,279	1,799,353	1,171,036	4,089,667	0.2959	1,210,133
19	--	1,141,665	1,904,255	1,239,307	4,285,227	0.2765	1,184,865
20	--	1,164,498	2,015,273	1,311,559	4,491,330	0.2584	1,160,560
Total							**160,430,836**

H. MANDALAY GENERATING STATION

RELIANT ENERGY, INC—OXNARD, CA

Contents

Tables

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Appendices

1.0 GENERAL SUMMARY

Retrofitting the existing once-through cooling system at Mandalay Generating Station (MGS) with closed-cycle wet cooling towers is technically and logistically feasible based on this study's design criteria, and will reduce cooling water withdrawals from Channel Islands Harbor by approximately 95 percent. Impingement and entrainment impacts would be reduced by a similar proportion.

The preferred option selected for MGS includes 2 conventional wet cooling towers (without plume abatement), with individual cells arranged in an inline configuration to accommodate limited space at the site. Space limitations do not appear substantial enough to preclude plume-abated towers in the design if they were required to mitigate visual impacts. Initial capital costs for the towers would also increase by a factor of 2 or 3 and require a larger siting area.

Construction-related shutdowns are estimated to take approximately 4 weeks per unit (concurrent), although MGS is not expected to incur any financial loss as a result based on 2006 capacity utilization rates for all units.

The cooling tower configuration designed under the preferred option complies with all identified local use restrictions and includes necessary mitigation measures, where applicable.

1.1 COST

Initial capital and net present costs associated with installing and operating wet cooling towers at MGS are summarized in Table H–1. Annualized costs based on 20-year average values for the various cost elements are summarized in Table H–2.

Table H–1. Cumulative Cost Summary

Cost category	Cost ($)	Cost per MWh (rated capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Total capital and start-up [a]	55,400,000	14.71	177
NPC_{20} [b]	61,200,000	16.24	196

[a] Includes all costs associated with the cooling tower construction and installation and shutdown loss, if any.
[b] NPC_{20} includes all capital costs, operation and maintenance costs, and energy penalty costs over 20 years discounted at 7 percent.

Table H–2. Annual Cost Summary

Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Capital and start-up	5,200,000	1.38	16.65
Operations and maintenance	300,000	0.08	0.96
Energy penalty	300,000	0.08	0.96
Total MGS annual cost	**5,800,000**	**1.54**	**18.57**

1.2 ENVIRONMENTAL

Environmental changes associated with a cooling tower retrofit for MGS are summarized in Table H–3 and discussed further in Section 3.4.

Table H–3. Environmental Summary

		Unit 1	Unit 2
Water use	Design intake volume (gpm)	83,700	83,700
	Cooling tower makeup water (gpm)	4,600	4,600
	Reduction from capacity (%)	95	95
Energy efficiency [a]	Summer heat rate increase (%)	0.43	0.43
	Summer energy penalty (%)	1.34	1.34
	Annual heat rate increase (%)	0.73	0.73
	Annual energy penalty (%)	1.64	1.64
Direct air emissions [b]	PM_{10} emissions (tons/yr) (maximum capacity)	48	48
	PM_{10} emissions (tons/yr) (2006 capacity utilization)	3.79	4.19

[a] Reflects the comparative increase between once-through and wet cooling systems, but does not account for any operational changes to address the change in efficiency, such as increased fuel consumption (see Section 4.6).

[b] Reflects emissions from the cooling tower only; does not include any increase in stack emissions.

1.3 OTHER POTENTIAL FACTORS

Considerations outside this study's scope may limit the practicality or overall feasibility of a wet cooling tower retrofit at Mandalay.

MGS may face wastewater discharge permit conflicts upon converting to wet cooling towers. Recent permit compliance history indicates effluent exceedances have occurred for some metals, principally copper, as a result of elevated levels in the intake water. If cooling tower makeup water is obtained from the current source (Channel Islands Harbor), compliance may become more difficult as a result of a wet cooling tower's concentrating effects on certain pollutants, particularly metals. These conflicts may be mitigated or eliminated through the use of reclaimed water as the makeup source.

2.0 BACKGROUND

MGS is a natural gas–fired steam electric generating facility located in the city of Oxnard, Ventura County, owned and operated by Reliant Energy, Inc. MGS currently operates two conventional steam turbine units (Units 1 and 2) and one gas combustion turbine unit (Unit 3) with a combined generating capacity of 560 MW. Unit 3 does not require cooling water and is used infrequently. For the purposes of this study, only Units 1 and 2 are considered, with a combined generating capacity of 230 MW. The facility occupies approximately 128 acres of a 205-acre industrial site south of McGrath State Beach on the Pacific Ocean, approximately 3.5 miles northwest of Channel Islands Harbor. (See Table H–4 and Figure H–1.)

Table H–4. General Information

Unit	In-service year	Rated capacity (MW)	2006 capacity utilization [a]	Condenser cooling water flow (gpm)
Unit 1	1959	215	7.80%	83,700
Unit 2	1959	215	8.60%	83,700
MGS total		**430**	**8.2%**	**167,400**

[a] *Quarterly Fuel and Energy Report—2006* (CEC 2006).

Figure H–1. General Vicinity of Mandalay Generating Station

2.1 COOLING WATER SYSTEM

MGS operates one cooling water intake structure (CWIS) to provide condenser cooling water to Units 1 and 2 (Figure H–2). Once-through cooling water is combined with low volume wastes generated by MGS and discharged through a single shoreline outfall to the Pacific Ocean. Surface water withdrawals and discharges are regulated by National Pollutant Discharge Eliminations System (NPDES) Permit CA0001180 as implemented by Los Angeles Regional Water Quality Control Board (LARWQCB) Order 01-057.[1]

Figure H–2. Site View

Cooling water is obtained from Channel Islands Harbor via the Edison Canal, a 2.5 mile man-made canal specifically constructed to provide cooling water to the station.

The Edison Canal was originally connected to Port Hueneme, located approximately 4.5 miles southeast of MGS, but was disrupted by the construction of the harbor in 1965, which largely consisted of expanding the existing Edison Canal for a marina and a new outlet to the Pacific Ocean. As a result, it is difficult to determine what constitutes the boundary between the Edison Canal and Channel Islands Harbor. Based on the Phase II rule, it is not entirely clear whether the source water for MGS is the harbor or the Pacific Ocean. For the purposes of this study, the harbor is referenced as the source water and the CWIS defined as the portion of Edison Canal extending northward from the West Channel Islands Boulevard overpass up to and including the intake screens at the facility.

[1] LARWQCB Order #01-057 expired on May 10, 2006 but has been administratively extended pending adoption of a renewed order.

In addition to the Edison Canal, the CWIS comprises two angled intake bays, each approximately 12 feet wide. Each bay is fitted with a pair of vertical slide screens 11.5 feet wide by 21 feet high with ½-inch mesh panels and arranged parallel to each other (one in front of the other). Screens are alternately removed from the water and cleaned with a high pressure spray to remove any debris or fish that have become impinged on the screen face. Captured debris is collected in a dumpster for disposal in a landfill. MGS reports the approach velocity to the screens as 1.4 feet per second (fps), which translates to an approximate through-screen velocity of 2.8 fps.

Downstream of each screen is a circulating water pump rated at 44,000 gallons per minute (gpm), for a total facility capacity of 176,000 gpm, or 254 million gallons per day (mgd) (Reliant 2005). The majority of the cooling water is directed to the condensers, with a small portion used for bearing cooling water.

At maximum capacity, MGS maintains a total pumping capacity rated at 254 mgd, with a combined condenser flow rating of 241 mgd. On an annual basis, MGS withdraws substantially less than its design capacity due to its low generating capacity utilization (8.3 percent for 2006). When in operation and generating the maximum load, MGS can be expected to withdraw water from the Channel Islands Harbor at a rate approaching its maximum capacity.

2.2 SECTION 316(B) PERMIT COMPLIANCE

The CWIS currently in operation at MGS does not use technologies generally considered to be effective at reducing impingement mortality and/or entrainment. LARWQCB Order 01-057, adopted in 2001, states that "the design, construction and operation of the intake structures [at MGS] represents Best Available Technology (BAT) [*sic*] as required by Section 316(b) of the Clean Water Act" (LARWQCB, 2001. Finding 15). The order does not contain any numeric or narrative limitations regarding impingement or entrainment resulting from CWIS operation, but does require semi-annual monitoring of impingement at each intake structure (coinciding with scheduled heat treatments). Based on the record available for review, MGS has been compliant with this permit requirement.

The LARWQCB has notified MGS of its intent to revisit requirements under CWA Section 316(b), including a determination of BTA for minimization of adverse environmental impact, during the current permit re-issuance process. A final decision regarding any Section 316(b)-related requirements has not been made as of the publication of this study.

3.0 WET COOLING SYSTEM RETROFIT

3.1 OVERVIEW

This study evaluates saltwater cooling towers as a retrofit option at MGS, with the current source water (Channel Islands Harbor) continuing to provide makeup water to the facility. Converting the existing once-through cooling system to wet cooling towers will reduce the facility's current intake capacity by approximately 95 percent; rates of impingement and entrainment will decline by a similar proportion. Use of reclaimed water was considered for MGS but not analyzed in detail because the available volume cannot serve as a replacement for once-through cooling water. The proximity of available sources, however, may make reclaimed water an attractive alternative as makeup water for a wet cooling tower system when considering additional benefits its use may provide, such as avoidance of conflicts with effluent limitations or air emission standards.

The wet cooling towers' configuration—their size, arrangement, and location—was based on best professional judgment (BPJ) using the criteria outlined in Chapter 5 and designed to meet the performance benchmarks in the most cost-effective manner. Information not available to this study that offers a more complete facility characterization may lead to different conclusions regarding the cooling towers' physical configuration.

This study developed a conceptual design of wet cooling towers sufficient to meet each active generating unit's cooling demand at its rated output during peak climate conditions. Cost estimates are based on vendor quotes developed using the available information and the various design constraints identified at MGS.

The overall practicality of retrofitting both units at MGS will require an evaluation of factors outside the scope of this study, such as each unit's age and efficiency and its role in the overall reliability of electricity production and transmission in California, particularly the Los Angeles Region.

3.2 DESIGN BASIS

3.2.1 CONDENSER SPECIFICATIONS

For this study, the wet cooling tower conceptual design selected for MGS is based on the assumption that the condenser flow rate and thermal load to each will remain unchanged from the current system. Although no provision is included to re-optimize the condenser performance for service with a cooling tower, some modifications to the condenser (tube sheet and water box reinforcement) may be necessary to handle the increased water pressures that will result from the increased total pump head required to raise water to the cooling tower riser elevation.[2] The practicality and difficulty of these modifications are dependent each unit's age and configuration but are assumed to be feasible at MGS. Condenser water boxes for both units are located at grade level and appear to be readily accessible. Additional costs for condenser modifications are included in the discussion of capital expenditures (Section 4.0).

Information provided by MGS was largely used as the basis for the cooling tower design. In some cases, the data were incomplete or conflicted with values obtained from other sources. Where possible, questionable values were verified or corrected using other known information about the condenser.

Parameters used in the development of the cooling tower design are summarized in Table H–5.

[2] In this context, re-optimization refers to a comprehensive condenser overhaul that reduces thermal efficiency losses associated with a wet cooling tower's higher circulating water temperatures. Modifications discussed in this study are generally limited to reinforcement measures that enable the condenser to withstand increased water pressures.

Table H–5. Condenser Design Specifications

	Unit 1	Unit 2
Thermal load (MMBTU/hr)	920.7	920.7
Surface area (ft^2)	110,000	110,000
Condenser flow rate (gpm)	83,700	83,700
Tube material	Aluminum brass	Aluminum brass
Heat transfer coefficient (BTU/hr•ft^2•°F)	560	560
Cleanliness factor	0.85	0.85
Inlet temperature (°F)	63	63
Temperature rise (°F)	22.01	22.01
Steam condensate temperature (°F)	91.7	91.7
Turbine exhaust pressure (in. HgA)	1.5	1.5

3.2.2 AMBIENT ENVIRONMENTAL CONDITIONS

MGS is located in Ventura County adjacent to Mandalay and the Pacific Ocean approximately 3.5 miles northwest of Channel Islands Harbor. Cooling water is withdrawn at the surface via the Edison Canal from the harbor, which opens to the Pacific Ocean. Inlet water temperatures are expected to be comparable to temperatures within the harbor. Data provided by MGS detailing monthly inlet temperatures contained gaps for some months when units were not operational. Surface water temperatures used in this analysis were supplemented with monthly average coastal water temperatures as reported in the NOAA *Coastal Water Temperature Guide for Ventura and Port Hueneme, CA* (NOAA 2007). A comparison between MGS and NOAA data indicates the inlet temperatures at MGS are typically a few degrees higher. Data obtained from NOAA sources have been adjusted accordingly.

The wet bulb temperature used in the development of the overall cooling tower design was obtained from American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) publications. Data for coastal Ventura County indicate a 1 percent ambient wet bulb temperature of 66° F (ASHRAE 2006). An approach temperature of 12° F was selected based on the site configuration and vendor input. At the design wet bulb and approach temperatures, the cooling towers will yield “cold” water at a temperature of 78° F.

Monthly maximum wet bulb temperatures used in the development of energy penalty estimates in Section 4.6 were calculated using data obtained from California Irrigation Management Information System (CIMIS) Monitoring Station 156 in Oxnard (CIMIS 2006). Climate data used in this analysis are summarized in Table H–6.

Table H–6. Surface Water and Ambient Wet Bulb Temperatures

	Surface (°F)	Ambient wet bulb (°F)
January	57.0	57.9
February	59.3	58.3
March	62.6	59.7
April	65.1	60.7
May	68.4	62.5
June	71.2	65.3
July	74.4	66.1
August	74.0	66.3
September	71.4	64.7
October	66.2	62.4
November	62.5	61.3
December	56.9	58.9

3.2.3 LOCAL USE RESTRICTIONS

3.2.3.1 NOISE

Industrial development in the vicinity of MGS is covered by the City of Oxnard General Plan and the City of Oxnard Land Use Plan (LUP). General Plan Section 10 (Noise Element) outlines the broad policy related to noise impacts within the city's different development zones. The plan outlines narrative criteria to be used as a guide for future development, but does not identify numeric noise limits for new construction (Oxnard 2006).

Land use within the general vicinity of MGS is primarily agricultural, although recent residential developments have encroached upon the area. Noise associated with the cooling towers is not expected to have any discernible impact upon these areas. The proximity to state beaches, however, may conflict with recreational standards set forth in the Ventura County Local Coastal Plan, but again, no numeric limits are specified.

In lieu of specific noise criteria, this study used an ambient noise limit of 65 dBA at a distance of 700 feet in selecting the design elements of the wet tower installation. Accordingly, the final design selected for MGS does not require any measures that specifically address noise, such as low-noise fans or barrier walls.

3.2.3.2 BUILDING HEIGHT

MGS is located within the coastal energy facilities subzone (EC) of the City of Oxnard LUP, which encourages the expansion of energy-related activities within the existing site consistent with other plan provisions. The LUP does not establish specific criteria for building height and instead relies on conditional use permitting that evaluates each project independently. Given the height of existing structures at MGS, this study selected a height restriction of 50 feet above grade level. The height of the wet cooling towers designed for MGS, from grade level to the top of the fan deck, is 44 feet.

3.2.3.3 PLUME ABATEMENT

Local zoning ordinances do not contain any specific criteria for addressing any impact associated with a wet cooling tower plume. Using the selection criteria for this study, plume abatement measures were not considered for MGS; all towers are a conventional design. The plume from wet cooling towers at MGS is not expected to adversely impact nearby infrastructure.

Community standards for assessing the visual impact associated with a cooling tower plume cannot be determined within the scope of this study. Agricultural uses predominate in the general vicinity of MGS, but residential development continues to encroach upon the facility. The proximity of MGS to coastal recreational areas (McGrath State Beach) and the potential visual impact on those resources may require plume abatement measures. CEC siting guidelines and Coastal Act provisions evaluate the total size and persistence of a visual plume with respect to aesthetic standards for coastal resources; significant visual changes resulting from a persistent plume would likely be subject to additional controls.

Plume abatement towers for MGS, if necessary, would be a feasible alternative given the relatively small size of the generating units and available land on which to locate them. The principal difference would be an escalation of the total cost (approximately 2 to 3 times the capital cost of conventional towers). The additional height required for plume-abated towers (approximately 15-20 feet) may conflict with height restrictions under local zoning ordinances, but this cannot be precisely determined.

3.2.3.4 DRIFT AND PARTICULATE EMISSIONS

Drift elimination measures that are considered best available control technology (BACT) are required for all cooling towers evaluated in this study, regardless of their location. State-of-the-art drift eliminators are included for each cooling tower cell at MGS, with an accepted efficiency of 0.0005 percent. Because cooling tower PM_{10} emissions are a function of the drift rate, drift eliminators are also considered BACT for PM_{10} emissions from wet cooling towers. This efficiency can be verified by a proper in situ test, which accounts for site-specific climate, water, and operating conditions. Testing based on the Cooling Tower Institute's Isokinetic Drift Test Code is required at initial start-up on only one representative cell of each tower for an approximate cost of $60,000 per test, or approximately $120,000 for both cooling towers at MGS (CTI 1994). This cost is not itemized in the final analysis and is instead included as part of the indirect cost estimate (Section 4.3).

3.2.3.5 FACILITY CONFIGURATION AND AREA CONSTRAINTS

The existing site's configuration and relative locations of the two generating units does not present any obvious challenges to identifying a location for wet cooling towers at the facility. As shown in Figure H–3, sufficient space exists in the facility's northern section. This area (Area 1) is currently unoccupied and lies approximately 700 feet south of McGrath Lake. The total size of this parcel, approximately 150,000 square feet, is sufficient to accommodate the two required cooling towers.

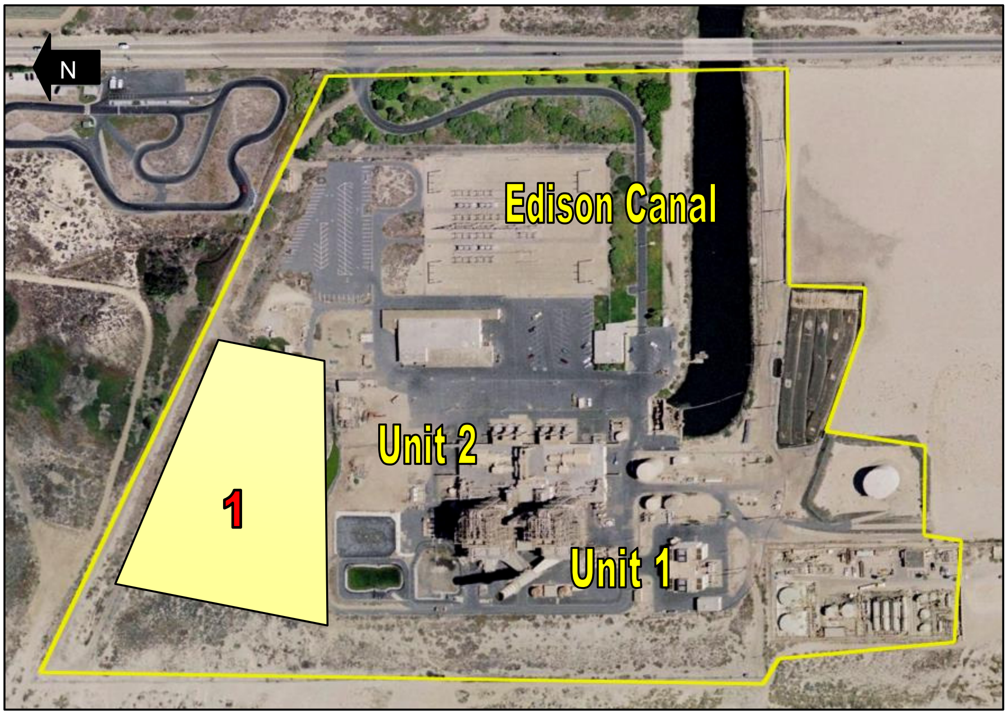

Figure H–3. Cooling Tower Siting Locations

3.3 CONCEPTUAL DESIGN

Based on the design constraints discussed above, two wet cooling towers were selected to replace the current once-through cooling system that serves Units 1 and 2 at MGS. Each unit will be served by an independently-functioning tower with separate pump houses and pumps. Both towers at MGS consist of conventional cells arranged in a multi-cell, inline configuration.

3.3.1 SIZE

Each tower is constructed over a concrete collection basin 4 feet deep. The basin is larger than the tower structure's footprint, extending an additional 2 feet in each direction. The concrete used for construction is suitable for saltwater applications. The principal tower material is fiberglass reinforced plastic (FRP), with stainless steel fittings. These materials are more resistant to the higher corrosive effects of saltwater.

The size of each tower is primarily based on the thermal load rejected to the tower by the surface condenser and a 12° F approach to the ambient wet bulb temperature. The flow rate through each condenser remains unchanged.

General characteristics of the wet cooling towers selected for MGS are summarized in Table H–7.

Table H-7. Wet Cooling Tower Design

	Tower 1 (Unit 1)	Tower 2 (Unit 2)
Thermal load (MMBTU/hr)	920.7	920.7
Circulating flow (gpm)	83,700	83,700
Number of cells	7	7
Tower type	Mechanical draft	Mechanical draft
Flow orientation	Counterflow	Counterflow
Fill type	Modular splash	Modular splash
Arrangement	Inline	Inline
Primary tower material	FRP	FRP
Tower dimensions (l x w x h) (ft)	336 x 54 x 44	336 x 54 x 44
Tower footprint with basin (l x w) (ft)	348 x 66	348 x 66

3.3.2 LOCATION

The initial site selection for each tower was based on the desire to locate each tower as close as possible to its respective generating unit to minimize the supply and return pipe distances and any increases in pump head and brake horsepower. Tower 1, serving Unit 1, is located at an approximate distance of 550 feet. Tower 2, serving Unit 2, is located at approximate distance of 800 feet. (Figure H–4).

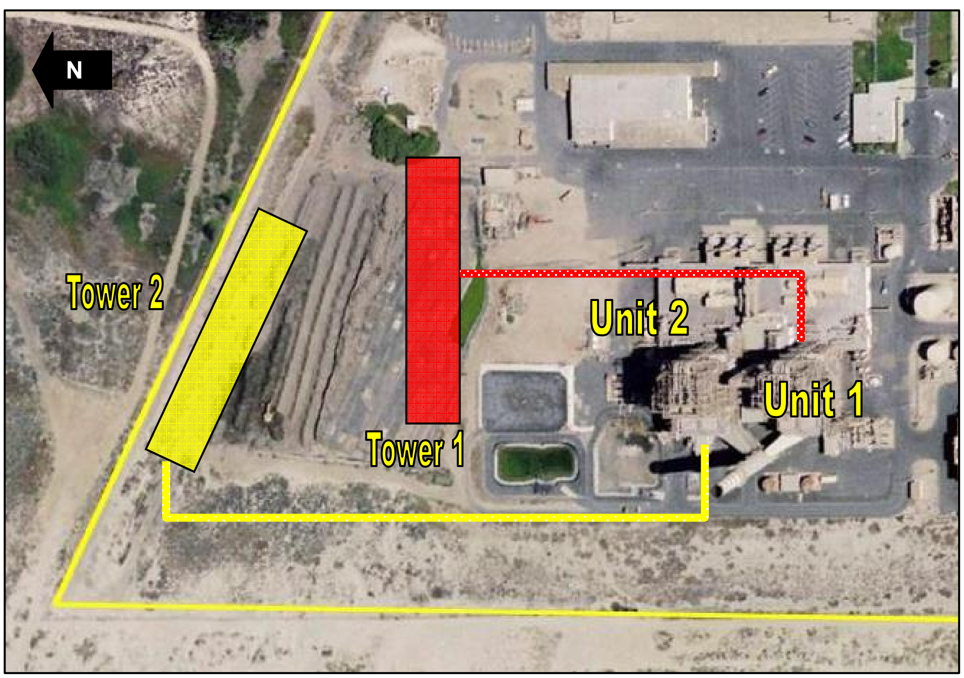

Figure H-4. Cooling Tower Locations

3.3.3 PIPING

The main supply and return pipelines to and from both towers will be located underground and made of prestressed concrete cylinder pipe (PCCP) suitable for saltwater applications. These pipes are sized at 72 inches in diameter. Pipes connecting the condensers to the supply and return lines are made of FRP and placed above ground on pipe racks. Above-ground placement avoids the potential disruption that may be caused by excavation in and around the power block. The condensers at MGS are located at grade level, enabling a relatively straightforward connection.

All riser piping (extending from the foot of the tower to the level of water distribution) is constructed of FRP.

Potential interference with underground obstacles and infrastructure is a concern, particularly at existing sites that are several decades old and have been substantially modified or rebuilt in the interim. Avoidance of these obstacles is considered to the degree practical in this study. Associated costs are included in the contingency estimate and are generally higher than similar estimates for new facilities (Section 4.3).

Appendix B details the total quantity of each pipe size and type for MGS.

3.3.4 FANS AND PUMPS

Each tower cell uses an independent single-speed fan. The fan size and motor power are the same for each cell in each tower.

This analysis includes new pumps to circulate water between the condensers and cooling towers. Pumps are sized according to the flow rate for each tower, the relative distance between the towers and condensers, and the total head required to deliver water to the top of each cooling tower riser. A separate, multilevel pump house is constructed for each tower and sized to accommodate the motor control centers (MCCs) and appropriate electrical switchgear. The electrical installation includes all necessary transformers, cabling, cable trays, lighting, and lightning protection. A 50-ton overhead crane is also included to allow for pump servicing.

Fan and pump characteristics associated with wet cooling towers at MGS are summarized in Table H–8. The net electrical demand of fans and new pumps is discussed further as part of the energy penalty analysis in Section Table H–8.

Table H-8. Cooling Tower Fans and Pumps

		Tower 1 (Unit 1)	Tower 2 (Unit 2)
Fans	Number	7	7
	Type	Single speed	Single speed
	Efficiency	0.95	0.95
	Motor power (hp)	211	211
Pumps	Number	2	2
	Type	50% recirculating Mixed flow Suspended bowl Vertical	50% recirculating Mixed flow Suspended bowl Vertical
	Efficiency	0.88	0.88
	Motor power (hp)	1,023	1,023

3.4 ENVIRONMENTAL EFFECTS

Converting the existing once-through cooling system at MGS to wet cooling towers will significantly reduce the intake of seawater from Channel Islands Harbor and will presumably reduce impingement and entrainment by a similar proportion. Because closed-cycle systems will almost always result in condenser cooling water temperatures higher than those found in a comparable once-through system, wet towers will increase the operating heat rates at both of MGS's steam units, thereby decreasing the facility's overall efficiency. Additional power will also be consumed by the tower fans and circulating pumps.

Depending on how MGS chooses to address this change in efficiency, total stack emissions may increase for pollutants such as $PM_{10,}$ $SO_{x,}$ and NO_x, and may require additional control measures (e.g., electrostatic precipitation, flue gas desulfurization, and selective catalytic reduction) or the purchase of emission credits to meet air quality regulations. The availability of emission reduction credits (ERCs) and their associated cost was not evaluated as part of this study. Both factors, however, may limit the air emission compliance options available to MGS.

No control measures are currently available for CO_2 emissions, which will increase, on a per-kWh basis, by the same proportion as any change in the heat rate. The towers themselves will constitute an additional source of PM_{10} emissions, the annual mass of which will largely depend on the capacity utilization rate for the generating units served by each tower.

If MGS retains its NPDES permit to discharge wastewater to the Pacific Ocean with a wet cooling tower system, it may have to address revised effluent limitations resulting from the substantial change in the discharge quantity and characteristics. Thermal impacts from the current once-through system, if any, will be minimized with a wet cooling system.

3.4.1 AIR EMISSIONS

MGS is located in the South Central Coast air basin. Air emissions are permitted by the Ventura County Air Pollution Control District (VCAPCD) (Facility ID 13).

Drift volumes are expected to be within the range of 0.5 gallons for every 100,000 gallons of circulating water in the towers. At MGS, this corresponds to a rate of approximately 0.84 gpm based on the maximum combined flow both two towers. Agricultural operations lie within 0.25 mile to the north and 0.75 mile to the east. Given the direction of prevailing winds (from the west) some drift may carry to these areas, but the impact is not likely to be significant.

Total PM_{10} emissions from the MGS cooling towers are a function of the number of hours in operation, the overall water quality in the tower, and the evaporation rate of drift droplets prior to deposition on the ground. Makeup water at MGS will be obtained from the same source currently used for once-through cooling water (Channel Islands Harbor). This water is drawn through the harbor from the Pacific Ocean and is the same as marine water with respect to the total dissolved solids (TDS) concentration. At 1.5 cycles of concentration and assuming an initial TDS value of 35 parts per thousand (ppt), the water within the cooling towers will reach a maximum TDS level of roughly 53 ppt. Any drift droplets exiting the tower will have the same TDS concentration.

The cumulative mass emission of PM_{10} from MGS will increase as a result of the direct emissions from the cooling towers themselves. Stack emissions of PM_{10}, as well as SO_x, NO_x, and other pollutants, will increase due to the drop in fuel efficiency, although the cumulative increase will depend on actual operations and emission control technologies currently in use. Maximum drift and PM_{10} emissions from the cooling towers are summarized in Table H–9.[3]

Data summarizing the total facility emissions for these pollutants in 2005 are presented in Table H–10 (CARB 2005). In 2005, MGS operated at an annual capacity utilization rate of 7.1 percent. Using this rate, the additional PM_{10} emissions from the cooling towers would increase the facility total by approximately 7 tons/year, or 150 percent.[4]

[3] This is a conservative estimate that assumes all dissolved solids present in drift droplets will be converted to PM_{10}. Studies suggest this may overestimate actual emission profiles for saltwater cooling towers (Chapter 4).

[4] 2006 emission data are not currently available from the Air Resources Board website. For consistency, the comparative increase in PM10 emissions estimated here is based on the 2005 MGS capacity utilization rate instead of the 2006 rate presented in Table H-4. All other calculations in this chapter use the 2006 value.

Table H–9. Full Load Drift and Particulate Estimates

	PM_{10} (lbs/hr)	PM_{10} (tons/year)	Drift (gpm)	Drift (lbs/hr)
Tower 1	11	48	0.42	209
Tower 2	11	48	0.42	209
Total MGS PM_{10} and drift emissions	**22**	**96**	**0.84**	**418**

Table H–10. 2005 Emissions of SO_x, NO_x, PM_{10}

Pollutant	Tons/year
NO_x	9.1
SO_x	1.0
PM_{10}	4.6

3.4.2 MAKEUP WATER

The volume of makeup water required by both cooling towers at MGS is the sum of evaporative loss and the blowdown volume required to maintain the circulating water in each tower at the design TDS concentration. Drift expelled from the towers represents an insignificant volume by comparison and is accounted for by rounding up evaporative loss estimates. Makeup water volumes are based on design conditions, and may fluctuate seasonally depending on climate conditions and facility operations. Wet cooling towers will reduce once-through cooling water withdrawals from Channel Islands Harbor by approximately 95 over the current design intake capacity.

Table H–11. Makeup Water Demand

	Tower circulating flow (gpm)	Evaporation (gpm)	Blowdown (gpm)	Total makeup water (gpm)
Tower 1	83,700	1,600	3,000	**4,600**
Tower 2	83,700	1,600	3,000	**4,600**
Total MGS makeup water demand	**167,400**	**3,200**	**6,000**	**9,200**

One circulating water pump, rated at 44,000 gpm, which is currently used to provide once-through cooling water to the facility, will be retained in a wet cooling system to provide makeup water to each cooling tower. The retained pump's capacity exceeds the makeup demand by approximately 34,000 gpm. Any excess capacity will be routed through a bypass conduit and returned to the wet well at a point located behind the intake screens. Recirculating the excess capacity in this manner reduces additional cost that would be incurred if new pumps were required while maintaining the desired flow reduction. The intake of new water, measured at the intake screens, will be equal to the cooling towers' makeup water demand. Figure H–5 presents a schematic of this configuration.

The existing once-through cooling system at MGS does not treat water withdrawn from Channels Islands Harbor, with the exception of screening for debris and larger organisms and periodic chlorination to control biofouling in the condenser tubes. Heat treatments are also periodically used to control mussel growth on pipes and condenser tubes by raising the circulating water temperature to 125º F. Conversion to a wet cooling tower system will not interfere with chlorination or heat treatment operations.

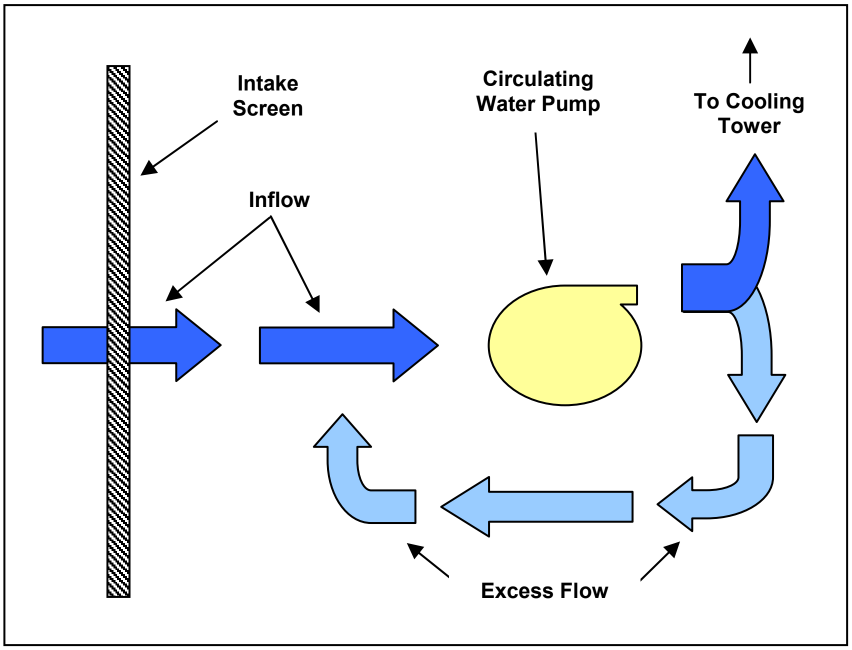

Figure H–5. Schematic of Intake Pump Configuration

Makeup water will continue to be withdrawn from the Channels Islands Harbor.

The wet cooling tower system proposed for MGS includes water treatment for standard operational measures, i.e., corrosion inhibitors, biocides, and anti-scaling agents. An allowance for these additional chemical treatments is included in annual O&M costs. It is assumed that the current once-through cooling water quality will be acceptable for use in a seawater cooling tower (with continued screening and chlorination) and will not require any pretreatment to enable its use.

3.4.3 NPDES PERMIT COMPLIANCE

At maximum operation, wet cooling towers at MGS will result in an effluent discharge of 8.6 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, regeneration wastes, and cleaning wastes. These low volume wastes may add an additional 0.25 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, MGS will be required to modify its existing individual wastewater discharge (NPDES) permit.

Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0001180 as implemented by LAWRQCB Order 01-057. All wastewaters are discharged to the Pacific Ocean via a rock-lined canal at the shoreline. The existing Order contains effluent limitations based on the 1997 Ocean Plan and the 1972 Thermal Plan.

MGS will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities (40 CFR 423.13(d)(1)). These ELGs set numeric limitations for chromium and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity). Because ELGs are technology-based limitations, mixing zones or dilution factors are not applicable when determining compliance; limits must be met at the point of discharge from the cooling tower prior to commingling with any other waste stream. ELGs for cooling tower blowdown target priority pollutants that are contributed by maintenance chemicals and do not apply when limits may be exceeded as a result of background concentrations or other sources. Further discussion can be found in Chapter 4, Section 3.6.

Conversion to wet cooling towers will alter the volume and composition of a facility's wastewater discharge because wet towers concentrate certain pollutants in the effluent waste stream. The cooling towers designed for MGS operate at 1.5 cycles of concentration, i.e., the blowdown discharge will contain a dissolved solids concentration 50 percent higher than the makeup water.

Changes to discharge composition may affect compliance with water quality objectives included in the Ocean Plan. If compliance with these objectives becomes problematic, alternative treatment or discharge methods may be necessary. Compliance may be achieved by altering the discharge configuration in such a way as to increase dilution (e.g., diffuser ports), or by seeking a mixing zone and dilution credits as permissible under the Ocean Plan. Alternately, some low volume waste streams (e.g., boiler blowdown, laboratory drains) may be diverted, with necessary permits, for treatment at a POTW.

MGS has had an ongoing issue due to elevated levels of copper present in the intake water withdrawn from the Edison Canal. Reliant Energy, Inc has argued that high levels of copper within Channel Islands Harbor and the Edison Canal are a result of other activities in the area and that MGS does not contribute copper, at any significant level, to the final discharge. The SWRCB agreed with the latter point, but rejected the appeal for permit relief, citing the Ocean Plan's definition of wastes as the "total discharge, of whatever origin" from the facility (SWRCB 2005). The SWRCB did note that MGS could modify its existing discharge structure to increase the level of dilution and thereby increase the monthly effluent limitations.

In addition to copper, data submitted by MGS in support of its NPDES renewal application demonstrates a reasonable potential to exceed effluent limitations for cadmium, chromium, and zinc (Reliant 2004). These assessments reflect the existing once-through cooling system and are primarily driven by the elevated concentrations of these pollutants detected in the intake water at MGS.

If more pollutant-specific treatment methods, such as filtration or precipitation technologies, become necessary to meet WQBELs, the initial capital cost may range from $2 to $5.50 per 1,000 gallons of treatment capacity, with annual costs of approximately $0.5 per gallon of capacity, depending on the method of treatment (FRTR 2002). Hazardous material disposal fees and permits would further increase costs.

This evaluation did not include alternative discharge or effluent treatment measures in the conceptual design because the variables used to determine final WQBELs, which would be used to determine the type and scope of the desired compliance method, cannot be quantified here. Likewise, the final cost evaluation (Section 4.0) does not include any allowance for these possibilities.

Use of reclaimed water as the cooling tower makeup source has the potential to reduce or eliminate conflicts with effluent limitations.

Thermal discharge standards are based on narrative criteria established for coastal discharges under the Thermal Plan, which requires that existing discharges of elevated-temperature wastes comply with effluent limitations necessary to assure the protection of designated beneficial uses. The LARWQCB has implemented this provision by establishing a maximum discharge temperature of 106º F during normal operations in Order 01-057 (LARWQCB 2001). Information available for review indicates MGS has consistently been able to comply with this requirement. Because cooling tower blowdown will be taken from the "cold" side of the tower, conversion to a wet cooling system will significantly reduce the discharge temperature (to less than 80º F) and the size of any related thermal plume in the receiving water.

3.4.4 RECLAIMED WATER

Reclaimed or alternative water sources used in conjunction with wet cooling towers could eliminate all surface water withdrawals at MGS. Doing so would completely eliminate impingement and entrainment concerns, and might enable the facility to avoid possible effluent quality and permit compliance issues, depending on the quality of reclaimed water available for use. In addition, wet cooling towers using reclaimed water would be expected to have lower PM_{10} emissions due to the lower TDS levels. The California State Water Resources Control Board (SWRCB), in 1975, issued a policy statement requiring the consideration of alternative cooling methods in new power plants, including reclaimed water, over the use of freshwater (SWRCB 1975). There is no similar policy regarding marine waters, but the clear preference of state agencies is to encourage alternative cooling methods, including reclaimed water, wherever possible.

The present volume of available reclaimed water within a 15-mile radius of MGS (50 mgd) does not meet the current once-through cooling demand; thus, reclaimed water is only applicable as a source of makeup water for a wet cooling tower system. This study did not pursue a detailed investigation of reclaimed water's use because the conversion of MGS's once-through cooling system to saltwater cooling towers meets the performance benchmarks for impingement and entrainment impact reductions discussed in the 2006 California Ocean Protection Council (OPC) Resolution on Once-Through Cooling Water (see Chapter 1).

To be acceptable for use as makeup water in cooling towers, reclaimed water must meet tertiary treatment and disinfection standards under California Code of Regulations (CCR) Title 22. If the reclaimed water is not treated to the required levels, MGS would be required to arrange for sufficient treatment, either onsite or at the source facility, prior to its use in the cooling towers.

An additional consideration for reclaimed water is the presence of any ammonia or ammonia-forming compounds in the reclaimed water. All the condenser tubes at MGS contain copper alloys (aluminum brass) and can experience stress-corrosion cracking as a result of the interaction between copper and ammonia. Treatment for ammonia may include adding ferrous sulfate as a corrosion inhibitor or require ammonia-stripping towers to pretreat reclaimed water prior to use in the cooling towers (EPA 2001).

Four publicly owned treatment works (POTWs) were identified within a 15-mile radius of MGS, with a combined discharge capacity of 50 mgd. Figure H–6 shows the relative locations of these facilities to MGS.

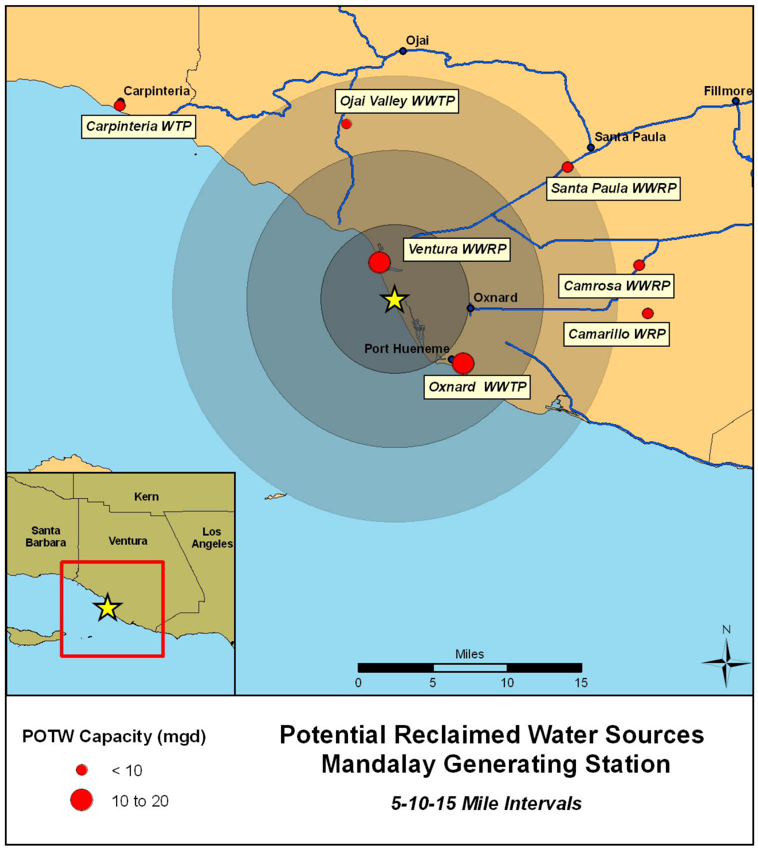

Figure H–6. Reclaimed Water Sources

- *City of Ventura Water Reclamation Facility (VWRF)—Ventura*
  Discharge volume: 14 mgd
  Distance: 2.5 miles NW
  Treatment level: Tertiary

  All wastewater at VWRF is treated to tertiary standards. Approximately 1.0 mgd is currently used for irrigation purposes in the vicinity. Facility staff indicated that demand is increasing as the area is developed and future uses may limit any capacity available to MGS as a makeup water source. Based on the current available capacity, however, VWRF could provide most of the makeup water (5–8 mgd) for freshwater cooling towers at MGS.

- *City of Oxnard Wastewater Treatment Plant—Oxnard*
  Discharge volume: 31 mgd
  Distance: 4 miles SE
  Treatment level: Secondary

  No information available. The existing capacity is sufficient to supply enough makeup water (5–8 mgd) for freshwater cooling towers at MGS, although arrangements for tertiary treatment would have to be made prior to its use.

Two other wastewater treatment plants—Ojai Valley and Santa Paula—lie within 10-15 miles of MGS. The combined capacity of these facilities (approximately 8 mgd) is equivalent to the total makeup demand required in freshwater towers at MGS, but would require transmission pipelines to all four facilities. If reclaimed water sources are pursued, the most practical options are the Ventura and Oxnard facilities.

The costs associated with installing transmission pipelines (excavation/drilling, material, labor), in addition to design and permitting costs, are difficult to quantify in the absence of a detailed analysis of various site-specific parameters that will influence the final configuration. The nearest facility with sufficient capacity to satisfy MGS's freshwater tower makeup demand (5–8 mgd) is located approximately 2.5 miles from the site (Ventura WRF). The area between the two facilities is not heavily developed. Installing a transmission pipeline would not face any significant obstacles in terms of infrastructure or right of way.

Based on data compiled for this study and others, the estimated installed cost of a 24-inch prestressed concrete cylinder pipe, sufficient to provide 8 mgd to MGS, is $250 per linear foot, or approximately $1.3 million per mile. Additional considerations, such as pump capacity and any required treatment, would increase the total cost.

Regulatory concerns beyond the scope of this investigation, however, may make reclaimed water (as a makeup water source) comparable or preferable to saltwater from the Pacific Ocean. Reclaimed water may enable MGS to eliminate potential conflicts with water discharge limitations or reduce PM10 emissions from the cooling tower, which is a concern given the South Coast air basin's current nonattainment status.

Use of freshwater (reclaimed water) as the makeup water source might enable MGS to avoid conflicts with effluent limitations that will likely result from installing wet cooling towers. The proximity of the Ventura WRF would appear to make this an attractive alternative combined with wet cooling towers, although MGS may choose to address effluent limitations in a different manner, such as pretreatment or discharge alteration (dilution).

At any facility where wet cooling towers are a feasible alternative, reclaimed water may be used as a makeup water source. The practicality of its use, however, depends on the overall cost, availability, and additional environmental benefit that may occur.

3.4.5 THERMAL EFFICIENCY

Wet cooling towers at MGS will increase the condenser inlet water temperature by a range of 3 to 16° F above the surface water temperature, depending on the ambient wet bulb temperature at the time. The generating units at MGS are designed to operate at the conditions described in Table H–12. The resulting monthly difference between once-through and wet cooling tower condenser inlet temperatures is described in Figure H–7.

Table H–12. Design Thermal Conditions

	Unit 1	Unit 2
Design backpressure (in. HgA)	1.5	1.5
Design water temperature (°F)	63	63
Turbine inlet temp (°F)	1,050	1,050
Turbine inlet pressure (psia)	2,150	2,150
Full load heat rate (BTU/kWh) [a]	9,375	9,450

[a] CEC 2002.

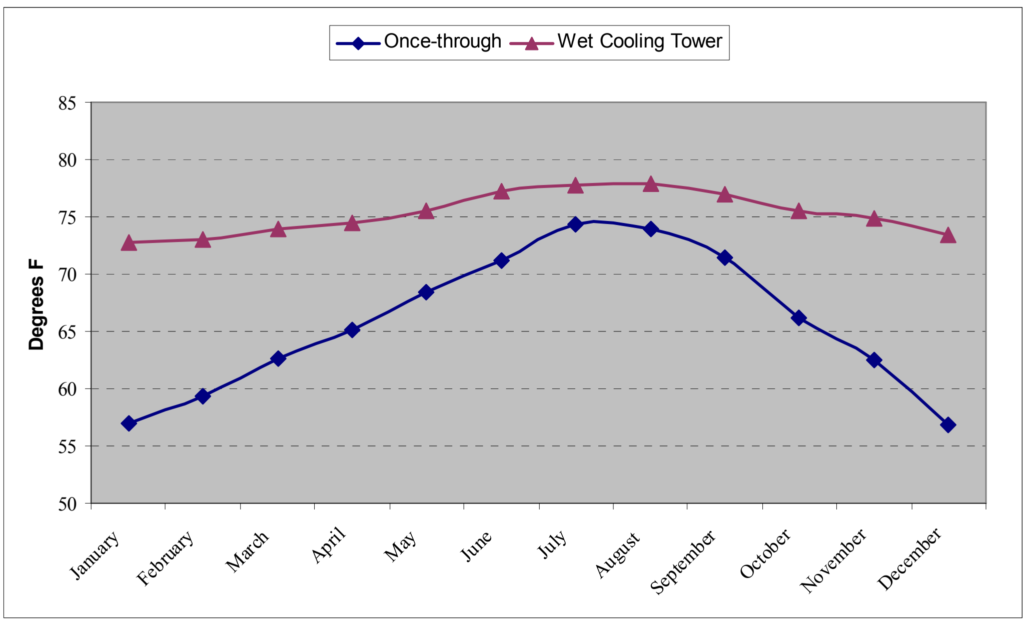

Figure H–7. Condenser Inlet Temperatures

Backpressures for the once-through and wet cooling tower configurations were calculated for each month using the design criteria described in the sections above and ambient climate data. In general, backpressures associated with the wet cooling tower were elevated by 0.3 to 0.8 inches HgA compared with the current once-through system (Figure H–8 and Figure H–10).

Heat rate adjustments were calculated by comparing the theoretical change in available energy that occurs at different turbine exhaust backpressures, assuming the thermal load and turbine inlet pressure remain constant, i.e., at the full load rating.[5] The relative change at different backpressures was compared with the value calculated for the design conditions (i.e., at design turbine inlet and exhaust backpressures) and plotted as a percentage of the full load operating heat rate to develop estimated correction curves (Figure H–9 and Figure H–11).

The difference between the estimated once-through and closed-cycle heat rates for each month represents the approximate heat rate increase that would be expected when converting to wet cooling towers.

Table H–13 summarizes the annual average heat rate increase for each unit as well as the increase associated with the peak demand period of July-August-September. Monthly values were used to calculate the monetized value of these heat rate changes (Section 4.6). Month-by-month calculations are presented in Appendix A.

Table H–13. Summary of Estimated Heat Rate Increases

	Unit 1	Unit 2
Peak (July-August-September)	0.43%	0.43%
Annual average	0.73%	0.73%

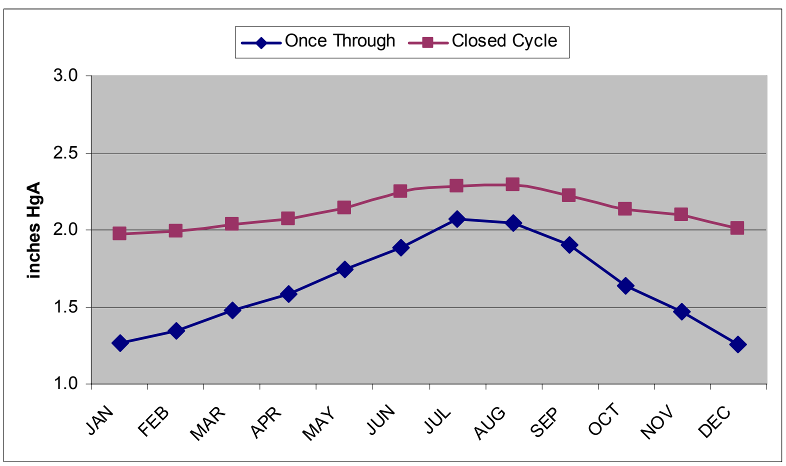

Figure H–8. Estimated Backpressures (Unit 1)

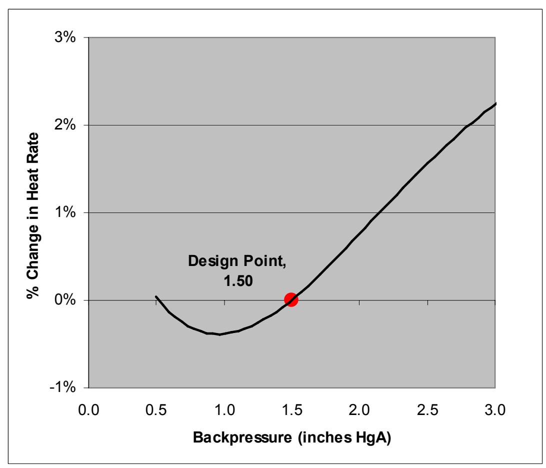

Figure H–9. Estimated Heat Rate Correction (Unit 1)

[5] Changes in thermal efficiency estimated for MGS are based on the design specifications provided by the facility. This may not reflect system modifications that might influence actual performance. In addition, the age of the units and the operating protocols used by MGS might result in different calculations.

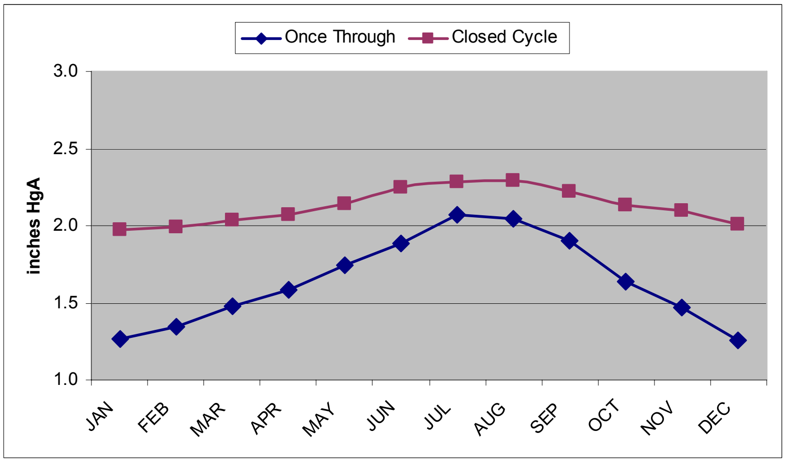

Figure H–10. Estimated Backpressures (Unit 2)

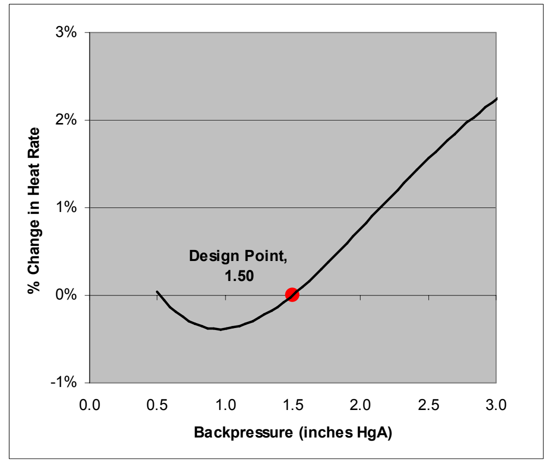

Figure H–11. Estimated Heat Rate Correction (Unit 2)

4.0 RETROFIT COST ANALYSIS

The wet cooling system retrofit estimate for MGS is based on incorporating conventional wet cooling towers as a replacement for the existing once-through system for each unit. Standard cost elements for this project include the following:

- Direct (cooling tower installation, civil/structural, mechanical, piping, electrical, and demolition)
- Indirect (smaller project costs not itemized)
- Contingency (allowance for unknown project variables)
- Revenue loss from shutdown (net loss in revenue during construction phase)
- Operations and maintenance (non–energy related cooling tower operations)
- Energy penalty (includes increased parasitic use from fans and pumps as well as decreased thermal efficiency)

The cost analysis does not include allowances for elements that are not quantified in this study, such as land acquisition, effluent treatment, or air emission reduction credits. The methodology used to develop cost estimates is discussed in Chapter 5.

4.1 COOLING TOWER INSTALLATION

In general, the cooling tower configuration selected for MGS conforms to a typical design; no significant variations from a conventional arrangement were needed. Table H–14 summarizes the design-and-build cost estimate for each tower developed by vendors, inclusive of all labor and management required for their installation.

Table H–14. Wet Cooling Tower Design-and-Build Cost Estimate

	Unit 1	Unit 2	MGS total
Number of cells	7	7	**14**
Cost/cell ($)	571,429	571,429	**571,429**
Total MGS D&B cost ($)	**4,000,000**	**4,000,000**	**8,000,000**

4.2 OTHER DIRECT COSTS

A significant portion of wet cooling tower installation costs result from the various support structures, materials, equipment and labor necessary to prepare the cooling tower site and connect the towers to the condenser. At MGS, these costs comprise approximately 50 percent of the initial capital cost. Line item costs are detailed in Appendix B.

Deviations from or additions to the general cost elements discussed in Chapter 5 are discussed below. Other direct costs (non–cooling tower) are summarized in Table H–15.

- *Civil, Structural, and Piping*
  The MGS site configuration allows each tower to be located within relative proximity to the generating unit it services.
- *Mechanical and Electrical*
  Initial capital costs in this category reflect the new pumps (four total) to circulate cooling water between the towers and condensers. No new pumps are required to provide makeup water from Channel Islands Harbor. Electrical costs are based on the battery limit after the main feeder breakers.
- *Demolition*
  No demolition costs are required.

Table H–15. Summary of Other Direct Costs

	Equipment ($)	Bulk material ($)	Labor ($)	MGS total ($)
Civil/structural/piping	2,900,000	8,200,000	6,700,000	**17,800,000**
Mechanical	4,300,000	0	400,000	**4,700,000**
Electrical	1,100,000	1,500,000	1,100,000	**3,700,000**
Demolition	0	0	0	**0**
Total MGS other direct costs	**8,300,000**	**9,700,000**	**8,200,000**	**26,200,000**

4.3 INDIRECT AND CONTINGENCY

Indirect costs are calculated as 25 percent of all direct costs (civil/structural, mechanical, electrical, demolition, and cooling towers).

An additional allowance is included for condenser water box and tube sheet reinforcement to withstand the increased pressures associated with a recirculating system. Each condenser may require reinforcement of the tube sheet bracing with 6-inch x 1-inch steel, and water box reinforcement/replacement with 5/8-inch carbon steel. Based on the estimates outlined in Chapter 5, a conservative estimate of 5 percent of all direct costs is included to account for possible condenser modifications.

The contingency cost is calculated as 25 percent of the sum of all direct and indirect costs, including condenser reinforcement. At MGS, potential costs in this category include relocating or demolishing small buildings and structures and potential interferences from underground structures.

Soils were not characterized for this analysis. MGS is situated at sea level adjacent to the Pacific Ocean. Seawater intrusion or the instability of sandy soils may require additional pilings to support any large structures built at the site. Initial capital costs are summarized in Table H–16.

Table H–16. Summary of Initial Capital Costs

	Cost ($)
Cooling towers	8,000,000
Civil/structural/piping	17,800,000
Mechanical	4,700,000
Electrical	3,700,000
Demolition	0
Indirect cost	8,500,000
Condenser modification	1,700,000
Contingency	11,100,000
Total MGS capital cost	**55,500,000**

4.4 SHUTDOWN

A portion of the work relating to installing wet cooling towers can be completed without significant disruption to the operations of MGS. Units will be offline depending on the length of time it takes to integrate the new cooling system and conduct acceptance testing. For MGS, a conservative estimate of 4 weeks per unit was developed. Based on 2006 generating output, however, no shutdown is forecast for either unit. Therefore, the cost analysis for MGS does not include any loss of revenue associated with shutdown at MGS.

This analysis did not consider shutdown with respect to the required availability of a particular generating unit, nor can it automatically be assumed that the generating profile for 2006 will be the same in each subsequent year. Net output data from 2006 may not reflect any contractual obligations that mandate a particular unit's availability during a given time period.

4.5 OPERATIONS AND MAINTENANCE

Operations and maintenance (O&M) costs for a wet cooling tower system at MGS include routine maintenance activities; chemicals and treatment systems to control fouling and corrosion in the towers; management and labor; and an allowance for spare parts and replacement. Annual costs are calculated based on the combined tower flow rate using a base cost of $4.00/gpm in Year 1 and $5.80/gpm in Year 12, with an annual escalator of 2 percent (USEPA 2001). Year 12 costs increase based on the assumption that maintenance needs, particularly for spare parts and replacements, will be greater for years 12–20. Annual O&M costs, based on the design circulating water flow for the two cooling towers at MGS (167,400 gpm), are presented in Table H–17. These costs reflect maximum operation.

Table H-17. Annual O&M Costs (Full Load)

	Year 1 cost ($)	Year 12 cost ($)
Management/labor	167,400	242,730
Service/parts	267,840	388,368
Fouling	234,360	339,822
Total MGS O&M cost	**669,600**	**970,920**

4.6 ENERGY PENALTY

The energy penalty is divided into two components: increased parasitic use from the added electrical demand from tower fans and pumps; and the decrease in thermal efficiency from elevated turbine backpressures. Monetizing the energy penalty at MGS requires some assumption as to how the facility will choose to alter its operations to compensate for these changes, if at all. One option would be to accept the reduced amount of revenue-generating electricity available for sale and absorb the economic loss ("production loss option"). A second option would be to increase the firing rate to the turbine (i.e., consume more fuel) and produce the same amount of revenue-generating electricity as had been obtained with the once-through cooling system ("increased fuel option"). The degree to which a facility is able, or prefers, to operate at a higher firing rate, however, produces the more likely scenario—some combination of the two.

Ultimately, the manner in which MGS would alter operations to address efficiency changes is driven by considerations unknown to this study (e.g., corporate strategy, contractual obligations, operating protocols and turbine pressure tolerances). In all summary cost estimates, this study calculates the energy penalty's monetized value by assuming the facility will use the increased fuel option to compensate for reduced efficiency and generate the amount of electricity equivalent to the estimated shortfall. With this option, the energy penalty is equivalent to the financial cost of additional fuel and is nominally less costly than the production loss option. This option, however, may not reflect long-term costs such as increased maintenance or system degradation that may result from continued operation at a higher-than-designed turbine firing rate. [6]

The energy penalty for MGS is calculated by first estimating the increased parasitic demand from the cooling tower pumps and fans, expressed as a percentage of each unit's rated capacity. Likewise, the change in the unit's heat rate is also expressed as a capacity percentage.

[6] Increasing the firing rate will raise the water temperature exiting the condenser. The cooling towers are designed with a maximum water return temperature, typically 120° F. Depending on the system's operating conditions, a facility may be limited in the degree to which it can alter the thermal input without compromising the cooling tower's performance.

4.6.1 INCREASED PARASITIC USE (FANS AND PUMPS)

Depending on ambient conditions or the operating load at a given time, MGS may be able to take one or more cooling tower cells offline and still obtain the required level of cooling. This would also reduce the cumulative electrical demand from the fans. For the purposes of this study, however, operations are evaluated at the design conditions, i.e., full load; no allowance is made for seasonal changes. The increased electrical demand from cooling tower fan operation is summarized in Table H–18.

Table H–18. Cooling Tower Fan Parasitic Use

	Tower 1	Tower 2	MGS total
Units served	Unit 1	Unit 2	--
Generating capacity (MW)	215	215	**430**
Number of fans (one per cell)	7	7	**14**
Motor power per fan (hp)	211	211	--
Total motor power (hp)	1,474	1,474	**2,947**
MW total	1.10	1.10	**2.20**
Fan parasitic use (% of capacity)	**0.51%**	**0.51%**	**0.51%**

Additional circulating water pump capacity for the wet cooling towers will also increase the parasitic electricity usage at MGS. Makeup water will continue to be withdrawn from the Pacific Ocean with one of the existing circulating water pumps; the remaining pumps will be retired.

The net increase in pump-related parasitic usage is the difference between the new wet cooling tower configuration (new plus retained pumps) and the existing once-through configuration. For calculation purposes, this study assumes full-load operation to estimate the cost of increased parasitic use. Final estimates, therefore, allocate the retained pump's electrical demand to each tower based on the proportion of the facility's generating capacity it services. Operating fewer towers or tower cells will alter the allocation of the retained pump's electrical demand, but not the total demand.

Because one of the main design assumptions maintains the existing flow rate through each condenser, the new circulating pumps are single speed and are assumed to operate at their full rated capacity when in use. The increased electrical demand associated with cooling tower pump operation is summarized in Table H–19.

Table H–19. Cooling Tower Pump Parasitic Use

	Tower 1	Tower 2	MGS total
Units served	Unit 1	Unit 2	--
Generating capacity (MW)	215	215	**430**
Existing pump configuration (hp)	1,200	1,200	**2,400**
New pump configuration (hp)	2,345	2,345	**4,691**
Difference (hp)	1,145	1,145	**2,291**
Difference (MW)	0.9	0.9	**1.7**
Net pump parasitic use (% of capacity)	**0.40%**	**0.40%**	**0.40%**

4.6.2 HEAT RATE CHANGE

Heat rate adjustments were calculated based on each month's ambient climate conditions and reflect the estimated difference between operations with once-through and wet cooling tower systems. As noted above, the energy penalty analysis assumes MGS will increase its fuel consumption to compensate for lost efficiency and the increased parasitic load from fans and pumps. The higher turbine firing rate will increase the thermal load rejected to the condenser, which, in turn, results in a higher backpressure value and corresponding increase in the heat rate. No data are available describing the changes in turbine backpressures above the design thermal loads. For the purposes of monetizing the energy penalty only, this study conservatively assumed an additional increase in the heat rate of 0.5 percent at the higher firing rate; the actual effect at MGS may be greater or less. Changes in the heat rate for each unit at MGS are presented in Figure H–12 and Figure H–13.

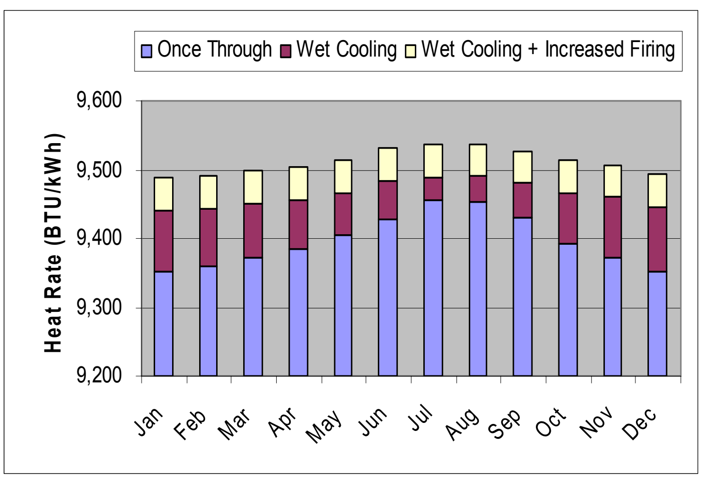

Figure H–12. Estimated Heat Rate Change (Unit 1)

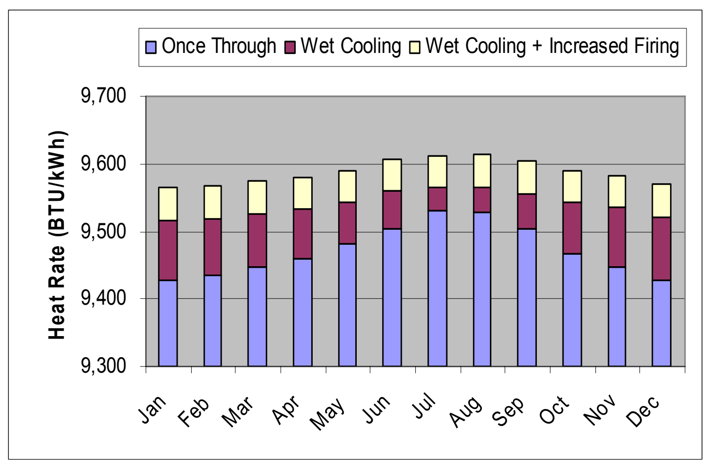

Figure H–13. Estimated Heat Rate Change (Unit 2)

4.6.3 CUMULATIVE ESTIMATE

Using the increased fuel option, the energy penalty's cumulative value is obtained by first calculating the relative costs of generation ($/MWh) for the once-through system and the wet cooling system adjusted for a higher turbine firing rate. The cost of generation for MGS is based on the relative heat rates developed in Section 3.4.2 and the average monthly wholesale natural gas cost ($/MMBTU) (ICE 2006a). The difference between these two values represents the monthly increased cost, per MWh, that results from converting to wet cooling towers. This value is then applied to the net MWh generated for the each month and summed to calculate the annual cost.

Based on 2006 output data, the Year 1 energy penalty for MGS will be approximately $162,000 million. In contrast, the energy penalty's value calculated with the production loss option would be approximately $303,000 million. Together, these values represent the range of potential energy penalty costs for MGS. Table H–20 and Table H–21 summarize the energy penalty estimates for each unit using the increased fuel option.

Table H–20. Unit 1 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	9,352	56.11	9,489	56.93	0.82	0	0
February	5.50	9,359	51.47	9,491	52.20	0.73	1,178	854
March	4.75	9,372	44.52	9,498	45.12	0.60	4,873	2,927
April	4.75	9,385	44.58	9,504	45.14	0.57	2,938	1,664
May	4.75	9,406	44.68	9,514	45.19	0.51	19,809	10,165
June	5.00	9,428	47.14	9,531	47.66	0.52	18,842	9,747
July	6.50	9,456	61.46	9,536	61.99	0.52	67,427	35,310
August	6.50	9,452	61.44	9,538	62.00	0.56	14,628	8,156
September	4.75	9,429	44.79	9,527	45.25	0.46	18,623	8,659
October	5.00	9,391	46.96	9,513	47.57	0.61	0	0
November	6.00	9,371	56.23	9,507	57.04	0.81	0	0
December	6.50	9,352	60.79	9,494	61.71	0.92	0	0
							Unit 1 total	**77,482**

Table H–21. Unit 2 Energy Penalty—Year 2

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	9,427	56.56	9,564	57.39	0.82	0	0
February	5.50	9,434	51.89	9,567	52.62	0.73	0	0
March	4.75	9,447	44.87	9,574	45.48	0.61	0	0
April	4.75	9,460	44.93	9,580	45.50	0.57	0	0
May	4.75	9,481	45.04	9,590	45.55	0.52	17,699	9,153
June	5.00	9,503	47.52	9,607	48.04	0.52	17,322	9,030
July	6.50	9,531	61.95	9,613	62.48	0.53	69,334	36,592
August	6.50	9,528	61.93	9,614	62.49	0.56	22,641	12,722
September	4.75	9,505	45.15	9,603	45.62	0.47	37,003	17,339
October	5.00	9,466	47.33	9,590	47.95	0.62	0	0
November	6.00	9,446	56.68	9,583	57.50	0.82	0	0
December	6.50	9,427	61.28	9,570	62.20	0.93	0	0
							Unit 2 total	**84,836**

4.7 NET PRESENT COST

The Net Present Cost (NPC) of a wet cooling system retrofit at MGS is the sum of all annual expenditures over the project's 20-year life span discounted according to the year in which the expense is incurred and the selected discount rate. The NPC represents the total change in revenue streams, in 2007 dollars, that MGS can expect over 20 years as a direct result of converting to wet cooling towers. The following values were used to calculate the NPC at a 7 percent discount rate:

- *Capital and Start-up.* Includes all capital, indirect, contingency, and shutdown costs. All costs in this category are incurred in Year 0. (See Table H–16.)
- *Annual O&M.* Base cost values for Year 1 and Year 12 are adjusted for subsequent years using a 2 percent year-over-year escalator. Because MGS has a relatively low capacity utilization factor, O&M costs for the NPC calculation were estimated at 35 percent of their maximum value. (See Table H–17.)
- *Annual Energy Penalty.* Insufficient information is available to this study to forecast future generating output at MGS. In lieu of annual estimates, this study uses the net MWh output from 2006 as the calculation basis for Years 1 through 20. Wholesale prices include a year-over-year price escalator of 5.8 percent (based on the Producer Price Index). The energy penalty values are based on the increased fuel option discussed in Section 4.6. (See Table H–20 and Table H–21.)

Using these values, the NPC_{20} for MGS is $61 million. Appendix C contains detailed annual calculations used to develop this cost.

4.8 ANNUAL COST

The annual cost incurred by MGS for a wet cooling tower retrofit is the sum of annual amortized capital costs plus the annual average of O&M and energy penalty expenditures. Capital costs are amortized at a 7 percent discount rate over 20 years. O&M and energy penalty costs are calculated in the same manner as for the NPC_{20} (Section 4.7). Revenue losses from a construction-related shutdown, if any, are incurred in Year 0 only and not included in the annual cost summarized in Table H–22.

Table H–22. Annual Cost

Discount rate	Capital Cost ($)	Annual O&M ($)	Annual energy penalty ($)	Annual cost ($)
7.00%	5,200,000	300,000	300,000	**5,800,000**

4.9 COST-TO-GROSS REVENUE COMPARISON

Limited financial data are available to conduct a detailed analysis of the economic impact that a wet cooling system retrofit will have on MGS's annual revenues. The facility's gross annual revenue can be approximated using 2006 net generating data (CEC 2006) and average wholesale prices for electricity as recorded at the SP 15 trading hub (ICE 2006b). This estimate, therefore, does not reflect any changes that may result from different wholesale prices or contract agreements that may increase or decrease the gross revenue summarized below, nor does it account for annual fixed revenue requirements or other variable costs.

The estimate of gross annual revenue from electricity sales at MGS is a straightforward calculation that multiplies the monthly wholesale cost of electricity by the amount generated for the particular month. The estimated gross revenue for MGS is summarized in Table H–23. A comparison of annual costs to annual gross revenue is summarized in Table H–24.

Table H–23. Estimated Gross Revenue

	Wholesale price ($/MWh)	2006 net output (MWh)		Estimated gross revenue ($)		
		Unit 1	Unit 2	Unit 1	Unit 2	MGS total
January	66	0	0	0	0	**0**
February	61	1,178	0	71,858	0	**71,858**
March	51	4,873	0	248,523	0	**248,523**
April	51	2,938	0	149,838	0	**149,838**
May	51	19,809	17,699	1,010,259	902,649	**1,912,908**
June	55	18,842	17,322	1,036,310	952,710	**1,989,020**
July	91	67,427	69,334	6,135,857	6,309,394	**12,445,251**
August	73	14,628	22,641	1,067,844	1,652,793	**2,720,637**
September	53	18,623	37,003	987,019	1,961,159	**2,948,178**
October	57	0	0	0	0	**0**
November	66	0	0	0	0	**0**
December	67	0	0	0	0	**0**
MGS total		**148,318**	**163,999**	**10,707,508**	**11,778,705**	**22,486,213**

Table H–24. Cost-Revenue Comparison

Estimated gross annual revenue ($)	Initial capital		O&M		Energy penalty		Total annual cost	
	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross
22,500,000	5,200,000	23	300,000	1.3	300,000	1.3	**5,800,000**	**26**

5.0 OTHER TECHNOLOGIES

Within the scope of this study, and using the OPC resolution's stated goal of reducing impingement and entrainment by 90–95 percent as a benchmark, the effectiveness of other technologies commonly used to address such impacts could not be conclusively determined for use at MGS. As with many existing facilities, the site's location and configuration complicate the use of some technologies that might be used successfully elsewhere. A more detailed analysis that also comprises a biological evaluation may determine the applicability of one or more of these technologies to MGS. A brief summary of these technologies' applicability follows.

5.1 MODIFIED RISTROPH SCREENS—FINE MESH

The principal concern with this technology is the successful return of viable organisms captured on the screens to the source water body. MGS currently withdraws its cooling water from Channel Islands Harbor. Returning any collected organisms to the harbor would be problematic because there is a high likelihood of reimpingement due to the flow patterns within the harbor and canal. There is also a question as to the long-term viability of fragile organisms (eggs and larvae) transported over the long distance from the facility to the harbor. Discharging organisms to the Pacific Ocean is not an option because many harbor species would be expected among the impinged organisms and may not survive in the open ocean. Successful deployment of this technology might be feasible with a better understanding of the biological conditions in Channel Islands Harbor and a detailed evaluation of a proposed return system.

5.2 BARRIER NETS

Placement of a barrier net at the entrance to the Edison Canal (West Channel Islands Boulevard) is not possible due to the likely conflicts with other uses of the marina. A barrier net could conceivably be placed at some distance closer to MGS without interfering with recreational boating and address impingement concerns. Barrier nets are ineffective as an entrainment reduction technology, however, and are not evaluated further in this study.

5.3 AQUATIC FILTRATION BARRIERS

Aquatic filtration barriers (AFBs) require large areas of relatively clean, low turbulence water in which to function properly. To protect the Edison Canal, MGS would require an AFB approximately 14,000 square feet in total area. The lack of sufficient cross currents at any potential location within the harbor would exacerbate any difficulties in keeping the material clean. The lack of available space within Channel Islands Harbor precludes the use of AFBs at MGS.

5.4 VARIABLE SPEED DRIVES

Variable speed drives (VSDs) were not considered for analysis at MGS because the technology alone cannot be expected to achieve the desired level of reductions in impingement and entrainment, nor could it be combined with another technology to yield the desired reductions.

Pumps that have been retrofitted with VSDs can reduce overall flow intake volumes by 10 to 50 percent over the current once-through configuration (USEPA 2001). The actual reduction, however, will vary based on the cooling water demand at different times of the year. At peak demand, the pumps will essentially function as standard circulating water pumps and withdraw water at the maximum rated capacity, thus negating any potential benefit. Use of VSDs may be an economically desirable option when pumps are retrofitted or replaced for other reasons, but they were not considered further for this study.

5.5 CYLINDRICAL FINE MESH WEDGEWIRE

Fine-mesh cylindrical wedgewire screens have not been deployed or evaluated at open coastal facilities for applications as large as would be required at MGS (approximately 250 mgd). To function as intended, cylindrical wedgewire screens must be submerged in a water body with a consistent ambient current of 0.5 feet per second (fps). Ideally, this current would be unidirectional so that screens may be oriented properly, and any debris impinged on the screens will be carried downstream when the airburst cleaning system is activated.

Fine-mesh wedgewire screens for MGS would be located offshore in the Pacific Ocean, west of the facility. Limited information regarding the subsurface currents in the near-shore environment near MGS is available. Data suggest that these currents are multidirectional, depending on the tide and season, and fluctuate in terms of velocity, with prolonged periods below 0.5 fps (SCCOOS 2006). To attain sufficient depth (approximately 20 feet) and an ambient current that might allow deployment, screens would need to be located 2,000 feet or more offshore. Discussions with vendors who design these systems indicated that distances over 1,000 to 1,500 feet become problematic due to the airburst system's inability to maintain adequate pressure for sufficient cleaning (Someah 2007). Together, these considerations preclude further evaluation of fine-mesh cylindrical wedgewire screens at MGS.

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Appendix A. Once-Through and Closed-Cycle Thermal Performance

		Unit 1			Unit 2		
		Once through	Closed cycle	Net increase	Once through	Closed cycle	Net increase
JAN	Backpressure (in. HgA)	1.26	1.98	**0.72**	1.26	1.98	**0.72**
	Heat rate Δ (%)	*-0.24*	*0.71*	***0.95***	*-0.24*	*0.71*	***0.95***
FEB	Backpressure (in. HgA)	1.35	1.99	**0.64**	1.35	1.99	**0.64**
	Heat rate Δ (%)	*-0.17*	*0.73*	***0.90***	*-0.17*	*0.73*	***0.90***
MAR	Backpressure (in. HgA)	1.48	2.04	**0.56**	1.48	2.04	**0.56**
	Heat rate Δ (%)	*-0.03*	*0.81*	***0.84***	*-0.03*	*0.81*	***0.84***
APR	Backpressure (in. HgA)	1.59	2.07	**0.49**	1.59	2.07	**0.49**
	Heat rate Δ (%)	*0.10*	*0.87*	***0.77***	*0.10*	*0.87*	***0.77***
MAY	Backpressure (in. HgA)	1.74	2.14	**0.40**	1.74	2.14	**0.40**
	Heat rate Δ (%)	*0.33*	*0.98*	***0.65***	*0.33*	*0.98*	***0.65***
JUN	Backpressure (in. HgA)	1.89	2.25	**0.36**	1.89	2.25	**0.36**
	Heat rate Δ (%)	*0.56*	*1.16*	***0.60***	*0.56*	*1.16*	***0.60***
JUL	Backpressure (in. HgA)	2.07	2.28	**0.21**	2.07	2.28	**0.21**
	Heat rate Δ (%)	*0.86*	*1.22*	***0.35***	*0.86*	*1.21*	***0.35***
AUG	Backpressure (in. HgA)	2.04	2.29	**0.24**	2.04	2.29	**0.24**
	Heat rate Δ (%)	*0.82*	*1.23*	***0.41***	*0.82*	*1.23*	***0.41***
SEP	Backpressure (in. HgA)	1.90	2.22	**0.32**	1.90	2.22	**0.32**
	Heat rate Δ (%)	*0.58*	*1.12*	***0.54***	*0.58*	*1.12*	***0.54***
OCT	Backpressure (in. HgA)	1.64	2.13	**0.50**	1.64	2.13	**0.50**
	Heat rate Δ (%)	*0.17*	*0.97*	***0.80***	*0.17*	*0.97*	***0.80***
NOV	Backpressure (in. HgA)	1.47	2.10	**0.62**	1.47	2.10	**0.62**
	Heat rate Δ (%)	*-0.04*	*0.91*	***0.94***	*-0.04*	*0.90*	***0.94***
DEC	Backpressure (in. HgA)	1.26	2.01	**0.75**	1.26	2.01	**0.75**
	Heat rate Δ (%)	*-0.24*	*0.76*	***1.01***	*-0.24*	*0.76*	***1.01***

Note: Heat rate delta represents change from design value calculated according to estimated ambient conditions for each month.

Appendix B. Itemized Capital Costs

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
CIVIL / STRUCTURAL / PIPING	--	--	--	--	--	--	--	--	--	--
Allocation for other accessories (bends, water hammers…)	lot	1	--	--	500,000	500,000	4,000.00	85	340,000	**840,000**
Allocation for pipe racks (approx 800 ft) and cable racks	t	80	--	--	2,500	200,000	17.00	105	142,800	**342,800**
Allocation for sheet piling and dewatering	lot	1	--	--	500,000	500,000	5,000.00	100	500,000	**1,000,000**
Allocation for testing pipes	lot	1	--	--	--	--	2,000.00	95	190,000	**190,000**
Allocation for Tie-Ins to existing condenser's piping	lot	1	--	--	250,000	250,000	2,000.00	85	170,000	**420,000**
Allocation for trust blocks	lot	1	--	--	50,000	50,000	500.00	95	47,500	**97,500**
Backfill for PCCP pipe (reusing excavated material)	m3	14,174	--	--	--	--	0.04	200	113,392	**113,392**
Bedding for PCCP pipe	m3	2,340	--	--	25	58,500	0.04	200	18,720	**77,220**
Bend for PCCP pipe 24" diam (allocation)	ea	24	--	--	3,000	72,000	20.00	95	45,600	**117,600**
Bend for PCCP pipe 72" diam (allocation)	ea	30	--	--	18,000	540,000	40.00	95	114,000	**654,000**
Building architectural (siding, roofing, doors, painting…etc)	ea	2	--	--	57,500	115,000	690.00	75	103,500	**218,500**
Butterfly valves 24" c/w allocation for actuator & air lines	ea	8	28,000	224,000	--	--	50.00	85	34,000	**258,000**
Butterfly valves 30" c/w allocation for actuator & air lines	ea	14	30,800	431,200	--	--	50.00	85	59,500	**490,700**
Butterfly valves 48" c/w allocation for actuator & air lines	ea	4	46,200	184,800	--	--	50.00	85	17,000	**201,800**
Butterfly valves 54" c/w allocation for actuator & air lines	ea	8	60,900	487,200	--	--	55.00	85	37,400	**524,600**
Butterfly valves 72" c/w allocation for actuator & air lines	ea	12	96,600	1,159,200	--	--	75.00	85	76,500	**1,235,700**
Check valves 24"	ea	4	40,000	160,000	--	--	12.00	85	4,080	**164,080**
Check valves 48"	ea	4	66,000	264,000	--	--	24.00	85	8,160	**272,160**
Concrete basin walls (all in)	m3	298	--	--	225	67,050	8.00	75	178,800	**245,850**
Concrete elevated slabs (all in)	m3	322	--	--	250	80,500	10.00	75	241,500	**322,000**
Concrete for transformers and oil catch basin (allocation)	m3	200	--	--	250	50,000	10.00	75	150,000	**200,000**
Concrete slabs on grade (all in)	m3	1,662	--	--	200	332,400	4.00	75	498,600	**831,000**
Ductile iron cement pipe 12" diam. for fire water line	ft	1,600	--	--	100	160,000	0.60	95	91,200	**251,200**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Excavation and backfill for fire line & make-up (using excavated material for backfill except for bedding)	m3	6,418	--	--	--	--	0.08	200	102,688	**102,688**
Excavation for PCCP pipe	m3	21,788	--	--	--	--	0.04	200	174,304	**174,304**
Fencing around transformers	m	50	--	--	30	1,500	1.00	75	3,750	**5,250**
Flange for PCCP joints 30"	ea	14	--	--	2,260	31,640	16.00	95	21,280	**52,920**
Flange for PCCP joints 72"	ea	16	--	--	9,860	157,760	25.00	95	38,000	**195,760**
Foundations for pipe racks and cable racks	m3	190	--	--	250	47,500	8.00	75	114,000	**161,500**
FRP flange 24"	ea	24	--	--	1,419	34,056	40.00	85	81,600	**115,656**
FRP flange 30"	ea	42	--	--	1,679	70,524	50.00	85	178,500	**249,024**
FRP flange 54"	ea	24	--	--	5,835	140,038	80.00	85	163,200	**303,238**
FRP flange 72"	ea	8	--	--	20,888	167,101	200.00	85	136,000	**303,101**
FRP pipe 24" diam.	ft	600	--	--	95	56,760	0.30	85	15,300	**72,060**
FRP pipe 48" diam.	ft	160	--	--	331	52,976	0.70	85	9,520	**62,496**
FRP pipe 72" diam.	ft	1,400	--	--	851	1,191,960	1.20	85	142,800	**1,334,760**
Harness clamp 24" c/w external testable joint	ea	80	--	--	1,715	137,200	14.00	95	106,400	**243,600**
Harness clamp 72" c/w internal testable joint	ea	190	--	--	2,440	463,600	18.00	95	324,900	**788,500**
Joint for FRP pipe 24" diam.	ea	20	--	--	901	18,012	35.00	85	59,500	**77,512**
Joint for FRP PIPE 48" diam.	ea	12	--	--	1,300	15,600	75.00	85	76,500	**92,100**
Joint for FRP pipe 72" diam.	ea	45	--	--	3,122	140,481	200.00	85	765,000	**905,481**
PCCP pipe 24" dia. For make-up	ft	1,500	--	--	98	147,000	0.50	95	71,250	**218,250**
PCCP pipe 72" diam.	ft	3,500	--	--	507	1,774,500	1.30	95	432,250	**2,206,750**
Riser (FRP pipe 30" diam X40 ft)	ea	14	--	--	14,603	204,442	100.00	85	119,000	**323,442**
Structural steel for building	t	160	--	--	2,500	400,000	20.00	105	336,000	**736,000**
CIVIL / STRUCTURAL / PIPING TOTAL	**--**	**--**	**--**	**2,910,400**	**--**	**8,228,101**	**--**	**--**	**6,653,994**	**17,792,495**
ELECTRICAL	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**
4.16 kv cabling feeding MCC's	m	1,000	--	--	75	75,000	0.40	85	34,000	**109,000**
4.16kV switchgear - 4 breakers	ea	1	250,000	250,000	--	--	150.00	85	12,750	**262,750**
480 volt cabling feeding MCC's	m	500	--	--	70	35,000	0.40	85	17,000	**52,000**
480V Switchgear - 1 breaker 3000A	ea	2	30,000	60,000	--	--	80.00	85	13,600	**73,600**
Allocation for automation and control	lot	1	--	--	500,000	500,000	5,000.00	85	425,000	**925,000**
Allocation for cable trays and duct banks	m	1,000	--	--	75	75,000	1.00	85	85,000	**160,000**
Allocation for lighting and lightning protection	lot	1	--	--	75,000	75,000	750.00	85	63,750	**138,750**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Dry Transformer 2MVA xxkV-480V	ea	2	100,000	200,000	--	--	100.00	85	17,000	**217,000**
Lighting & electrical services for pump house building	ea	2	--	--	50,000	100,000	500.00	85	85,000	**185,000**
Local feeder for 1200 HP motor 4160 V (up to MCC)	ea	4	--	--	40,000	160,000	150.00	85	51,000	**211,000**
Local feeder for 200 HP motor 460 V (up to MCC)	ea	14	--	--	18,000	252,000	150.00	85	178,500	**430,500**
Oil Transformer 10/13.33MVA xx-4.16kV	ea	2	190,000	380,000	--	--	150.00	85	25,500	**405,500**
Primary breaker(xxkV)	ea	4	45,000	180,000	--	--	60.00	85	20,400	**200,400**
Primary feed cabling (assumed 13.8 kv)	m	1,500	--	--	175	262,500	0.50	85	63,750	**326,250**
ELECTRICAL TOTAL	**--**	**--**	**--**	**1,070,000**	**--**	**1,534,500**	**--**	**--**	**1,092,250**	**3,696,750**
MECHANICAL	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**
Allocation for ventilation of buildings	ea	2	25,000	50,000	--	--	250.00	85	42,500	**92,500**
Cooling tower for unit 1	lot	1	4,000,000	4,000,000	--	--	--	--	--	**4,000,000**
Cooling tower for unit 2	lot	1	4,000,000	4,000,000	--	--	--	--	--	**4,000,000**
Overhead crane 50 ton in (in pump house) Including additional structure to reduce the span	ea	2	500,000	1,000,000	--	--	1,000.00	85	170,000	**1,170,000**
Pump 4160 V 1200 HP	ea	4	800,000	3,200,000	--	--	420.00	85	142,800	**3,342,800**
MECHANICAL TOTAL	**--**	**--**	**--**	**12,250,000**	**--**	**0**	**--**	**--**	**355,300**	**12,605,300**

Appendix C. Net Present Cost Calculation

Project year	Capital/start-up ($)	O & M ($)	Energy penalty ($)		Total ($)	Annual discount factor	Present value ($)
			Unit 1	Unit 2			
0	55,400,000	--	--	--	55,400,000	1	**55,400,000**
1	--	234,360	77,482	84,836	396,678	0.9346	**370,735**
2	--	239,047	81,999	89,782	410,828	0.8734	**358,817**
3	--	243,828	86,780	95,016	425,624	0.8163	**347,437**
4	--	248,705	91,839	100,555	441,099	0.7629	**336,514**
5	--	253,679	97,193	106,418	457,290	0.713	**326,047**
6	--	258,752	102,859	112,622	474,234	0.6663	**315,982**
7	--	263,927	108,856	119,188	491,971	0.6227	**306,351**
8	--	269,206	115,202	126,137	510,545	0.582	**297,137**
9	--	274,590	121,919	133,490	529,999	0.5439	**288,266**
10	--	280,082	129,026	141,273	550,381	0.5083	**279,759**
11	--	285,684	136,549	149,509	571,741	0.4751	**271,634**
12	--	346,618	144,509	158,225	649,353	0.444	**288,313**
13	--	353,551	152,934	167,450	673,935	0.415	**279,683**
14	--	360,622	161,850	177,212	699,684	0.3878	**271,338**
15	--	367,834	171,286	187,544	726,664	0.3624	**263,343**
16	--	375,191	181,272	198,477	754,941	0.3387	**255,698**
17	--	382,695	191,841	210,049	784,584	0.3166	**248,399**
18	--	390,349	203,025	222,295	815,668	0.2959	**241,356**
19	--	398,156	214,861	235,254	848,271	0.2765	**234,547**
20	--	406,119	227,388	248,970	882,476	0.2584	**228,032**
Total							**61,209,388**

I. Morro Bay Power Plant

Dynegy, Inc—Morro Bay, CA

Contents

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Appendices

1.0 GENERAL SUMMARY

This study did not analyze a potential retrofit of the existing once-through cooling system at Morro Bay Power Plant (MBPP), but instead updated an analysis conducted by Tetra Tech in 2002 at the request of the Central Coast Regional Water Quality Control Board (CCRWQCB). That study evaluated the cost and feasibility of alternative cooling system technologies, including wet and dry towers, for the proposed repowered facility that would have replaced the existing generating units with two combined cycle systems. The basis for this analysis, therefore, is not a conversion of the existing system but rather a comparison of the costs and logistical constraints that MBPP might face if the repowered units were designed with closed-cycle cooling instead continued use of the once-through system, as proposed by Duke Energy (former owner) in 2000.

Wet cooling towers are both technically and logistically feasible at MBPP, although a potential concern exists over the ability of a retrofitted MBPP to meet the PM_{10} emission goals established by the San Luis Obispo Air Pollution Control District, principally due to the increased emission from the towers themselves.

As designed, the wet cooling tower system selected as a replacement for MBPP conforms to all identified local use restrictions, such as noise, building height, and visual impact. Conventional (non plume-abated) wet cooling towers serve as the basis for analysis in this chapter. If required, plume-abated towers could be located at the site, although additional area would be required and would result in an increased tower capital cost (2 to 3 times the cost of conventional towers) as well as marginal increases in parasitic energy usage. The general design basis of the selected cooling tower, including plume abatement technologies, is discussed further in Section 3.2.3.

An energy penalty analysis was not developed for MBPP in the same manner as for other facilities in this study. Because this evaluation addresses the *proposed* MBPP repowering project, any changes to thermal efficiency that would occur with a closed-cycle system could be addressed in the initial design (e.g., reconfiguration of the condenser or including a turbine designed for different operating conditions). Comparing the efficiency of the current system to that of the repowered facility skews any resulting difference.

This study, therefore, is limited to a capital cost evaluation with an allowance for annual operations and maintenance (O&M) costs.

1.1 COST

Initial capital and Net Present Cost (NPC) costs associated with installing and operating wet cooling towers at MBPP are summarized in Table I–1. Annualized costs based on 20-year average values for the various cost elements are summarized in Table I–2.

Table I–1. Cumulative Cost Summary

Cost category	Cost ($)	Cost per MWh (rated capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Total capital and start-up [a]	94,012,500	10.40	46
NPC_{20} [b]	104,300,000	11.54	51

[a] Includes all costs associated with the cooling tower construction and installation and shutdown loss, if any.
[b] NPC_{20} includes all capital costs and operation and maintenance costs over 20 years discounted at 7 percent.

Table I–2. Annual Cost Summary

Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Capital and start-up	8,400,000	0.93	4.07
Operations and maintenance	1,000,000	0.11	0.48
Total MBPP annual cost	**9,400,000**	**1.04**	**4.55**

2.0 BACKGROUND

MBPP is a natural gas-fired steam electric generating facility in Morro Bay, San Luis Obispo County. The existing facility consists of four conventional units (Units 1-4) with a combined generating capacity of 1,002 MW. The repowered facility, as proposed, would include two new combined-cycle units, each comprised of two gas combustion turbines, one heat recovery steam generator (HRSG) and one steam turbine. The combined capacity of the new units is 1,200 MW, although this includes duct firing, which increases the operating heat rate, thus decreasing the unit's efficiency by approximately 4 percent. Without duct firing, each unit is rated at 516 MW for a facility total of 1,032 MW. Duct firing is typically used during peak demand periods when ambient conditions warrant.

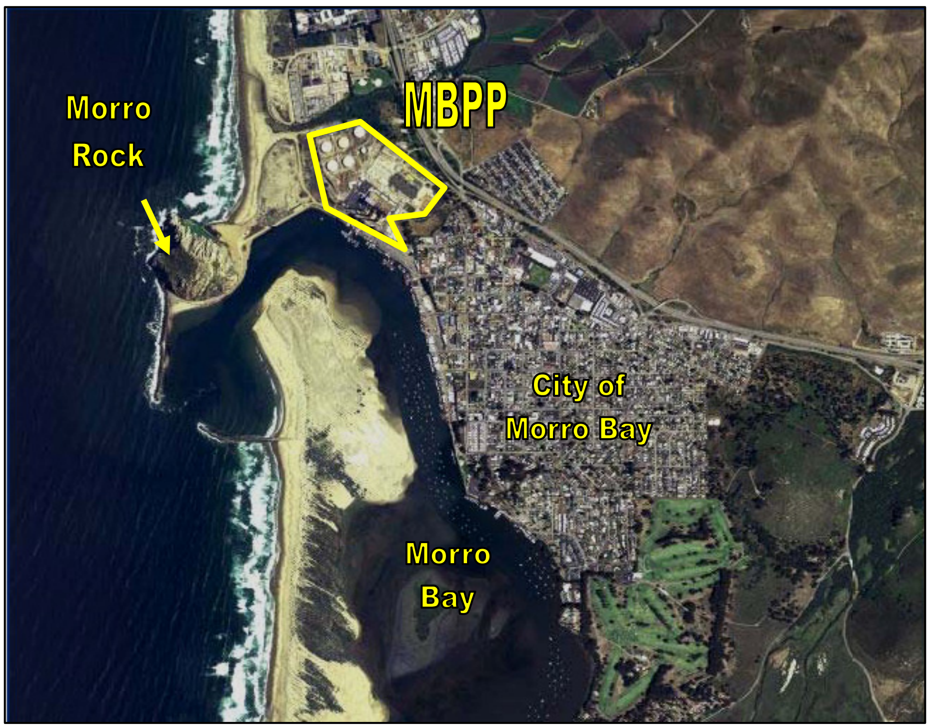

Figure I–1. General Vicinity of Morro Bay Power Plant

2.1 COOLING WATER SYSTEM

MBPP operates one cooling water intake structure (CWIS) to provide condenser cooling water to Units 1–4. The existing facility has a once-through cooling water capacity of 668 million gallons per day (MGD) and an average flow rate of 567 MGD. The proposed facility will have a design cooling water flow rate of 475 MGD and an average flow rate of 372 MGD.

Surface water withdrawals and discharges are permitted by National Pollutant Discharge Elimination System (NPDES) Permit CA CA0050610 as implemented by CCRWQCB Order R3-2001-0014. Cooling water is withdrawn through a surface intake located along the shoreline of Morro Bay, and discharged, along with other low-volume wastes, through a submerged outfall extending offshore into Estero Bay north of Morro Rock (Figure I–2).

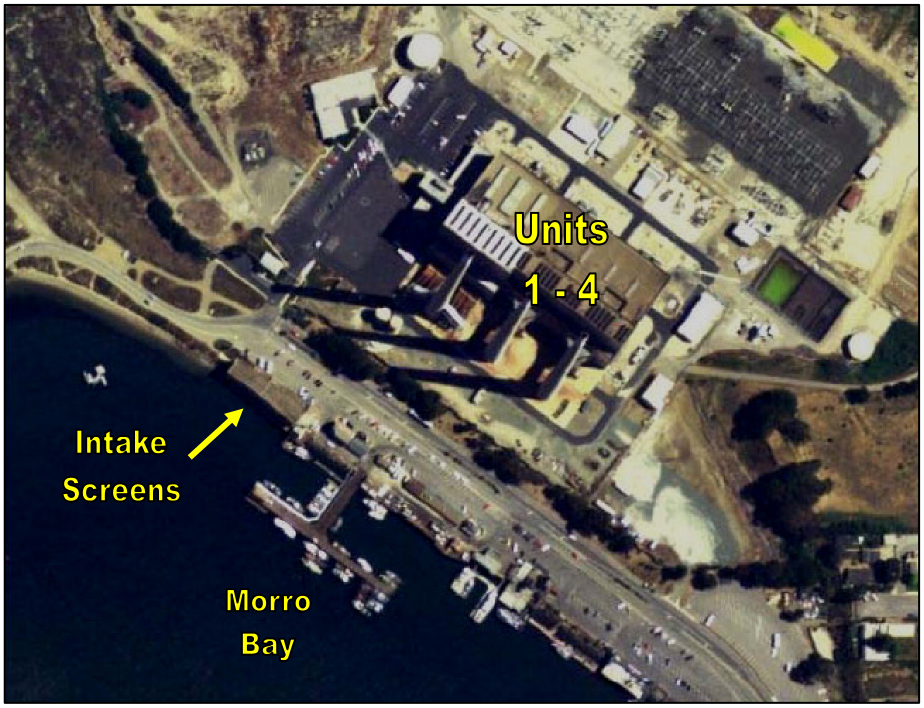

Figure I–2. Site View

2.2 SECTION 316(B) PERMIT COMPLIANCE

The CWIS currently in operation at MBPP does not use technologies generally considered to be effective at reducing impingement mortality and/or entrainment. Based on the low capacity utilization of the existing facility, the findings from the 2002 Tetra Tech report and the anticipated repowered facility in the next several years, the CCRWQCB did not include any numeric limitations or requirements regarding impingement mortality or entrainment in the current order. Instead, the order established a compliance schedule that required MBPP to conduct monitoring in Morro Bay with the intent of establishing a biological baseline and possibly evaluating the long-term effects of the facility's cooling water intake. MBPP was also required to comply with Comprehensive Demonstration Study schedule outlined in the Phase II rule (CCRWQCB 2007). It is not clear how the CCRWQCB intends to proceed with this requirement in light of the Second Circuit decision.

3.0 WET COOLING SYSTEM RETROFIT

3.1 OVERVIEW

This study evaluates saltwater cooling towers as part of a repowering of the existing MBPP, with the current source water (Morro Bay) continuing to provide makeup water to the facility. Use of wet cooling towers, combined with the reduced cooling water demand from the new combine-cycle units, results in a cooling water intake demand that is 98 percent lower than the current facility; rates of impingement and entrainment will decline by a similar proportion. Use of reclaimed water was considered for MBPP but not analyzed in detail because the available volume cannot serve as a replacement for once-through cooling water.

The wet cooling towers' configuration—their size, arrangement, and location—was based on best professional judgment (BPJ) using the criteria outlined in Chapter 5 and designed to meet the performance benchmarks in the most cost-effective manner. Information not available to this study that offers a more complete facility characterization may lead to different conclusions regarding the cooling towers' physical configuration.

Cost estimates are based on vendor quotes developed using the available information and the various design constraints identified at MBPP.

3.2 DESIGN BASIS

3.2.1 CONDENSER SPECIFICATIONS

Limited information describing the design specifications of the new combined-cycle units was available. For this study, the wet cooling tower conceptual design selected for MBPP is based on the standard assumptions regarding condenser thermal loads in combined-cycle units and basic information describing the existing condensers. It is noted, however, that the condenser specifications in the new units may be different from the current configuration (i.e., optimized for service with wet cooling towers).

Parameters used in the development of the cooling tower design are summarized in Table I–3.

Table I–3. Condenser Design Specifications

	Unit 1	Unit 2
Thermal load (MMBTU/hr)	1650	1650
Surface area (ft^2)	90,000	90,000
Condenser flow rate (gpm)	165,000	165,000
Tube material	Al Brass	Al Brass
Heat transfer coefficient (BTU/hr•ft^2•°F)	485	485
Cleanliness factor	0.85	0.85
Inlet temperature (°F)	56.5	56.5
Temperature rise (°F)	20.01	20.01
Steam condensate temperature (°F)	91.7	91.7
Turbine exhaust pressure (in. HgA)	1.5	1.5

3.2.2 AMBIENT ENVIRONMENTAL CONDITIONS

MBPP is located in San Luis Obispo County adjacent to Morro Bay. Surface water temperatures were obtained from the NOAA *Coastal Water Temperature Guide for Morro Bay, CA* (NOAA 2007). The wet bulb temperature used in the development of the overall cooling tower design was obtained from American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) publications. Data for coastal San Luis Obispo County indicate a 1 percent ambient wet bulb temperature of 64° F (ASHRAE 2006). An approach temperature of 12° F was selected based on the site configuration and vendor input. At the design wet bulb and approach temperatures, the cooling towers will yield “cold” water at a temperature of 76° F.

3.2.3 LOCAL USE RESTRICTIONS

3.2.3.1 NOISE

Limitations on noise are contained in the city of Morro Bay Noise Element to the General Plan. Noise is limited to 65 dBA in areas where outdoor uses may be affected. The wet cooling towers designed for this study include low noise fans in order to comply with this regulation.

3.2.3.2 PLUME ABATEMENT

Local zoning ordinances do not contain any specific criteria for addressing any impact associated with a wet cooling tower plume. Using the selection criteria for this study, plume abatement measures were not considered for MBPP; all towers are a conventional design. The plume from wet cooling towers at MBPP is not expected to adversely impact nearby infrastructure.

Community standards for assessing the visual impact associated with a cooling tower plume cannot be determined within the scope of this study. CEC siting guidelines and Coastal Act provisions evaluate the total size and persistence of a visual plume with respect to aesthetic standards for coastal resources; significant visual changes resulting from a persistent plume would likely be subject to additional controls.

Plume abatement towers for MBPP, if necessary, would be a feasible alternative given the relatively small size of the generating units and available land on which to locate them. The principal difference would be an escalation of the total cost (approximately 2 to 3 times the capital cost of conventional towers). The additional height required for plume-abated towers (approximately 15-20 feet) may conflict with height restrictions under local zoning ordinances, but this cannot be precisely determined.

3.2.3.3 DRIFT AND PARTICULATE EMISSIONS

Drift elimination measures that are considered best available control technology (BACT) are required for all cooling towers evaluated in this study, regardless of their location. State-of-the-art drift eliminators are included for each cooling tower cell at MBPP, with an accepted efficiency of 0.0005 percent. Because cooling tower PM_{10} emissions are a function of the drift rate, drift eliminators are also considered BACT for PM_{10} emissions from wet cooling towers. This efficiency can be verified by a proper in situ test, which accounts for site-specific climate, water, and operating conditions. Testing based on the Cooling Tower Institute's Isokinetic Drift Test Code is required at initial start-up on only one representative cell of each tower for an approximate cost of $60,000 per test, or approximately $120,000 for both cooling towers at MBPP (CTI 1994).

3.2.3.4 FACILITY CONFIGURATION AND AREA CONSTRAINTS

The area selected for wet cooling towers is the same as in the 2002 Tetra Tech report and is based on the proposed configuration of the new generating units in the area currently occupied by the fuel tanks. These tanks would be removed for the construction of the new combined-cycle units (Figure I–3). Cooling towers would be located in Area 1.

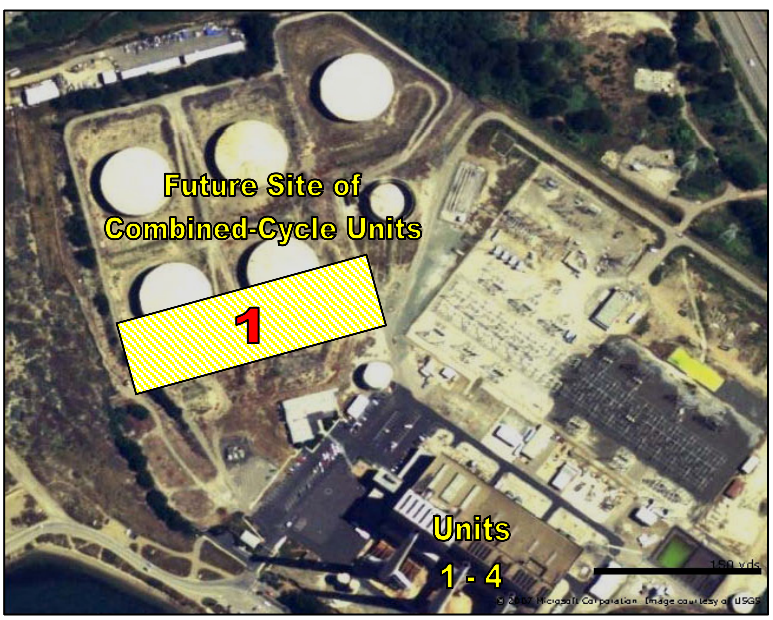

Figure I–3. Cooling Tower Siting Locations

3.3 CONCEPTUAL DESIGN

Based on the design constraints discussed above, two wet cooling towers were selected to replace the current once-through cooling system that serves Units 1 and 2 at MBPP. Each unit will be served by an independently-functioning tower with separate pump houses and pumps. Both towers at MBPP consist of conventional cells arranged in a multi-cell, back-to-back configuration.

3.3.1 SIZE

Each tower is constructed over a concrete collection basin 4 feet deep. The basin is larger than the tower structure's footprint, extending an additional 2 feet in each direction. The concrete used for construction is suitable for saltwater applications. The principal tower material is fiberglass reinforced plastic (FRP), with stainless steel fittings. These materials are more resistant to the higher corrosive effects of saltwater.

The size of each tower is primarily based on the thermal load rejected to the tower by the surface condenser and a 12° F approach to the ambient wet bulb temperature. The flow rate through each condenser remains unchanged.

General characteristics of the wet cooling towers selected for MBPP are summarized in Table I–4.

Table I–4. Wet Cooling Tower Design

	Tower 1 (Unit 1)	Tower 2 (Unit 2)
Thermal load (MMBTU/hr)	3300	3300
Circulating flow (gpm)	330,000	330,000
Number of cells	12	12
Tower type	Mechanical draft	Mechanical draft
Flow orientation	Counterflow	Counterflow
Fill type	Modular splash	Modular splash
Arrangement	Back-to-back	Back-to-back
Primary tower material	FRP	FRP
Tower dimensions (l x w x h) (ft)	324 x 96 x 54	324 x 96 x 54
Tower footprint with basin (l x w) (ft)	328 x 100	328 x 100

3.3.2 LOCATION

The initial site selection for each tower was based on the desire to locate each tower as close as possible to its respective generating unit to minimize the supply and return pipe distances and any increases in pump head and brake horsepower. Tower 1, serving Unit 1, is located at an approximate distance of 550 feet. Tower 2, serving Unit 2, is located at approximate distance of 200 feet. (Figure I–4).

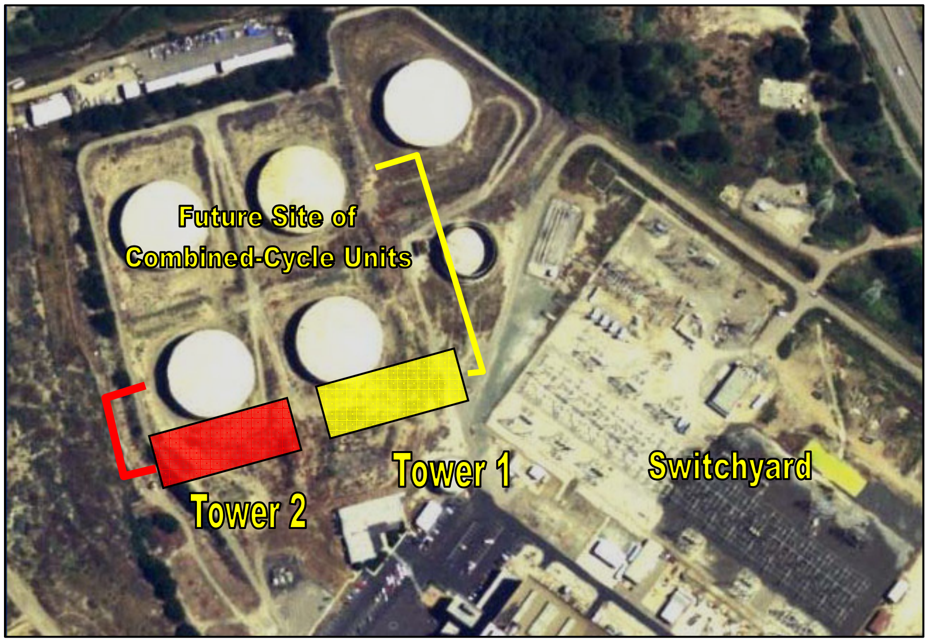

Figure I–4. Cooling Tower Locations

3.3.3 PIPING

The main supply and return pipelines to and from both towers will be located underground and made of prestressed concrete cylinder pipe (PCCP) suitable for saltwater applications. These pipes are sized at 72 inches in diameter. Pipes connecting the condensers to the supply and return lines are made of FRP and placed above ground on pipe racks. Above-ground placement avoids the potential disruption that may be caused by excavation in and around the power block. The condensers at MBPP are located at grade level, enabling a relatively straightforward connection.

All riser piping (extending from the foot of the tower to the level of water distribution) is constructed of FRP.

Appendix B details the total quantity of each pipe size and type for MBPP.

3.3.4 FANS AND PUMPS

Each tower cell uses an independent single-speed fan. The fan size and motor power are the same for each cell in each tower.

This analysis includes new pumps to circulate water between the condensers and cooling towers. Pumps are sized according to the flow rate for each tower, the relative distance between the towers and condensers, and the total head required to deliver water to the top of each cooling tower riser. A separate, multilevel pump house is constructed for each tower and sized to accommodate the motor control centers (MCCs) and appropriate electrical switchgear. The electrical installation includes all necessary transformers, cabling, cable trays, lighting, and lightning protection. A 50-ton overhead crane is also included to allow for pump servicing.

Fan and pump characteristics associated with wet cooling towers at MBPP are summarized in Table I–8. The net electrical demand of fans and new pumps is discussed further as part of the energy penalty analysis in Section Table I–5.

Table I–5. Cooling Tower Fans and Pumps

		Tower 1 (Unit 1)	Tower 2 (Unit 2)
Fans	Number	12	12
	Type	Single speed	Single speed
	Efficiency	0.95	0.95
	Motor power (hp)	211	211
Pumps	Number	2	2
	Type	50% recirculating Mixed flow Suspended bowl Vertical	50% recirculating Mixed flow Suspended bowl Vertical
	Efficiency	0.88	0.88
	Motor power (hp)	2,273	2,273

3.4 ENVIRONMENTAL EFFECTS

Converting the existing once-through cooling system at MBPP to wet cooling towers will significantly reduce the intake of seawater from Morro Bay and will presumably reduce impingement and entrainment by a similar proportion.

If MBPP retains its NPDES permit to discharge wastewater to the Pacific Ocean with a wet cooling tower system, it may have to address revised effluent limitations resulting from the substantial change in the discharge quantity and characteristics. Thermal impacts from the current once-through system, if any, will be minimized with a wet cooling system.

3.4.1 AIR EMISSIONS

MBPP is located in the South Central Coast air basin. Air emissions are permitted by the San Luis Obispo County Air Pollution Control District (SLOCAPCD) (Facility ID 8).

Drift volumes are expected to be within the range of 0.5 gallons for every 100,000 gallons of circulating water in the towers. At MBPP, this corresponds to a rate of approximately 1.6 gpm based on the maximum combined flow both two towers.

Total PM_{10} emissions from the MBPP cooling towers are a function of the number of hours in operation, the overall water quality in the tower, and the evaporation rate of drift droplets prior to deposition on the ground. Makeup water at MBPP will be obtained from the same source currently used for once-through cooling water (Morro Bay). At 1.5 cycles of concentration and assuming an initial TDS value of 35 parts per thousand (ppt), the water within the cooling towers will reach a maximum TDS level of roughly 53 ppt. Any drift droplets exiting the tower will have the same TDS concentration.

The cumulative mass emission of PM_{10} from MBPP will increase as a result of the direct emissions from the cooling towers themselves. Stack emissions of PM_{10}, as well as SO_x, NO_x, and other pollutants, will increase due to the drop in fuel efficiency, although the cumulative increase will depend on actual operations and emission control technologies currently in use. Maximum drift and PM_{10} emissions from the cooling towers are summarized in Table I–6.

Data summarizing the total facility emissions for these pollutants in 2005 are presented in Table I–7 (CARB 2005). In 2005, MBPP operated at an annual capacity utilization rate of 6.1 percent. Using this rate, the additional PM_{10} emissions from the cooling towers would increase the facility total by approximately 12 tons/year, or 100 percent. [1]

Table I–6. Full Load Drift and Particulate Estimates

	PM_{10} (lbs/hr)	PM_{10} (tons/year)	Drift (gpm)	Drift (lbs/hr)
Tower 1	22	95	0.8	413
Tower 2	22	95	0.8	413
Total MBPP PM_{10} and drift emissions	**44**	**190**	**1.60**	**826**

Table I–7. 2005 Emissions of SO_x, NO_x, PM_{10}

Pollutant	Tons/year
NO_x	49.5
SO_x	1.0
PM_{10}	11.8

3.4.2 MAKEUP WATER

The volume of makeup water required by both cooling towers at MBPP is the sum of evaporative loss and the blowdown volume required to maintain the circulating water in each tower at the design TDS concentration. Drift expelled from the towers represents an insignificant volume by comparison and is accounted for by rounding up evaporative loss estimates. Makeup water volumes are based on design conditions, and may fluctuate seasonally depending on climate conditions and facility operations. Wet cooling towers will reduce once-through cooling water withdrawals from Morro Bay by approximately 95 over the current design intake capacity.

[1] 2006 emission data are not currently available from the Air Resources Board website. For consistency, the comparative increase in PM10 emissions estimated here is based on the 2005 MBPP capacity utilization rate instead of the 2006 rate presented in Table I-1. All other calculations in this chapter use the 2006 value.

Table I–8. Makeup Water Demand

	Tower circulating flow (gpm)	Evaporation (gpm)	Blowdown (gpm)	Total makeup water (gpm)
Tower 1	330,000	2,800	5,400	8,200
Tower 2	330,000	2,800	5,400	8,200
Total MBPP makeup water demand	**660,000**	**5,600**	**10,800**	**16,400**

One circulating water pump, rated at 37,000 gpm, which is currently used to provide once-through cooling water to the facility, will be retained in a wet cooling system to provide makeup water to each cooling tower. The retained pump's capacity exceeds the makeup demand by approximately 21,000 gpm. Any excess capacity will be routed through a bypass conduit and returned to the wet well at a point located behind the intake screens. Recirculating the excess capacity in this manner reduces additional cost that would be incurred if new pumps were required while maintaining the desired flow reduction. The intake of new water, measured at the intake screens, will be equal to the cooling towers' makeup water demand. Figure I–5 presents a schematic of this configuration.

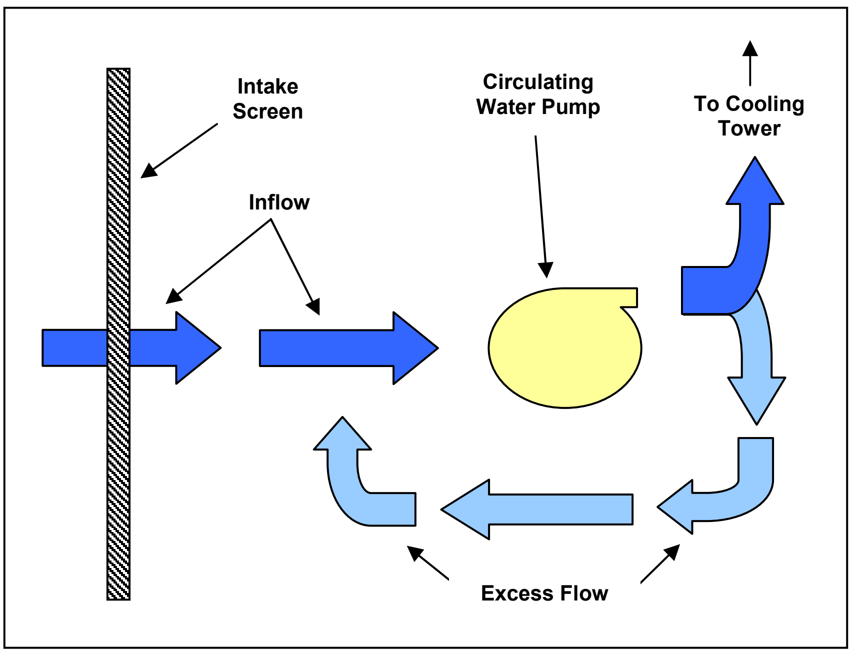

Figure I–5. Schematic of Intake Pump Configuration

The existing once-through cooling system at MBPP does not treat water withdrawn from Morro Bay, with the exception of screening for debris and larger organisms and periodic chlorination to control biofouling in the condenser tubes. Heat treatments are also periodically used to control mussel growth on pipes and condenser tubes by raising the circulating water temperature.

Conversion to a wet cooling tower system will not interfere with chlorination or heat treatment operations.

Makeup water will continue to be withdrawn from the Morro Bay.

The wet cooling tower system proposed for MBPP includes water treatment for standard operational measures, i.e., corrosion inhibitors, biocides, and anti-scaling agents. An allowance for these additional chemical treatments is included in annual O&M costs. It is assumed that the current once-through cooling water quality will be acceptable for use in a seawater cooling tower (with continued screening) and will not require any pretreatment to enable its use.

3.4.3 NPDES PERMIT COMPLIANCE

At maximum operation, wet cooling towers at MBPP will result in an effluent discharge of 15 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, regeneration wastes, and cleaning wastes. These low volume wastes may add an additional 0.5 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, MBPP will be required to modify its existing individual wastewater discharge (NPDES) permit. All wastewaters are discharged to the Estero Bay through a submerged conduit. The existing Order contains effluent limitations based on the 1997 Ocean Plan and the 1972 Thermal Plan.

MBPP will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities at 40 CFR 423.13(d)(1). These ELGs set numeric limitations for chromium (total) and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity.

The presence of chromium or zinc in the makeup water source may trigger ELG exceedances when concentrated in the cooling tower and discharged with the final effluent. Effluent limitations for cooling tower blowdown must be met at the point of discharge from the cooling tower prior to combination with any other waste stream. The potential for an exceedance could necessitate treatment of the blowdown for metals prior to discharge.

Assuming the same source water, any reasonable potential associated with wet cooling tower operations would likely increase and may require an effluent treatment system, such as filtration or precipitation technologies, to meet NPDES permit conditions. In the event treatment methods such as filtration or precipitation technologies are required to meet NPDES permit conditions, the initial capital cost may range from $2 to $5.50 per 1,000 gallons of treatment capacity, with annual costs of approximately $0.5 per gallon of capacity, depending on the method of treatment (FRTR 2002). Hazardous material disposal fees and permits would further increase costs.

Use of reclaimed water as the cooling tower makeup source has the potential to reduce or eliminate conflicts with effluent limitations. During its review of the Morro Bay Power Plant Project in 2004, the California Energy Commission determined that sufficient volumes of reclaimed water were not available in the vicinity of MBPP.

In the event treatment methods such as filtration or precipitation technologies were required to meet NPDES permit conditions, the initial capital cost may range from $2 to $5.50 per 1,000 gallons of treatment capacity with annual costs of approximately $0.5 per gallon of capacity, depending on the method of treatment (FRTR 2002). Hazardous material disposal fees and permits would further increase costs.

4.0 RETROFIT COST ANALYSIS

The wet cooling system retrofit estimate for MBPP is based on incorporating conventional wet cooling towers as a replacement for the existing once-through system for each unit. Standard cost elements for this project include the following:

- Direct (cooling tower installation, civil/structural, mechanical, piping, electrical, and demolition)
- Indirect (smaller project costs not itemized)
- Contingency (allowance for unknown project variables)
- Operations and maintenance (non–energy related cooling tower operations)

4.1 COOLING TOWER INSTALLATION

In general, the cooling tower configuration selected for MBPP conforms to a typical design; no significant variations from a conventional arrangement were needed. Table I–9 summarizes the design-and-build cost estimate for each tower developed by vendors, inclusive of all labor and management required for their installation.

Table I–9. Wet Cooling Tower Design-and-Build Cost Estimate

	Unit 1	Unit 2	MBPP total
Number of cells	12	12	**24**
Cost/cell ($)	566,667	566,667	12
Total MBPP D&B cost ($)	**6,800,000**	**6,800,000**	**13,600,000**

4.2 OTHER DIRECT COSTS

A significant portion of wet cooling tower installation costs result from the various support structures, materials, equipment and labor necessary to prepare the cooling tower site and connect the towers to the condenser. At MBPP, these costs comprise approximately 50 percent of the initial capital cost. Line item costs are detailed in Appendix A.

Deviations from or additions to the general cost elements discussed in Chapter 5 are discussed below. Other direct costs (non–cooling tower) are summarized in Table I–10.

- *Civil, Structural, and Piping*
  The MBPP site configuration allows each tower to be located within relative proximity to the generating unit it services.
- *Mechanical and Electrical*
  Initial capital costs in this category reflect the new pumps (four total) to circulate cooling water between the towers and condensers. No new pumps are required to provide makeup

water from Morro Bay. Electrical costs are based on the battery limit after the main feeder breakers.

- *Demolition*
  No demolition costs are required.

Table I–10. Summary of Other Direct Costs

	Equipment ($)	Bulk material ($)	Labor ($)	MBPP total ($)
Civil/structural/piping	4,500,000	13,500,000	12,000,000	**30,000,000**
Mechanical	6,000,000	0	700,000	**6,700,000**
Electrical	1,300,000	1,700,000	1,600,000	**4,600,000**
Demolition	0	0	0	**0**
Total MBPP other direct costs	**11,800,000**	**15,200,000**	**14,300,000**	**41,300,000**

4.3 INDIRECT AND CONTINGENCY

Indirect costs are calculated as 25 percent of all direct costs (civil/structural, mechanical, electrical, demolition, and cooling towers).

An additional allowance is included for condenser water box and tube sheet reinforcement to withstand the increased pressures associated with a recirculating system. Each condenser may require reinforcement of the tube sheet bracing with 6-inch x 1-inch steel, and water box reinforcement/replacement with 5/8-inch carbon steel. Based on the estimates outlined in Chapter 5, a conservative estimate of 5 percent of all direct costs is included to account for possible condenser modifications.

The contingency cost is calculated as 25 percent of the sum of all direct and indirect costs, including condenser reinforcement. At MBPP, potential costs in this category include relocating or demolishing small buildings and structures and potential interferences from underground structures.

Soils were not characterized for this analysis. MBPP is situated at sea level adjacent to Morro Bay with wetlands bordering the northern portion of the property. Seawater intrusion or the instability of marshy soils may require additional pilings to support any large structures built at the site. Initial capital costs are summarized in Table I–11.

Table I–11. Summary of Initial Capital Costs

	Cost ($)
Cooling towers	13,600,000
Civil/structural/piping	30,000,000
Mechanical	6,700,000
Electrical	4,600,000
Demolition	0
Indirect cost	13,700,000
Condenser modification	2,700,000
Contingency	17,800,000
Total MBPP capital cost	**89,100,000**

4.4 SHUTDOWN

No shutdown loss is associated with a new construction project.

4.5 OPERATIONS AND MAINTENANCE

Operations and maintenance (O&M) costs for a wet cooling tower system at MBPP include routine maintenance activities; chemicals and treatment systems to control fouling and corrosion in the towers; management and labor; and an allowance for spare parts and replacement. Annual costs are calculated based on the combined tower flow rate using a base cost of $4.00/gpm in Year 1 and $5.80/gpm in Year 12, with an annual escalator of 2 percent (USEPA 2001). Year 12 costs increase based on the assumption that maintenance needs, particularly for spare parts and replacements, will be greater for years 12–20. Annual O&M costs, based on the design circulating water flow for the two cooling towers at MBPP (330,400 gpm), are presented in Table I–12. These costs reflect maximum operation.

Table I–12. Annual O&M Costs (Full Load)

	Year 1 cost ($)	Year 12 cost ($)
Management/labor	330,000	478,500
Service/parts	528,000	765,600
Fouling	462,000	669,900
Total MBPP O&M cost	**1,320,000**	**1,914,000**

4.6 NET PRESENT COST

The Net Present Cost (NPC) of a wet cooling system retrofit at MBPP is the sum of all annual expenditures over the project's 20-year life span discounted according to the year in which the expense is incurred and the selected discount rate. The NPC represents the total change in revenue streams, in 2007 dollars, that MBPP can expect over 20 years as a direct result of converting to wet cooling towers. The following values were used to calculate the NPC at a 7 percent discount rate:

- *Capital and Start-up.* Includes all capital, indirect, contingency, and shutdown costs. All costs in this category are incurred in Year 0. (See Table I–11.)
- *Annual O&M.* Base cost values for Year 1 and Year 12 are adjusted for subsequent years using a 2 percent year-over-year escalator. Because MBPP (with combined cycle units) will have a higher capacity utilization factor than it currently has, O&M costs for the NPC calculation were estimated at 60 percent of their maximum value. (See Table I–12.)

Using these values, the NPC_{20} for MBPP is $104 million. Appendix B contains detailed annual calculations used to develop this cost.

4.7 ANNUAL COST

The annual cost incurred by MBPP for a wet cooling tower retrofit is the sum of annual amortized capital costs plus the annual average of O&M expenditures. Capital costs are amortized at a 7 percent discount rate over 20 years. O&M costs are calculated in the same manner as for the NPC_{20} (Section 4.7). Revenue losses from a construction-related shutdown, if any, are incurred in Year 0 only and not included in the annual cost summarized in Table I–13.

Table I–13. Annual Cost

Discount rate	Capital Cost ($)	Annual O&M ($)	Annual energy penalty ($)	Annual cost ($)
7.00%	8,400,000	1,000,000	0	**9,400,000**

4.8 COST-TO-GROSS REVENUE COMPARISON

Revenue cannot be estimated for the new combined-cycle facility. No comparison is made as part of this study.

5.0 OTHER TECHNOLOGIES

Within the scope of this study, and using the OPC resolution's stated goal of reducing impingement and entrainment by 90–95 percent as a benchmark, the effectiveness of other technologies commonly used to address such impacts could not be conclusively determined for use at MBPP. As with many existing facilities, the site's location and configuration complicate the use of some technologies that might be used successfully elsewhere. A more detailed analysis that also comprises a biological evaluation may determine the applicability of one or more of these technologies to MBPP. A brief summary of these technologies' applicability follows.

5.1 MODIFIED RISTROPH SCREENS—FINE MESH

The principal concern with this technology is the successful return of viable organisms captured on the screens to the source water body. MBPP currently withdraws its cooling water from Morro Bay. Returning any collected organisms to the harbor is feasible, but the circulating patterns in the bay would have to be characterized to understand how they might affect reimpingement of eggs and larvae. Successful deployment of this technology might be feasible with a better understanding of the biological conditions in Morro Bay and a detailed evaluation of a proposed return system.

5.2 BARRIER NETS

Placement of a barrier net at the entrance to Morro Bay or in front of the intake structures is not possible due to the likely conflicts with other uses of the marina. Barrier nets are ineffective as an entrainment reduction technology, however, and are not evaluated further in this study.

5.3 AQUATIC FILTRATION BARRIERS

The 2002 Tetra Tech report evaluated the feasibility of aquatic filtration barriers (AFBs) at Morro Bay, but concluded that performance data for the technology were insufficient to make a conclusive determination. The lack of available space within Morro Bay would appear to preclude the use of AFBs at MBPP.

5.4 VARIABLE SPEED DRIVES

Variable speed drives (VSDs) were not considered for analysis at MBPP because the technology alone cannot be expected to achieve the desired level of reductions in impingement and entrainment, nor could it be combined with another technology to yield the desired reductions. Pumps that have been retrofitted with VSDs can reduce overall flow intake volumes by 10 to 50 percent over the current once-through configuration (USEPA 2001). The actual reduction, however, will vary based on the cooling water demand at different times of the year. At peak demand, the pumps will essentially function as standard circulating water pumps and withdraw water at the maximum rated capacity, thus negating any potential benefit. Use of VSDs may be an economically desirable option when pumps are retrofitted or replaced for other reasons, but they were not considered further for this study.

5.5 CYLINDRICAL FINE MESH WEDGEWIRE

Fine-mesh cylindrical wedgewire screens have not been deployed or evaluated at open coastal facilities for applications as large as would be required at MBPP (approximately 250 mgd). To function as intended, cylindrical wedgewire screens must be submerged in a water body with a consistent ambient current of 0.5 feet per second (fps). Ideally, this current would be unidirectional so that screens may be oriented properly, and any debris impinged on the screens will be carried downstream when the airburst cleaning system is activated.

Fine-mesh wedgewire screens for MBPP would be located offshore in Estero Bay, west of the facility. No data are available describing the currents in this area. Thus, no determination can be made as to the potential effectiveness of cylindrical wedgewire screens at MBPP.

6.0 REFERENCES

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Appendix A. Once-Through and Closed-Cycle Thermal Performance

		Unit 1			Unit 2		
		Once through	Closed cycle	Net increase	Once through	Closed cycle	Net increase
JAN	Backpressure (in. HgA)	1.49	2.41	**0.92**	1.49	2.41	**0.92**
	Heat rate Δ (%)	*-0.03*	*3.38*	***3.41***	*-0.03*	*3.38*	***3.41***
FEB	Backpressure (in. HgA)	1.53	2.43	**0.90**	1.53	2.43	**0.90**
	Heat rate Δ (%)	*0.08*	*3.42*	***3.34***	*0.08*	*3.42*	***3.34***
MAR	Backpressure (in. HgA)	1.49	2.46	**0.97**	1.49	2.46	**0.97**
	Heat rate Δ (%)	*-0.03*	*3.55*	***3.58***	*-0.03*	*3.55*	***3.58***
APR	Backpressure (in. HgA)	1.46	2.47	**1.02**	1.46	2.47	**1.02**
	Heat rate Δ (%)	*-0.13*	*3.59*	***3.72***	*-0.13*	*3.59*	***3.72***
MAY	Backpressure (in. HgA)	1.49	2.54	**1.05**	1.49	2.54	**1.05**
	Heat rate Δ (%)	*-0.03*	*3.83*	***3.86***	*-0.03*	*3.83*	***3.86***
JUN	Backpressure (in. HgA)	1.55	2.58	**1.04**	1.55	2.58	**1.04**
	Heat rate Δ (%)	*0.14*	*3.97*	***3.83***	*0.14*	*3.97*	***3.83***
JUL	Backpressure (in. HgA)	1.63	2.61	**0.99**	1.63	2.61	**0.99**
	Heat rate Δ (%)	*0.39*	*4.06*	***3.67***	*0.39*	*4.06*	***3.67***
AUG	Backpressure (in. HgA)	1.69	2.65	**0.97**	1.69	2.65	**0.97**
	Heat rate Δ (%)	*0.59*	*4.20*	***3.61***	*0.59*	*4.20*	***3.61***
SEP	Backpressure (in. HgA)	1.69	2.63	**0.94**	1.69	2.63	**0.94**
	Heat rate Δ (%)	*0.59*	*4.12*	***3.53***	*0.59*	*4.12*	***3.53***
OCT	Backpressure (in. HgA)	1.65	2.58	**0.93**	1.65	2.58	**0.93**
	Heat rate Δ (%)	*0.45*	*3.95*	***3.50***	*0.45*	*3.95*	***3.50***
NOV	Backpressure (in. HgA)	1.57	2.54	**0.97**	1.57	2.54	**0.97**
	Heat rate Δ (%)	*0.19*	*3.83*	***3.63***	*0.19*	*3.83*	***3.63***
DEC	Backpressure (in. HgA)	1.49	2.49	**1.00**	1.49	2.49	**1.00**
	Heat rate Δ (%)	*-0.03*	*3.65*	***3.68***	*-0.03*	*3.65*	***3.68***

Note: Heat rate delta represents change from design value calculated according to estimated ambient conditions for each month.

Appendix B. Itemized Capital Costs

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
CIVIL / STRUCTURAL / PIPING	--	--	--	--	--	--	--	--	--	--
Allocation for other accessories (bends, water hammers…)	lot	1	--	--	500,000	500,000	4,000.00	106	424,000	**924,000**
Allocation for pipe racks (approx 800 ft) and cable racks	t	80	--	--	2,500	200,000	17.00	105	142,800	**342,800**
Allocation for sheet piling and dewatering	lot	1	--	--	500,000	500,000	5,000.00	100	500,000	**1,000,000**
Allocation for testing pipes	lot	1	--	--	--	--	2,000.00	95	190,000	**190,000**
Allocation for Tie-Ins to condenser's piping	lot	1	--	--	250,000	250,000	2,000.00	106	212,000	**462,000**
Allocation for trust blocks	lot	1	--	--	50,000	50,000	500.00	95	47,500	**97,500**
Backfill for PCCP pipe (reusing excavated material)	m3	4,752	--	--	--	--	0.04	200	38,016	**38,016**
Bedding for PCCP pipe	m3	1,345	--	--	25	33,625	0.04	200	10,760	**44,385**
Bend for PCCP pipe 24" diam (allocation)	ea	14	--	--	3,000	42,000	20.00	95	26,600	**68,600**
Bend for PCCP pipe 30" & 36" diam (allocation)	ea	14	--	--	5,000	70,000	25.00	95	33,250	**103,250**
Bend for PCCP pipe 72" diam (allocation)	ea	16	--	--	18,000	288,000	40.00	95	60,800	**348,800**
Building architectural (siding, roofing, doors, painting…etc)	ea	2	--	--	250,000	500,000	3,000.00	75	450,000	**950,000**
Butterfly valves 24" c/w allocation for actuator & air lines	ea	4	28,000	112,000	--	--	50.00	106	21,200	**133,200**
Butterfly valves 30" c/w allocation for actuator & air lines	ea	28	30,800	862,400	--	--	50.00	106	148,400	**1,010,800**
Butterfly valves 72" c/w allocation for actuator & air lines	ea	12	96,600	1,159,200	--	--	75.00	106	95,400	**1,254,600**
Butterfly valves 96" c/w allocation for actuator & air lines	ea	10	151,200	1,512,000	--	--	75.00	106	79,500	**1,591,500**
Check valves 24"	ea	4	40,000	160,000	--	--	12.00	106	5,088	**165,088**
Check valves 30"	ea	4	44,000	176,000	--	--	16.00	106	6,784	**182,784**
Check valves 72"	ea	4	138,000	552,000	--	--	32.00	106	13,568	**565,568**
Concrete basin walls (all in)	m3	372	--	--	225	83,700	8.00	75	223,200	**306,900**
Concrete elevated slabs (all in)	m3	646	--	--	250	161,500	10.00	75	484,500	**646,000**
Concrete for transformers and oil catch basin (allocation)	m3	200	--	--	250	50,000	10.00	75	150,000	**200,000**
Concrete slabs on grade (all in)	m3	2,932	--	--	200	586,400	4.00	75	879,600	**1,466,000**
Ductile iron cement pipe 12" diam. for fire water line	ft	1,400	--	--	100	140,000	0.60	95	79,800	**219,800**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Excavation and backfill for fire line & make-up (using excavated material for backfill except for bedding)	m3	9,870	--	--	--	--	0.08	200	157,920	**157,920**
Excavation for PCCP pipe	m3	7,126	--	--	--	--	0.04	200	57,008	**57,008**
Fencing around transformers	m	50	--	--	30	1,500	1.00	75	3,750	**5,250**
Flange for PCCP joints 24"	ea	2	--	--	1,725	3,450	14.00	95	2,660	**6,110**
Flange for PCCP joints 30"	ea	26	--	--	2,260	58,760	16.00	95	39,520	**98,280**
Flange for PCCP joints 72"	ea	8	--	--	9,860	78,880	25.00	95	19,000	**97,880**
Flange for PCCP joints 96"	ea	8	--	--	15,080	120,640	35.00	95	26,600	**147,240**
Foundations for pipe racks and cable racks	m3	190	--	--	250	47,500	8.00	75	114,000	**161,500**
FRP flange 30"	ea	108	--	--	1,679	181,348	50.00	106	572,400	**753,748**
FRP flange 72"	ea	24	--	--	20,888	501,304	200.00	106	508,800	**1,010,104**
FRP flange 96"	ea	12	--	--	40,000	480,000	500.00	106	636,000	**1,116,000**
FRP pipe 72" diam.	ft	240	--	--	851	204,336	1.20	106	30,528	**234,864**
FRP pipe 96" diam.	ft	1,600	--	--	2,838	4,540,800	1.75	106	296,800	**4,837,600**
Harness clamp 24" c/w external testable joint	ea	80	--	--	1,715	137,200	14.00	95	106,400	**243,600**
Harness clamp 30" & 36"c/w internal testable joint	ea	80	--	--	2,000	160,000	16.00	95	121,600	**281,600**
Harness clamp 72" c/w internal testable joint	ea	90	--	--	2,440	219,600	18.00	95	153,900	**373,500**
Joint for FRP pipe 72" diam.	ea	12	--	--	3,122	37,462	200.00	106	254,400	**291,862**
Joint for FRP pipe 96" diam.	ea	50	--	--	17,974	898,700	600.00	106	3,180,000	**4,078,700**
PCCP pipe 24" dia. For blowdown line	ft	1,400	--	--	98	137,200	0.50	95	66,500	**203,700**
PCCP pipe 30" dia. for make-up	ft	1,400	--	--	125	175,000	0.70	95	93,100	**268,100**
PCCP pipe 72" diam.	ft	1,600	--	--	507	811,200	1.30	95	197,600	**1,008,800**
Riser (FRP pipe 30" diam X 55 ft)	ea	24	--	--	15,350	368,400	150.00	106	381,600	**750,000**
Structural steel for building	t	320	--	--	2,500	800,000	20.00	105	672,000	**1,472,000**
CIVIL / STRUCTURAL / PIPING TOTAL	**--**	**--**	**--**	**4,533,600**	**--**	**13,418,505**	**--**	**--**	**12,014,852**	**29,966,957**
ELECTRICAL	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**
4.16 kv cabling feeding MCC's	m	1,000	--	--	75	75,000	0.40	106	42,400	**117,400**
4.16kV switchgear - 4 breakers	ea	1	250,000	250,000	--	--	150.00	106	15,900	**265,900**
460 volt cabling feeding MCC's	m	500	--	--	70	35,000	0.40	106	21,200	**56,200**
480V Switchgear - 1 breaker 3000A	ea	4	30,000	120,000	--	--	80.00	106	33,920	**153,920**
Allocation for automation and control	lot	1	--	--	500,000	500,000	5,000.00	106	530,000	**1,030,000**
Allocation for cable trays	m	800	--	--	75	60,000	1.00	106	84,800	**144,800**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Allocation for lighting and lightning protection	lot	1	--	--	150,000	150,000	1,500.00	106	159,000	**309,000**
Dry Transformer 2MVA xxkV-480V	ea	4	100,000	400,000	--	--	100.00	106	42,400	**442,400**
Lighting & electrical services for pump house building	ea	2	--	--	50,000	100,000	500.00	106	106,000	**206,000**
Local feeder for 200 HP motor 460 V (up to MCC)	ea	24	--	--	18,000	432,000	150.00	106	381,600	**813,600**
Local feeder for 2500 HP motor 4160 V (up to MCC)	ea	4	--	--	45,000	180,000	175.00	106	74,200	**254,200**
Oil Transformer 10/13.33MVA xx-4.16kV	ea	2	190,000	380,000	--	--	150.00	106	31,800	**411,800**
Primary breaker(xxkV)	ea	4	45,000	180,000	--	--	60.00	106	25,440	**205,440**
Primary feed cabling (assumed 13.8 kv)	m	1,000	--	--	175	175,000	0.50	106	53,000	**228,000**
ELECTRICAL TOTAL	**--**	**--**	**--**	**1,330,000**	**--**	**1,707,000**	**--**	**--**	**1,601,660**	**4,638,660**
MECHANICAL	--	--	--	--	--	--	--	--	--	**--**
Allocation for ventilation of buildings	ea	2	100,000	200,000	--	--	1,000.00	106	212,000	**412,000**
Cooling towers for the two combined cycle units	lot	2	6,800,000	13,600,000	--	--	--	--	--	**13,600,000**
Overhead crane 50 ton in (in pump house) Including additional structure to reduce the span	ea	2	500,000	1,000,000	--	--	1,000.00	106	212,000	**1,212,000**
Pump 4160 V 2500 HP	lot	4	1,200,000	4,800,000	--	--	580.00	106	245,920	**5,045,920**
MECHANICAL	**--**	**--**	**--**	**19,600,000**	**--**	**0**	**--**	**--**	**669,920**	**20,269,920**

Appendix C. Net Present Cost Calculation

Project year	Capital / start-up ($)	O&M ($)	Total ($)	Annual discount factor	Present value ($)
0	94,012,500	--	94,012,500	1	**94,012,500**
1	--	792,000	792,000	0.9346	**740,203**
2	--	807,840	807,840	0.8734	**705,567**
3	--	823,997	823,997	0.8163	**672,629**
4	--	840,477	840,477	0.7629	**641,200**
5	--	857,286	857,286	0.713	**611,245**
6	--	874,432	874,432	0.6663	**582,634**
7	--	891,921	891,921	0.6227	**555,399**
8	--	909,759	909,759	0.582	**529,480**
9	--	927,954	927,954	0.5439	**504,714**
10	--	946,513	946,513	0.5083	**481,113**
11	--	965,444	965,444	0.4751	**458,682**
12	--	1,171,368	1,171,368	0.444	**520,087**
13	--	1,194,795	1,194,795	0.415	**495,840**
14	--	1,218,691	1,218,691	0.3878	**472,608**
15	--	1,243,065	1,243,065	0.3624	**450,487**
16	--	1,267,926	1,267,926	0.3387	**429,447**
17	--	1,293,285	1,293,285	0.3166	**409,454**
18	--	1,319,151	1,319,151	0.2959	**390,337**
19	--	1,345,534	1,345,534	0.2765	**372,040**
20	--	1,372,444	1,372,444	0.2584	**354,640**
Total					**104,390,306**

J. MOSS LANDING POWER PLANT

DYNEGY, INC—MOSS LANDING, CA

Contents

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Appendices

1.0 GENERAL SUMMARY

Retrofitting the existing once-through cooling system at Moss Landing Power Plant (MLPP) with closed-cycle wet cooling towers is technically and logistically feasible based on this study's design criteria, and will reduce cooling water withdrawals from Moss Landing Harbor by approximately 95 percent. Impingement and entrainment impacts would be reduced by a similar proportion.

The preferred option selected for MLPP includes 4 conventional wet cooling towers (without plume abatement), with individual cells arranged in a back-to-back configuration for the larger Unit 6 & 7 towers; towers for Units 1 & 2 are an inline arrangement. The Moss Landing Power Plant Modernization Project, completed in 2002, added two new combined-cycle units to the facility. These units were designed to use once-through cooling and use the existing intake structure previously used by Units 1-5, now retired. The new units are referred to as Unit 1 and Unit 2.

Construction-related shutdowns are estimated to take approximately 4 weeks per unit (concurrent). MLPP would likely incur a financial loss as a result of this shutdown, based on 2006 capacity utilization rates, for Units 1 & 2 only.

The cooling tower configuration designed under the preferred option complies with all identified local use restrictions and includes necessary mitigation measures, where applicable.

1.1 COST

Because Units 1 and 2 are substantially newer than the other generating units at MLPP and are likely to operate at a higher utilization rate, it is conceivable that a wet cooling system retrofit would be applied to Unit 1 and Unit 2 only instead of all four active units. Accordingly, some aspects of the cost analysis are presented for the facility as a whole and for Units 1 and Unit 2 alone, i.e., as though they operated as an independent facility. Initial capital and 20-year Net Present Cost (NPC_{20}) costs associated with the installation and operation of wet cooling towers at MLPP are summarized in Table J–1. Annualized costs based on 20-year average values for the various cost elements are summarized in Table J–2.

Table J–1. Cumulative Cost Summary

MLPP (all units)			
Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Total capital and start-up[a]	268,600,000	12.34	42
NPC_{20}[b]	349,600,000	16.07	55

MLPP (Units 1 & 2)			
Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Total capital and start-up[a]	74,700,000	7.90	14
NPC_{20}[b]	122,600,000	12.96	23

[a] Includes all costs associated with the construction and installation of cooling towers and shutdown loss, if any.
[b] NPC_{20} includes all capital costs, operation and maintenance costs, and energy penalty costs over 20 years discounted at 7 percent.

Table J–2. Annual Cost Summary

MLPP (all units)			
Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Capital and start-up [a]	25,400,000	1.17	3.97
Operations and maintenance	2,600,000	0.12	0.41
Energy penalty	5,800,000	0.27	0.91
Total MLPP annual cost	**33,800,000**	**1.56**	**5.29**

MLPP (Units 1 & 2)			
Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Capital and start-up [a]	7,100,000	0.75	1.32
Operations and maintenance	800,000	0.08	0.15
Energy penalty	4,000,000	0.42	0.75
Units 1 & 2 only annual cost	**11,900,000**	**1.25**	**2.22**

[a] Does not include revenue loss associated with shutdown, which is incurred in Year 0 only. Shutdown loss forecast for MLPP equals $5 million. Shutdown cost is associated with Unit 1 and Unit 2 only.

1.2 ENVIRONMENTAL

Environmental changes associated with a cooling tower retrofit for MLPP are summarized in Table J–3 and discussed further in Section 3.4.

Table J–3. Environmental Summary

		Units 1 & 2	Units 6 & 7
Water use	Design intake volume (gpm)	214,000	596,000
	Cooling tower makeup water (gpm)	10,400	28,200
	Reduction from capacity (%)	95	95
Energy efficiency [a]	Summer heat rate increase (%)	0.55	1.22
	Summer energy penalty (%)	1.05	1.99
	Annual heat rate increase (%)	0.57	1.22
	Annual energy penalty (%)	1.06	1.99
Direct air emissions [b]	PM_{10} emissions (tons/yr) (maximum capacity)	123	343
	PM_{10} emissions (tons/yr) (2006 capacity utilization)	70	29

[a] Reflects the comparative increase between once-through and wet cooling systems, but does not account for any operational changes to address the change in efficiency, such as increased fuel consumption (see Section 4.6).
[b] Reflects emissions from the cooling tower only; does not include any increase in stack emissions.

1.3 OTHER POTENTIAL FACTORS

Considerations outside this study's scope may limit the practicality or overall feasibility of a wet cooling tower retrofit at Moss Landing.

Depending on capacity utilization, cooling tower PM_{10} air emissions could result in a significant increase in the facility's total emission profile and may conflict with Monterey Bay Unified Air Pollution Control District air permit regulations, thereby requiring emission offsets or credits. If available, emission credits could add substantial cost to the overall total, if these credits are available in sufficient quantity.

In its approval of the Moss Landing Power Plant Project in 2000, the Energy Resources and Development Commission noted concerns over increased PM_{10} emissions and cited them as one of several reasons why once-through cooling was the preferred option for the repowering project. The Commission also noted that wet cooling towers were not preferred because entrainment impacts could be effectively mitigated, in part through habitat restoration and enhancement programs (ERDC 2000). It is unclear how this decision would be affected by the Second Circuit decision prohibiting the use of restoration as an impingement and entrainment compliance option (see Chapter 2).

PM_{10} emission credit availability and cost data were not available for this study and are not included in the final cost evaluation.

2.0 BACKGROUND

MLPP is a natural gas-fired steam electric generating facility located in Monterey County, owned and operated by Dynegy, Inc. The facility site occupies part of a 380-acre industrial site near Moss Landing Harbor along the Monterey Bay coast, approximately half way between Santa Cruz and Monterey. The northern portion of the facility is bordered by Elkhorn Slough. California Highway 1 borders the property's western edge (Figure J–1). MLPP currently operates two conventional steam generating units (Units 6 and 7), and two combined-cycle units (Units 1 and 2), each consisting of two gas combustion turbines, one heat recovery steam generator (HRSG), and one steam turbine. Five other steam units were retired in 1995. (See Table J–4 and Figure J–1.)

Table J–4. General Information

Unit	In-service year	Rated capacity (MW)	2006 capacity utilization [a]	Condenser cooling water flow (gpm)
1	2002	540	56.7%	107,000
2	2002	540	56.6%	107,000
6	1967	702	6.2%	298,000
7	1968	702	10.8%	298,000
MLPP total		**2484**	**29.4%**	**810,000**

[a] Quarterly Fuel and Energy Report—2006 (CEC 2006).

Figure J–1. General Vicinity of Moss Landing Power Plant

2.1 COOLING WATER SYSTEM

MLPP operates two separate cooling water intake structures (CWISs) to provide condenser cooling water the generating units. The CWIS for Unit 1 and Unit 2 uses the intake previously used by the retired units (Figure J–2). A separate structure serves Unit 6 and Unit 7. Once-through cooling water is combined with low volume wastes generated by MLPP and discharged through a submerged outfall extending 600 feet into Monterey Bay. Surface water withdrawals and discharges are regulated by NPDES Permit CA0006254 as implemented by Central Coast Regional Water Quality Control Board (CCRWQCB) Order 00-041.

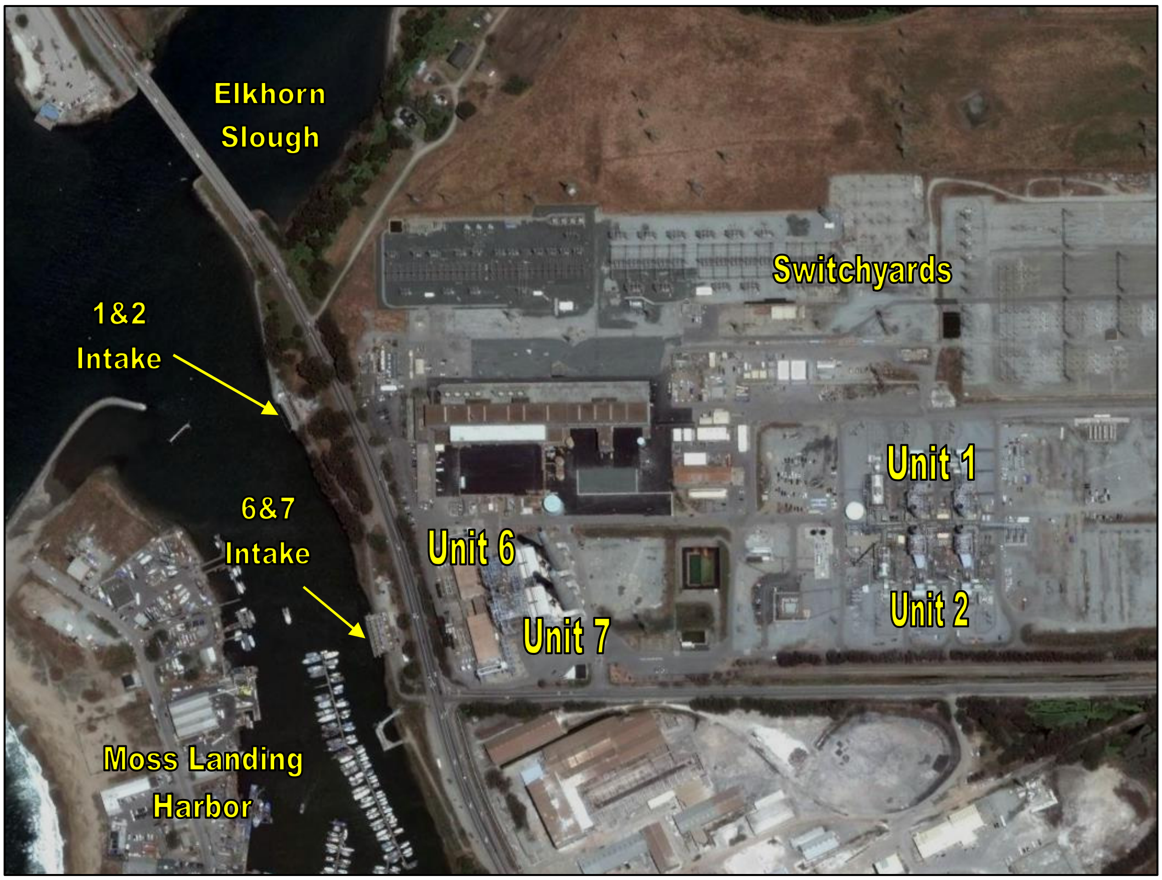

Figure J–2. Site View

The CWIS for Units 1 and 2 is a surface structure located flush with the shoreline along the eastern edge of Moss Landing Harbor. This intake was modified from its original design when it was used for the retired units. Cooling water for Unit 6 and Unit 7 is withdrawn from the harbor through a similar structure approximately 750 feet south of the other intake.

The Unit 1 and 2 CWIS consists of vertical inclined traveling screens fitted with 5/16-inch woven wire mesh panels. The screens are inclined approximately 55 degrees from horizontal to aid in the removal of eelgrass that can accumulate on the screen panels. Screens are rotated periodically at

24-hour intervals or based on pressure differential between the upstream and downstream faces of the screen. A high pressure spray removes any debris or fish that have become impinged on the screen face. Downstream of the screens are six circulating water pumps, three for each unit, that draw water from the wet well to the surface condensers. The pumps for Units 1 and 2 are each rated at 42,000 gallons per minute (gpm), or 60 million gallons per day (mgd) (MLPP 2000).

The Unit 6 and 7 CWIS is essentially the same as the Unit 1 and 2 CWIS except the traveling screens are vertical in the water column and fitted with 3/8-inch mesh panels. Downstream of the screens are four circulating water pumps, two for each unit, that draw water from the wet well to the surface condensers. The pumps for Units 6 and 7 are each rated at 150,000 gpm, or 216 mgd.

At maximum capacity, MLPP maintains a total pumping capacity rated at 1,224 mgd.

2.2 SECTION 316(B) PERMIT COMPLIANCE

As part of the MLPP Modernization Project that added the combined-cycle units in 2002, the CWIS that was used for the retired unites was modified to service Units 1 and 2. The original design placed the intake screens at the end of a 350-foot tunnel extending from Moss Landing Harbor under the Pacific Coast Highway to the facility. The length of the tunnel and lack of light are believed to have contributed to the impingement of fish that could not escape back to the harbor. The updated design moved the intake screens closer to the harbor shoreline and they are now recessed approximately 10 feet. This study did not evaluate the effectiveness of this modification.

Apart from the modifications to the Unit 1 and 2 CWIS, MLPP does not use technologies generally considered to be effective at reducing impingement mortality and/or entrainment.

MLPP's previous owner (Pacific Gas and Electric [PG&E]) conducted studies to demonstrate compliance with CWA Section 316(b) requirements in 1983 (supplemental reports were submitted in 1986 and 1988) and formed the basis for NPDES permitting requirements related to the cooling water withdrawals from Moss Landing Harbor for the facility as it was then configured. CCRWQCB Order 00-041, adopted in 2000, states the following:

> …[t]he reports determined that impacts could be minimized through operation and maintenance procedures. Based on these reports the Regional Board determined that the existing intake system operation complied with the BTA requirements of section 316(b). Report conclusions were re-evaluated as part of the review process for this permit and it was determined that there is no basis for reconsidering the Board's existing determination of compliance regarding the existing intake system operation. (CCRWQCB 2000, Finding 45)

In the discussion of modifications to the Unit 1 and 2 CWIS, Order 00-041 notes that "these modifications are not sufficient to minimize adverse environmental effects of the intake system and to achieve compliance with the BTA requirements of section 316(b) because the modifications do not address entrainment impacts" (CCRWQCB 2000, Finding 49).

MLPP and the California Energy Commission (CEC), as part of the certification process for the modernization project, developed the Elkhorn Slough Enhancement Program (ESEP) to protect aquatic resources in the watershed. The program requires MLPP to fund activities that "mitigate significant effects of larvae entrainment by the cooling water intake system by using the most direct means to increase the biological health and productivity of Elkhorn Slough watershed" (CCRWQCB 2000, Finding 50). These activities included acquisition of sensitive riparian areas and habitat restoration projects in nearby wetlands and upland areas.

Order 00-041 states that the combination of CWIS modifications for Units 1 and 2 and ESEP funding and implementation "constitutes compliance with Clean Water Act section 316(b) by implementing BTA that minimizes adverse environmental effects" (CCRWQCB 2000, Finding 51). In light of the Second Circuit's Phase II determination that restoration or mitigation projects may not be used as an option for Section 316(b) compliance, it is not clear how the ESEP program will be affected or how the CCRWQCB may modify future NPDES permits for MLPP.

3.0 WET COOLING SYSTEM RETROFIT

3.1 OVERVIEW

This study evaluates saltwater cooling towers as a retrofit option at MLPP, with the current source water (Moss Landing Harbor) continuing to provide makeup water to the facility. Converting the existing once-through cooling system to wet cooling towers will reduce the facility's current intake capacity by approximately 95 percent; rates of impingement and entrainment will decline by a similar proportion. Use of reclaimed water was considered for MLPP but not analyzed in detail because the available volume cannot serve as a replacement for once-through cooling water. Reclaimed water may be an attractive alternative as a makeup water source for a wet cooling tower when considering the additional benefits its use may provide. The availability of reclaimed water in the area surrounding MLPP is limited, however, and may not be sufficient to supply the makeup requirement for Units 1 and 2, let alone all four units.

The wet cooling towers' configuration—their size, arrangement, and location—was based on best professional judgment (BPJ) using the criteria outlined in Chapter 5 and designed to meet the performance benchmarks in the most cost-effective manner. Information not available to this study that offers a more complete facility characterization may lead to different conclusions regarding the cooling towers' physical configuration.

This study developed a conceptual design of wet cooling towers sufficient to meet each active generating unit's cooling demand at its rated output during peak climate conditions. Cost estimates are based on vendor quotes developed using the available information and the various design constraints identified at MLPP.

The overall practicality of retrofitting both units at MLPP will require an evaluation of factors outside the scope of this study, such as each unit's age and efficiency and its role in the overall reliability of electricity production and transmission in California, particularly the San Francisco and Central Coast regions.

3.2 DESIGN BASIS

3.2.1 CONDENSER SPECIFICATIONS

For this study, the wet cooling tower conceptual design selected for MLPP is based on the assumption that the condenser flow rate and thermal load to each will remain unchanged from the current system. Although no provision is included to re-optimize the condenser performance for service with a cooling tower, some modifications to the condenser (tube sheet and water box reinforcement) may be necessary to handle the increased water pressures that will result from the increased total pump head required to raise water to the cooling tower riser elevation.[1] The practicality and difficulty of these modifications are dependent each unit's age and configuration but are assumed to be feasible at MLPP. Additional costs for condenser modifications are included in the discussion of capital expenditures (Section 4.3).

[1] In this context, re-optimization refers to a comprehensive condenser overhaul that reduces thermal efficiency losses associated with a wet cooling tower's higher circulating water temperatures. Modifications discussed in this study are generally limited to reinforcement measures that enable the condenser to withstand increased water pressures.

Information provided by MLPP was largely used as the basis for the cooling tower design. In some cases, the data were incomplete or conflicted with values obtained from other sources.

Where possible, questionable values were verified or corrected using other known information about the condenser.

Parameters used in the development of the cooling tower design are summarized in Table J–5.

Table J–5. Condenser Design Specifications

	Units 1 & 2	Units 6 & 7
Thermal load (MMBTU/hr)	1,067.5	2,930
Surface area (ft^2)	96,500	435,000
Condenser flow rate (gpm)	107,000	298,000
Tube material	Titanium	Titanium
Heat transfer coefficient (BTU/hr•ft^2•°F)	563.2	509.5
Cleanliness factor	0.9	0.9
Inlet temperature (°F)	56.1	60
Temperature rise (°F)	19.96	19.67
Steam condensate temperature (°F)	87.3	89.0
Turbine exhaust pressure (in. HgA)	1.305	1.38

3.2.2 AMBIENT ENVIRONMENTAL CONDITIONS

MLPP is located in Monterey County near Moss Landing Harbor on the Monterey Bay coast. Cooling water is withdrawn at the surface from a shoreline intake structure in the harbor. Inlet temperature data were not available from MLPP. Instead, surface water temperatures used in this analysis were based on monthly average coastal water temperatures as reported in the NOAA *Coastal Water Temperature Guide for Santa Cruz, CA* (NOAA 2007).

The wet bulb temperature used in the development of the overall cooling tower design was obtained from American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) publications. Data for Monterey indicate a 1 percent ambient wet bulb temperature of 63° F (ASHRAE 2006). The same value is referenced as the 1 percent design criteria in documents provided by MLPP. An approach temperature of 12° F was selected based on the site configuration and vendor input. At the design wet bulb and approach temperatures, the cooling towers will yield “cold” water at a temperature of 75° F.

Monthly maximum wet bulb temperatures used in the development of energy penalty estimates in Section 4.6 were calculated using data obtained from California Irrigation Management Information System (CIMIS) Monitoring Station 19 in Castroville (CIMIS 2006). Climate data used in this analysis are summarized in Table J–6.

Table J–6. Surface Water and Ambient Wet Bulb Temperatures

	Surface (°F)	Ambient wet bulb (°F)
January	53.0	56.3
February	53.4	57.0
March	55.9	60.0
April	57.7	58.4
May	58.6	61.8
June	59.2	60.0
July	59.4	62.4
August	62.1	63.2
September	60.3	62.0
October	56.8	61.1
November	55.0	61.9
December	53.9	58.8

3.2.3 LOCAL USE RESTRICTIONS

3.2.3.1 NOISE

Industrial development at MLPP is regulated by Title 20 of the Monterey County Zoning Ordinance (Coastal Implementation Plan). The plan outlines narrative criteria to be used when evaluating the potential impacts from noise on surrounding areas. If a finding of significant impact is made, noise abatement measures may be required including relocating or reorienting structures, low noise fans and landscaped setbacks from noise sources. The use of sound walls for noise control is prohibited.

The areas surrounding MLPP are predominately agricultural and industrial, with Moss Landing Harbor the most likely point of impact. Duke Energy, in an evaluation of alternative cooling options for the MLPP modernization project, conducted a detailed analysis of potential noise levels from mechanical draft wet cooling towers at various locations surrounding the site. That analysis determined that noise associated with wet cooling tower operation was insignificant and would not require additional noise abatement measures (Duke 2000). Accordingly, this study did not include any noise control measures in the cooling tower design.

3.2.3.2 BUILDING HEIGHT

The developed portion of MLPP is located within the heavy industry (HI) zone according to Coastal Implementation Plan. This zone is dedicated to coastal-dependent industrial uses and limits structural height to 35 feet. Exceptions to this limitation are made on a conditional use basis that evaluates the existing character of the site and the surrounding areas. Based on consultation with the Monterey County Planning Department, MLPP, as an industrial site would be eligible for a conditional use exception. This study selected a height restriction of 60 feet above grade level. The height of the wet cooling towers designed for MLPP Units 1 and 2, from grade level to the top of the fan deck, is 44 feet. The height of the Unit 6 and 7 towers is 55 feet.

3.2.3.3 PLUME ABATEMENT

Local zoning ordinances do not contain any specific criteria for addressing impacts associated with a wet cooling tower plume. Using the selection criteria for this study, plume abatement measures were not considered for MLPP; all towers are a conventional design. The plume from wet cooling towers at MLPP is not expected to adversely impact nearby infrastructure.

Community standards for assessing the visual impact associated with a cooling tower plume cannot be determined within the scope of this study. The proximity of nearby recreational areas (Moss Landing State Beach), when viewed in the context of CEC siting guidelines, may contribute to the selection of an alternate design if a wet cooling tower retrofit is undertaken at MLPP in the future. These guidelines assess the total size and persistence of a visible plume with respect to impacts on the viewshed from surrounding areas.

3.2.3.4 DRIFT AND PARTICULATE EMISSIONS

Drift elimination measures that are considered best available control technology (BACT) are required for all cooling towers evaluated in this study, regardless of their location. State-of-the-art drift eliminators are included for each cooling tower cell at MLPP, with an accepted efficiency of 0.0005 percent. Because cooling tower PM_{10} emissions are a function of the drift rate, drift eliminators are also considered BACT for PM_{10} emissions from wet cooling towers. This efficiency can be verified by a proper in situ test, which accounts for site-specific climate, water, and operating conditions. Testing based on the Cooling Tower Institute's Isokinetic Drift Test Code is required at initial start-up on only one representative cell of each tower for an approximate cost of $60,000 per test, or approximately $240,000 for all four cooling towers at MLPP (CTI 1994). This cost is not itemized in the final analysis and is instead included as part of the indirect cost estimate (Section 4.3).

3.2.3.5 FACILITY CONFIGURATION AND AREA CONSTRAINTS

The existing site's configuration does not present significant challenges to identifying a location for conventional cooling towers, although the selected location results in long distances between the Unit 6 and 7 cooling towers and the generating units. As shown in Figure J–3, the property's total area is relatively large and can accommodate mechanical draft wet cooling towers.

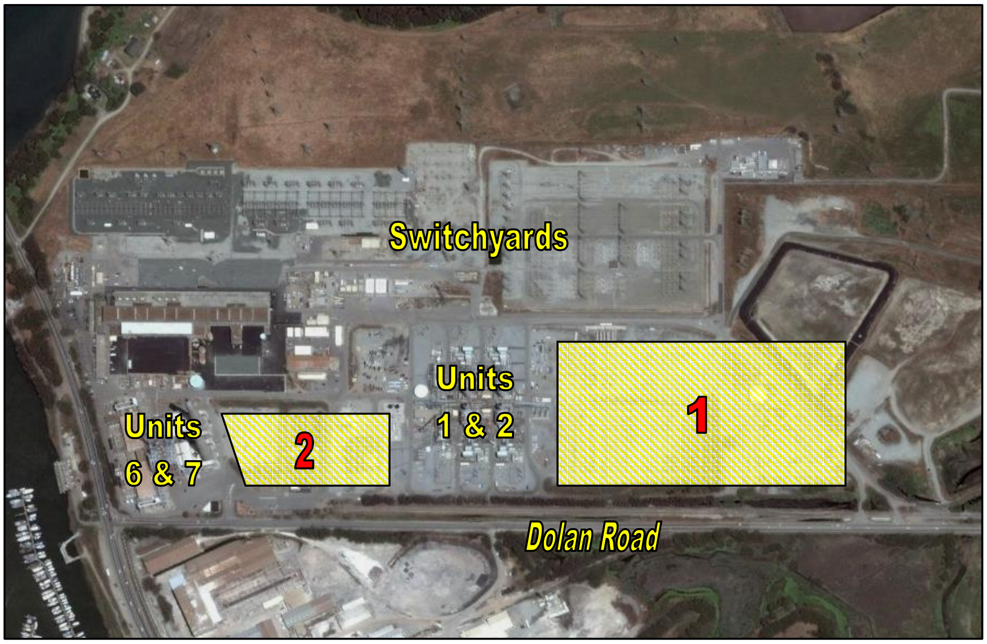

Figure J–3. Cooling Tower Siting Locations

Area 1 is generally unoccupied with a total area of approximately 30 acres. This area extends approximately 1,600 feet alongside Dolan Road heading east from Moss Landing Harbor.

Area 2 is smaller but located much closer to Units 6 and 7. The towers designed for Units 6 and 7, approximately 700 feet long by 100 feet wide, would consume most of the available space in this area and may not be configured in an ideal arrangement. In addition, the area is partially occupied by three hazardous waste surface impoundments that are permitted by a separate order (R3-2004-104). Use of Area 2 would require relocation or removal of these ponds, but their status is unknown to this study. The level of remediation required, if any, cannot be determined. Area 2, therefore, was not considered further. Towers for all four units are placed in Area 1.

3.3 CONCEPTUAL DESIGN

Based on the design constraints discussed above, four wet cooling towers were selected to replace the current once-through cooling system that serves the four generating units at MLPP. Each unit will be served by an independently-functioning tower with separate pump houses and pumps. The towers for Units 1 and 2 consist of conventional cells arranged in a multi-cell, inline configuration. The towers for Units 6 and 7 are similar but arranged in a back-to-back configuration.

3.3.1 SIZE

Each tower is constructed over a concrete collection basin 4 feet deep. The basin is larger than the tower structure's footprint, extending an additional 2 feet in each direction. The concrete used for construction is suitable for saltwater applications. The principal tower material is fiberglass reinforced plastic (FRP), with stainless steel fittings. These materials are more resistant to the higher corrosive effects of saltwater.

The size of each tower is primarily based on the thermal load rejected to the tower by the surface condenser and a 12° F approach to the ambient wet bulb temperature. Flow rates through each condenser remain unchanged.

General characteristics of the wet cooling towers selected for MLPP are summarized in Table J–7.

Table J–7. Wet Cooling Tower Design

	Tower Complex 1 (Units 1 & 2)	Tower Complex 2 (Units 6 & 7)
Thermal load (MMBTU/hr)	2,135	5,860
Circulating flow (gpm)	214,000	596,000
Number of cells	20	52
Tower type	Mechanical draft	Mechanical draft
Flow orientation	Counterflow	Counterflow
Fill type	Modular splash	Modular splash
Arrangement	Inline	Back-to-back
Primary tower material	FRP	FRP
Tower dimensions (l x w x h) (ft)	480 x 54 x 44	720 x 96 x 55
Tower footprint with basin (l x w) (ft)	484 x 58	724 x 100

3.3.2 LOCATION

The initial site selection for each tower was based on the desire to locate each tower as close as possible to the respective generating units to minimize the supply and return pipe distances and any increases in total pump head and brake horsepower. At MLPP, the linear distance between Units 6 and 7 and Tower Complex 2 is large (approximately 1,500 feet) but does not present any significant challenges for placing the supply and return pipelines (Figure J–4). This area was also evaluated by Duke Energy, which selected this location "to place the cooling towers downwind of the main equipment areas. This downwind location avoids potential damage from concentrated sea water drift droplets from the cooling tower plumes" (Duke 2000).

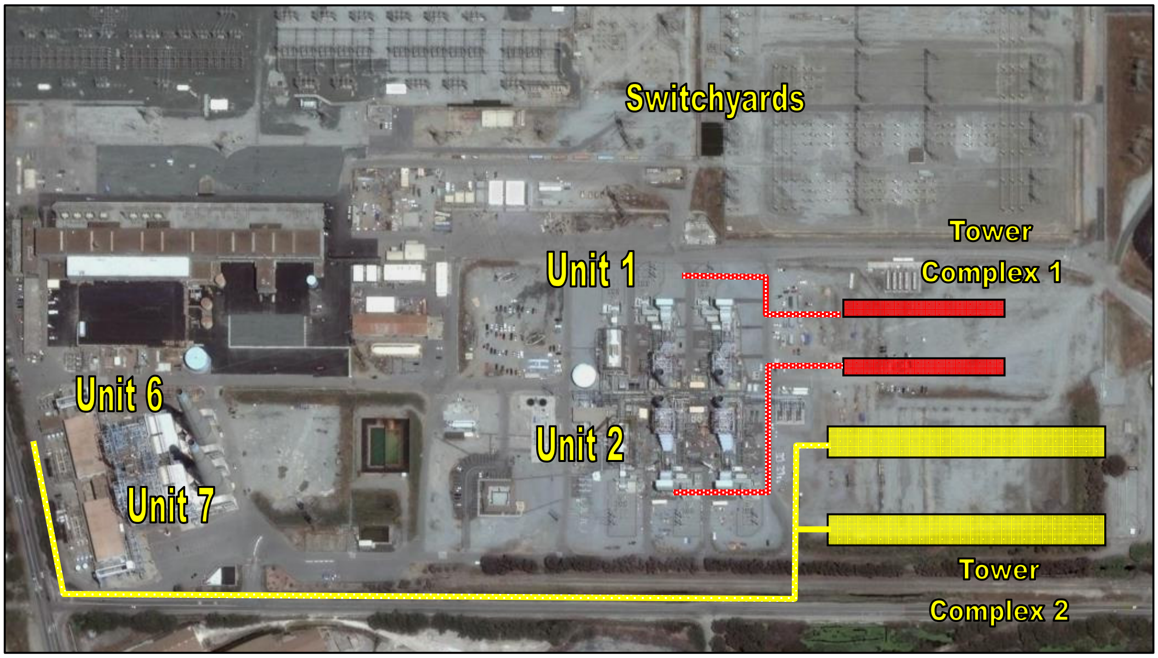

Figure J–4. Cooling Tower Locations

3.3.3 PIPING

The proximity of Tower Complex 1 to Units 1 and 2 allows for most of the supply and return piping (FRP) to be placed above ground on pipe racks. Small sections near the towers will be placed underground and made of prestressed concrete cylinder pipe (PCCP).

The main supply and return pipelines to and from Tower Complex 2 will be located underground and made PCCP suitable for saltwater applications. These pipes range in size from 72 to 120 inches in diameter. The distance between Tower Complex 2 and Units 6 and 7 requires 8,000 feet of PCCP for the supply and return lines. Pipes connecting the condensers to the supply and return lines are made of FRP and placed above ground on pipe racks. Above ground placement avoids the potential disruption that may be caused by excavation in and around the power block. The condensers at MLPP are all located at grade level, enabling a relatively straightforward connection.

All riser piping (extending from the foot of the tower to the level of water distribution) is constructed of FRP.

Potential interference with underground obstacles and infrastructure is a concern, particularly at existing sites that are several decades old and have been substantially modified or rebuilt in the interim. Avoidance of these obstacles is considered to the degree practical in this study. Associated costs are included in the contingency estimate and are generally higher than similar estimates for new facilities (Section 4.3).

Appendix B details the total quantity of each pipe size and type for MLPP.

3.3.4 FANS AND PUMPS

Each tower cell uses an independent single-speed fan. The fan size and motor power are the same for each cell in all four towers.

This analysis includes new pumps to circulate water between the condensers and cooling towers. Pumps are sized according to the flow rate for each tower, the relative distance between the towers and condensers, and the total head required to deliver water to the top of each cooling tower riser. A separate, multilevel pump house is constructed for each tower and sized to accommodate the motor control centers (MCCs) and appropriate electrical switchgear. The electrical installation includes all necessary transformers, cabling, cable trays, lighting, and lightning protection. A 30-ton overhead crane is also included to allow for pump servicing.

Fan and pump characteristics associated with wet cooling towers at MLPP are summarized in Table J–8. The net electrical demand of fans and new pumps is discussed further as part of the energy penalty analysis in Section 4.6.

Table J–8. Cooling Tower Fans and Pumps

		Tower Complex 1 (Units 1 & 2)	Tower Complex 2 (Units 6 & 7)
Fans	Number	20	52
	Type	Single speed	Single speed
	Efficiency	0.95	0.95
	Motor power (hp)	211	211
Pumps	Number	6	4
	Type	50 % recirculating Mixed flow Suspended bowl Vertical	50 % recirculating Mixed flow Suspended bowl Vertical
	Efficiency	0.88	0.88
	Motor power (hp)	932	3,636

3.4 ENVIRONMENTAL EFFECTS

Converting the existing once-through cooling system at MLPP to wet cooling towers will significantly reduce the intake of seawater from Moss Landing Harbor and will presumably reduce impingement and entrainment by a similar proportion. Because closed-cycle systems will almost always result in condenser cooling water temperatures higher than those found in a comparable once-through system, wet towers will increase the operating heat rates at all four of MLPP's steam units, thereby decreasing the facility's overall efficiency. Additional power will also be consumed by the tower fans and circulating pumps.

Depending on how MLPP chooses to address this change in efficiency, total stack emissions may increase for pollutants such as PM_{10}, SO_x, and NO_x, and may require additional control measures (e.g., electrostatic precipitation, flue gas desulfurization, and selective catalytic reduction) or the purchase of emission reduction credits (ERCs) to meet air quality regulations. The availability of ERCs and their associated cost was not evaluated as part of this study.

No control measures are currently available for CO_2 emissions, which will increase, on a per-kWh basis, by the same proportion as any change in the heat rate. The towers themselves will constitute an additional source of PM_{10} emissions, the annual mass of which will largely depend on the capacity utilization rate for the generating units served by each tower.

If MLPP retains its NPDES permit to discharge wastewater to the Pacific Ocean with a wet cooling tower system, it may have to address revised effluent limitations resulting from the substantial change in the discharge quantity and characteristics. Thermal impacts from the current once-through system, if any, will be minimized with a wet cooling system.

3.4.1 AIR EMISSIONS

MLPP is located in the North Central Coast air basin. Air emissions are permitted by the Monterey Bay Unified Air Pollution Control District (MBUAPCD) (Facility ID A0012).

Drift volumes are expected to be within the range of 0.5 gallons for every 100,000 gallons of circulating water in the towers. At MLPP, this corresponds to a rate of approximately 4 gpm based on the maximum combined flow in all four towers. Because the area selected for wet cooling towers is located at a substantial distance from sensitive structures, salt drift deposition is not likely to be a significant concern.

Total PM_{10} emissions from the MLPP cooling towers are a function of the number of hours in operation, overall water quality in the tower, and evaporation rate of drift droplets prior to deposition on the ground. Makeup water at MLPP will be obtained from the same source currently used for once-through cooling water (Moss Landing Harbor). At 1.5 cycles of concentration and assuming an initial TDS value of 35 parts per thousand (ppt), the water within the cooling towers will reach a maximum TDS level of roughly 53 ppt. Any drift droplets exiting the tower will have the same TDS concentration.

The cumulative mass emission of PM_{10} from MLPP will increase as a result of the direct emissions from the cooling towers themselves. Stack emissions of PM_{10}, as well as SO_x, NO_x, and other pollutants, will increase due to the drop in fuel efficiency, although the cumulative increase will depend on actual operations and emission control technologies currently in use. Maximum drift and PM_{10} emissions from the cooling towers are summarized in Table J–9.[2]

Data summarizing the total facility emissions for these pollutants in 2005 are presented in Table J–10 (CARB 2005). In 2005, MLPP operated at an annual capacity utilization rate of 28 percent.

[2] This is a conservative estimate that assumes all dissolved solids present in drift droplets will be converted to PM_{10}. Studies suggest this may overestimate actual emission profiles for saltwater cooling towers (Chapter 4).

Using this rate, the additional PM_{10} emissions from the cooling towers would increase the facility total by approximately 130 tons/year, or 154 percent.[3]

Table J–9. Full Load Drift and Particulate Estimates

	PM_{10} (lbs/hr)	PM_{10} (tons/year)	Drift (gpm)	Drift (lbs/hr)
Tower Complex 1	28	123	1.1	535
Tower Complex 2	78	343	3.0	1,491
Total MLPP PM_{10} and drift emissions	**106**	**466**	**4.1**	**2,026**

Table J–10. 2005 Emissions of SO_x, NO_x, PM_{10}

Pollutant	Tons/year
NO_x	141
SO_x	9
PM_{10}	85

3.4.2 MAKEUP WATER

The volume of makeup water required by both cooling towers at MLPP is the sum of evaporative loss and the blowdown volume required to maintain the circulating water in each tower at the design TDS concentration. Drift expelled from the towers represents an insignificant volume by comparison and is accounted for by rounding up evaporative loss estimates. Makeup water volumes are based on design conditions, and may fluctuate seasonally depending on climate conditions and facility operations. Wet cooling towers will reduce once-through cooling water withdrawals from Moss Landing Harbor by approximately 95 percent over the current design intake capacity.

Table J–11. Makeup Water Demand

	Tower circulating flow (gpm)	Evaporation (gpm)	Blowdown (gpm)	Total makeup water (gpm)
Tower Complex 1	214,000	3,400	6,800	10,200
Tower Complex 2	596,000	9,400	18,800	28,200
Total MLPP makeup water demand	**810,000**	**12,800**	**25,600**	**38,400**

One circulating water pump, rated at 42,00 gpm, which is currently used to provide once-through cooling water to the facility, will be retained in a wet cooling system to provide makeup water to each cooling tower. The retained pump's capacity exceeds the makeup demand by approximately 3,000 gpm. Any excess capacity will be routed through a bypass conduit and returned to the wet well at a point located behind the intake screens. Recirculating the excess capacity in this manner reduces additional cost that would be incurred if new pumps were required while maintaining the desired flow reduction. The intake of new water, measured at the intake screens, will be equal to the cooling towers' makeup water demand. Figure J–5 presents a schematic of this configuration.

[3] 2006 emission data are not currently available from the Air Resources Board website. For consistency, the comparative increase in PM10 emissions estimated here is based on the 2005 MLPP capacity utilization rate instead of the 2006 rate presented in Table J-4. All other calculations in this chapter use the 2006 value.

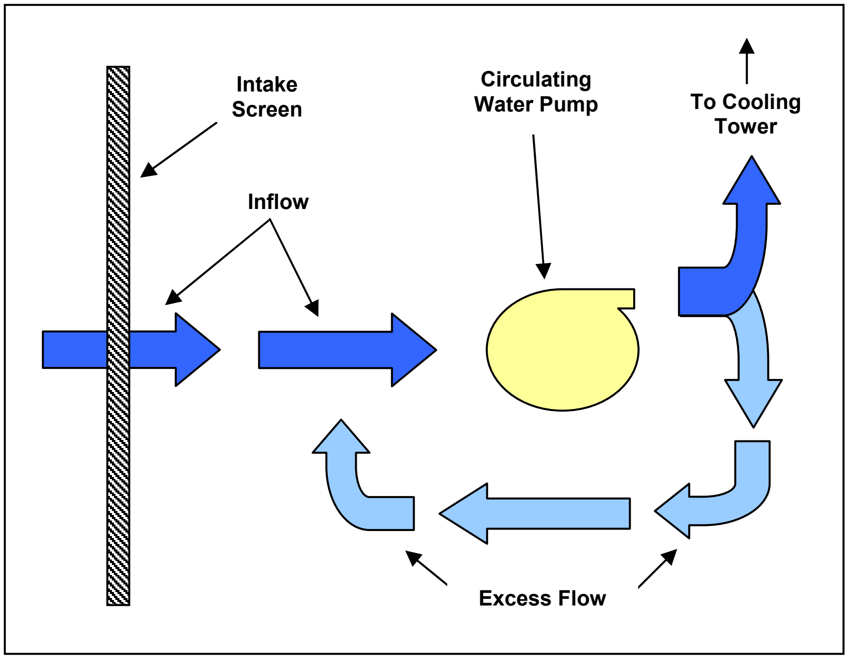

Figure J–5. Schematic of Intake Pump Configuration

The existing once-through cooling system at MLPP does not treat water withdrawn from Moss Landing Harbor with the with the exception of screening for debris and larger organisms and periodic chlorination to control biofouling in the condenser tubes. Heat treatments are also periodically used to control mussel growth on pipes and condenser tubes by raising the circulating water temperature. Conversion to a wet cooling tower system will not interfere with chlorination or heat treatment operations.

Makeup water will continue to be withdrawn from Moss Landing Harbor.

The wet cooling tower system proposed for MLPP includes water treatment for standard operational measures, i.e., corrosion inhibitors, biocides, and anti-scaling agents. An allowance for these additional chemical treatments is included in annual O&M costs. It is assumed that the current once-through cooling water quality will be acceptable for use in a seawater cooling tower (with continued screening and chlorination) and will not require any pretreatment to enable its use.

3.4.3 NPDES PERMIT COMPLIANCE

At maximum operation, wet cooling towers at MLPP will result in an effluent discharge of approximately 37 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, floor drain wastes, and cleaning wastes. These low volume wastes may add an additional 1.0 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, MLPP will be required to modify its existing individual wastewater discharge (NPDES) permit.

Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0006254 as implemented by CCRWQCB Order 00-041. All once-through cooling water and process wastewaters are discharged through a submerged outfall extending offshore into the Pacific Ocean. The existing Order contains effluent limitations based on the 1997 Ocean Plan and the 1972 Thermal Plan.

MLPP will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities (40 CFR 423.13(d)(1)). These ELGs set numeric limitations for chromium and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity). Because ELGs are technology-based limitations, mixing zones or dilution factors are not applicable when determining compliance; limits must be met at the point of discharge from the cooling tower prior to commingling with any other waste stream. ELGs for cooling tower blowdown target priority pollutants that are contributed by maintenance chemicals and do not apply when limits may be exceeded as a result of background concentrations or other sources. Further discussion can be found in Chapter 4, Section 3.6.

Conversion to wet cooling towers will alter the volume and composition of a facility's wastewater discharge because wet towers concentrate certain pollutants in the effluent waste stream. The cooling towers designed for MLPP operate at 1.5 cycles of concentration, i.e., the blowdown discharge will contain a dissolved solids concentration 50 percent higher than the makeup water.

Changes to discharge composition may affect compliance with water quality objectives included in the Ocean Plan. If compliance with these objectives becomes problematic, alternative treatment or discharge methods may be necessary. Compliance may be achieved by altering the discharge configuration in such a way as to increase dilution (e.g., diffuser ports), or by seeking a mixing zone and dilution credits as permissible under the Ocean Plan. Alternately, some low volume waste streams (e.g., boiler blowdown, laboratory drains) may be diverted, with necessary permits, for treatment at a POTW.

If more pollutant-specific treatment methods, such as filtration or precipitation technologies, become necessary to meet WQBELs, the initial capital cost may range from $2 to $5.50 per 1,000 gallons of treatment capacity, with annual costs of approximately $0.5 per gallon of capacity, depending on the method of treatment (FRTR 2002). Hazardous material disposal fees and permits would further increase costs.

This evaluation did not include alternative discharge or effluent treatment measures in the conceptual design because the variables used to determine final WQBELs, which would be used to determine the type and scope of the desired compliance method, cannot be quantified here. Likewise, the final cost evaluation (Section 4.0) does not include any allowance for these possibilities.

Thermal discharge standards are based on narrative criteria established for discharges to coastal waters under the Thermal Plan, which requires that existing discharges of elevated-temperature wastes comply with effluent limitations necessary to assure the protection of designated beneficial uses. The CCRWQCB has implemented this provision by establishing a maximum discharge temperature of no more than 26º F to 34º F in excess of the temperature of the receiving water during normal operations, depending on which units are operating (CCRWQCB 2000).

3.4.4 RECLAIMED WATER

Reclaimed or alternative water sources used in conjunction with wet cooling towers could eliminate all surface water withdrawals at MLPP. Doing so would completely eliminate impingement and entrainment concerns, and might enable the facility to avoid possible effluent quality and permit compliance issues, depending on the quality of reclaimed water available for use. In addition, wet cooling towers using reclaimed water would be expected to have lower PM_{10} emissions due to the lower TDS levels. The California State Water Resources Control Board (SWRCB), in 1975, issued a policy statement requiring the consideration of alternative cooling methods in new power plants, including reclaimed water, over the use of freshwater (SWRCB 1975). There is no similar policy regarding marine waters, but the clear preference of state agencies is to encourage alternative cooling methods, including reclaimed water, wherever possible.

The present volume of available reclaimed water within a 15-mile radius of MLPP (5 mgd) does not meet the current once-through cooling demand and can potentially meet the makeup water demand only for Units 1 and 2. This study did not pursue a detailed investigation of reclaimed water's use because the conversion of MLPP's once-through cooling system to saltwater cooling towers meets the performance benchmarks for impingement and entrainment impact reductions discussed in the 2006 California Ocean Protection Council (OPC) Resolution on Once-Through Cooling Water (see Chapter 1).

To be acceptable for use as makeup water in cooling towers, reclaimed water must meet tertiary treatment and disinfection standards under California Code of Regulations (CCR) Title 22. If the reclaimed water is not treated to the required levels, MLPP would be required to arrange for sufficient treatment, either onsite or at the source facility, prior to its use in the cooling towers.

Two publicly owned treatment works (POTWs) were identified within a 15-mile radius of MLPP, with a combined discharge capacity of 40 mgd. The available portion of this volume varies by season. A significant portion of the effluent in the region is treated to either advanced secondary or tertiary standards and recycled for irrigation on many nearby agricultural operations. Figure J–6 shows the relative locations of these facilities to MLPP.

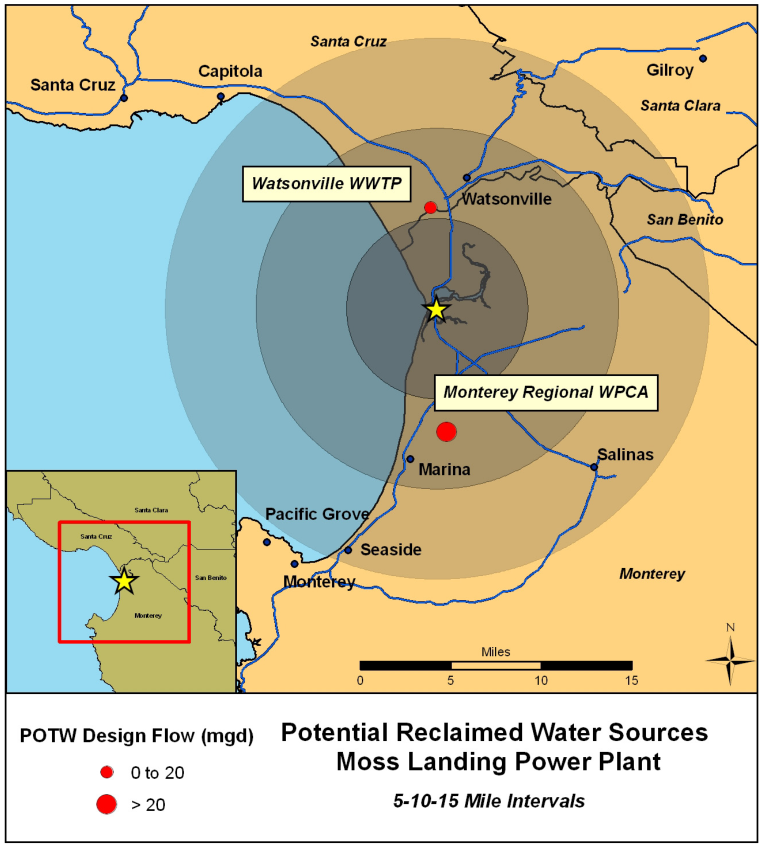

Figure J-6. Reclaimed Water Sources

- *Watsonville Wastewater Treatment Plant—Watsonville*
  Discharge volume: 10 mgd
  Distance: 6 miles N
  Treatment level: Advanced secondary

  All water is treated to advanced secondary standards and discharged to Monterey Bay through a submerged outfall. The Pajaro Valley Water Management Agency is in the process of upgrading the Watsonville WWTP to provide tertiary treatment for approximately 3.5 mgd for use as irrigation water at local agricultural operations during the spring, summer and fall (expected completion 2008). The remaining capacity—approximately 5 to 6 mgd—is sufficient to provide all of the makeup water required for the Unit 1 and 2 cooling towers (4 to 6 mgd). Additional volume would be available during winter months.

- *Monterey Regional Water Pollution Control Agency (MRWPCA)—Marina*
  Discharge volume: 29.6 mgd
  Distance: 7 miles S
  Treatment level: Tertiary

  MRWPCA currently treats the design capacity of 29.6 mgd to tertiary standards for use as irrigation water on approximately 12,000 acres of regional agricultural operations. Any portion not recycled for irrigation is discharged through a submerged outfall to Monterey Bay. The demand for reclaimed water varies seasonally with more water available during winter months. No reclaimed water in any sufficient quantity is available for use as cooling tower makeup water at MLPP.

The costs associated with installing transmission pipelines (excavation/drilling, material, labor), in addition to design and permitting costs, are difficult to quantify in the absence of a detailed analysis of various site-specific parameters that will influence the final configuration. The nearest facility with sufficient capacity to satisfy the makeup demand for Units 1 and 2 (4 to 6 mgd for freshwater towers) is located 6 miles north of the facility (Watsonville). The available volume may vary on a daily basis and future demands from agricultural operations may further limit any excess volume available to MLPP.

Based on data compiled for this study and others, the estimated installed cost of a 24-inch prestressed concrete cylinder pipe, sufficient to provide 6 mgd to MLPP, is $300 per linear foot, or approximately $1.6 million per mile. Additional considerations, such as pump capacity and any required treatment, would increase the total cost.

Regulatory concerns beyond the scope of this investigation, however, may make reclaimed water (as a makeup water source) comparable or preferable to marine water from Moss Landing Harbor. Reclaimed water may enable MLPP to eliminate potential conflicts with water discharge limitations or reduce PM_{10} emissions from the cooling tower, which is a concern given the North Central Coast air basin's current nonattainment status.

At any facility where wet cooling towers are a feasible alternative, reclaimed water may be used as a makeup water source. The practicality of its use, however, depends on the overall cost, availability, and additional environmental benefit that may occur.

3.4.5 THERMAL EFFICIENCY

Wet cooling towers at MLPP will increase the condenser inlet water temperature by a range of 13 to 19° F above the surface water temperature, depending on the ambient wet bulb temperature at the time. The generating units at MLPP are designed to operate at the conditions described in Table J–12. The resulting monthly difference between once-through and wet cooling tower condenser inlet temperatures is described in Figure J–7.

Table J–12. Design Thermal Conditions

	Units 1 & 2	Units 6 & 7
Design backpressure (in. HgA)	1.305	1.38
Design water temperature (°F)	56.1	60
Turbine inlet temp (°F)	1,000	1,000
Turbine inlet pressure (psia)	1,849	3,500
Full load heat rate (BTU/kWh)	6,800	9,130

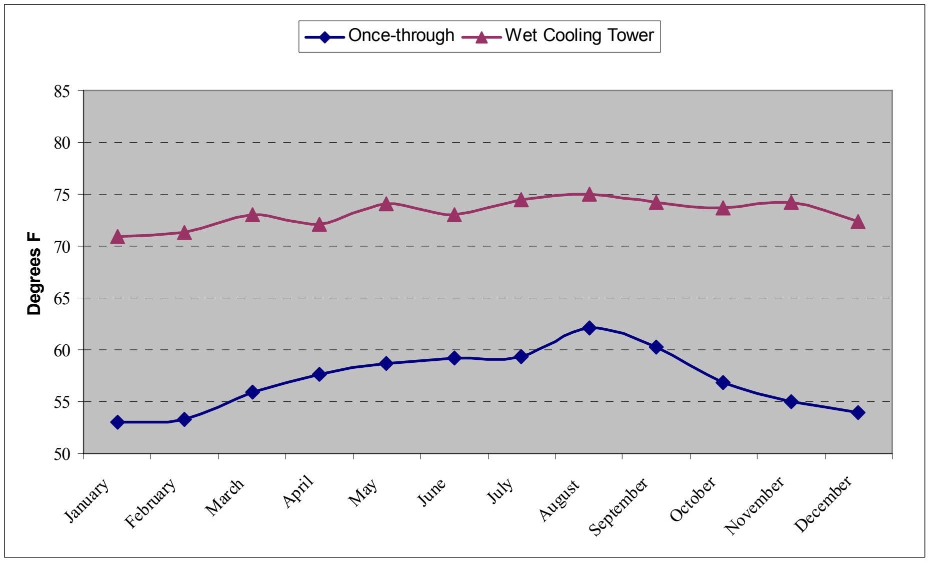

Figure J–7. Condenser Inlet Temperatures

Backpressures for the once-through and wet cooling tower configurations were calculated for each month using the design criteria described in the sections above and ambient climate data (Table J– 6). In general, backpressures associated with the wet cooling tower were elevated by 0.66 to 0.87 inches HgA compared with the current once-through system (Figure J–8 and Figure J–10).

Heat rate adjustments were calculated by comparing the theoretical change in available energy that occurs at different turbine exhaust backpressures, assuming the thermal load and turbine inlet pressure remain constant, i.e., at the full load rating.[4] The relative change at different backpressures was compared with the value calculated for the design conditions (i.e., at design turbine inlet and exhaust backpressures) and plotted as a percentage of the full load operating heat rate to develop estimated correction curves (Figure J–9 and Figure J–11).

The difference between the estimated once-through and closed-cycle heat rates for each month represents the approximate heat rate increase that would be expected when converting to wet cooling towers.

Table J–13 summarizes the annual average heat rate increase for each unit as well as the increase associated with the peak demand period of July-August-September. Monthly values were used to calculate the monetized value of these heat rate changes (Section 4.6). Month-by-month calculations are presented in Appendix A.

[4] Changes in thermal efficiency estimated for MLPP are based on the design specifications provided by the facility. This may not reflect system modifications that might influence actual performance. In addition, the age of the units and the operating protocols used by MLPP might result in different calculations.

Table J-13. Summary of Estimated Heat Rate Increases

	Units 1 & 2	Units 6 & 7
Peak (July-August-September)	0.55%	1.22%
Annual average	0.57%	1.22%

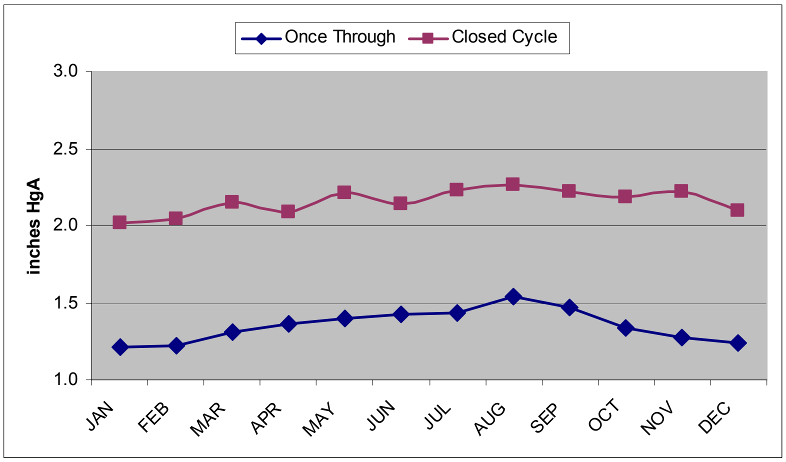

Figure J-8. Estimated Backpressures (Units 1 & 2)

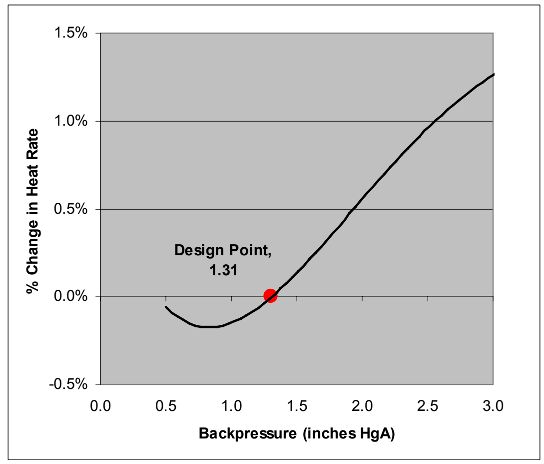

Figure J-9. Estimated Heat Rate Correction (Units 1 & 2)

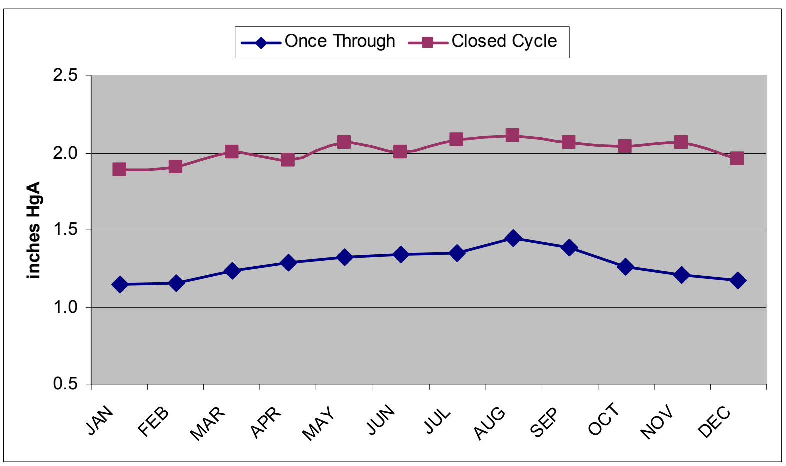

Figure J-10. Estimated Backpressures (Units 6 & 7)

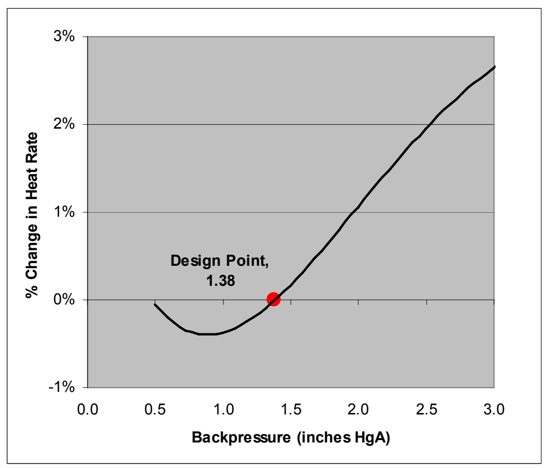

Figure J-11. Estimated Heat Rate Correction (Units 6 & 7)

4.0 RETROFIT COST ANALYSIS

The wet cooling system retrofit estimate for MLPP is based on incorporating conventional wet cooling towers as a replacement for the existing once-through system for each unit. Standard cost elements for this project include the following:

- Direct (cooling tower installation, civil/structural, mechanical, piping, electrical, and demolition)
- Indirect (smaller project costs not itemized)
- Contingency (allowance for unknown project variables)
- Revenue loss from shutdown (net loss in revenue during construction phase)
- Operations and maintenance (non–energy related cooling tower operations)
- Energy penalty (includes increased parasitic use from fans and pumps as well as decreased thermal efficiency)

The cost analysis does not include allowances for elements that are not quantified in this study, such as land acquisition, effluent treatment, or air emission reduction credits. The methodology used to develop cost estimates is discussed in Chapter 5.

4.1 COOLING TOWER INSTALLATION

Table J–14 summarizes the design-and-build cost estimate for each tower developed by vendors, inclusive of all labor and management required for their installation.

Table J–14. Wet Cooling Tower Design-and-Build Cost Estimate

	Units 1 & 2	Units 6 & 7	MLPP total
Number of cells	20	52	**72**
Cost/cell ($)	560,000	530,769	**538,889**
Total MLPP D&B cost ($)	**11,200,000**	**27,600,000**	**38,800,000**

4.2 OTHER DIRECT COSTS

A significant portion of wet cooling tower installation costs result from the various support structures, materials, equipment and labor necessary to prepare the cooling tower site and connect the towers to the condenser. At MLPP, these costs comprise approximately 75 percent of the initial capital cost. Line item costs are detailed in Appendix B.

Deviations from or additions to the general cost elements discussed in Chapter 5 are discussed below. Other direct costs (non–cooling tower) are summarized in Table J–15.

Table J–15. Summary of Other Direct Costs (MLPP Total)

	Equipment ($)	Bulk material ($)	Labor ($)	MLPP total ($)
Civil/structural/piping	9,600,000	48,300,000	43,600,000	**101,500,000**
Mechanical	11,600,000	0	700,000	**12,300,000**
Electrical	3,000,000	5,200,000	4,500,000	**12,700,000**
Demolition	0	0	0	**0**
Total MLPP other direct costs	**24,200,000**	**53,500,000**	**48,800,000**	**126,500,000**

Table J–16. Summary of Other Direct Costs (Units 1 & 2 Only)

	Equipment ($)	Bulk material ($)	Labor ($)	MLPP total ($)
Civil/structural/piping	4,000,000	10,700,000	9,900,000	**24,600,000**
Mechanical	5,000,000	0	300,000	**5,300,000**
Electrical	1,300,000	1,800,000	1,700,000	**4,800,000**
Demolition	0	0	0	**0**
Total MLPP other direct costs	**10,300,000**	**12,500,000**	**11,900,000**	**34,700,000**

- *Civil, Structural, and Piping*
  The distance between Cooling Tower Complex 2 and Units 6 and 7 requires more than 8,000 feet of large diameter pipe to service both cooling towers.
- *Mechanical and Electrical*
  Initial capital costs in this category reflect the new pumps (ten total) to circulate cooling water between the towers and condensers. No new pumps are required to provide makeup water from Moss Landing Harbor. Electrical costs are based on the battery limit after the main feeder breakers.
- *Demolition*
  No demolition costs are required.

4.3 INDIRECT AND CONTINGENCY

Indirect costs are calculated as 25 percent of all direct costs (civil/structural, mechanical, electrical, demolition, and cooling towers).

An additional allowance is included for condenser water box and tube sheet reinforcement to withstand the increased pressures associated with a recirculating system. Each condenser may require reinforcement of the tube sheet bracing with 6-inch x 1-inch steel, and water box reinforcement/replacement with 5/8-inch carbon steel. Based on the estimates outlined in Chapter 5, a conservative estimate of 5 percent of all direct costs is included to account for possible condenser modifications.

The contingency cost is calculated as 25 percent of the sum of all direct and indirect costs, including condenser reinforcement. At MLPP, potential costs in this category include relocating or demolishing small buildings and structures and potential interferences from underground structures.

Soils were not characterized for this analysis. MLPP is situated near sea level adjacent to Moss Landing Harbor and Elkhorn Slough. Subsidence and groundwater intrusion may require additional pilings to support any large structures built at the site. Initial capital costs are summarized in Table J–17.

Table J–17. Summary of Initial Capital Costs

	MLPP cost ($)	Units 1 & 2 cost ($)
Cooling towers	38,800,000	11,200,000
Civil/structural/piping	101,500,000	24,600,000
Mechanical	12,300,000	5,300,000
Electrical	12,700,000	4,800,000
Demolition	0	0
Indirect cost	41,300,000	11,500,000
Condenser modification	8,300,000	2,300,000
Contingency	53,700,000	14,900,000
Total capital cost	**268,600,000**	**74,600,000**

4.4 SHUTDOWN

A portion of the work relating to installing the Unit 6 and 7 wet cooling towers can be completed without significant disruption to the operations of MLPP. Units will be offline depending on the length of time it takes to integrate the new cooling system and conduct acceptance testing. For MLPP, a conservative estimate of 4 weeks per unit was developed. Based on 2006 generating output, however, no shutdown is forecast for either unit.

Units 1 and 2 are combined-cycle units and, as such, typically operate at higher capacity utilization rates than Units 6 and 7. This study assumed some downtime loss during tie-in. If construction were scheduled to coincide with the lowest generating period of the year, Units 1 and 2 would be offline for an estimated 4 weeks during April (based on 2006 output data) and incur an estimated revenue loss of $2 million.

Table J–18. Estimated Revenue Loss from Construction Shutdown (Units 1 & 2)

Estimated output (MWh)	Heat rate (BTU/kWh)	Wholesale fuel price ($/MMBTU)	Wholesale electricity price ($/MWh)	Fuel cost ($)	Gross revenue ($)	Difference ($)
75,342	6,800	5.00	60	2,561,628	10,500,000.00	**1,958,892**

This analysis did not consider shutdown with respect to the required availability of a particular generating unit, nor can it automatically be assumed that the generating profile for 2006 will be the same in each subsequent year. Net output data from 2006 may not reflect any contractual obligations that mandate a particular unit's availability during a given time period.

4.5 OPERATIONS AND MAINTENANCE

Operations and maintenance (O&M) costs for a wet cooling tower system at MLPP include routine maintenance activities; chemicals and treatment systems to control fouling and corrosion in the towers; management and labor; and an allowance for spare parts and replacement. Annual costs are calculated based on the combined tower flow rate using a base cost of $4.00/gpm in Year 1 and $5.80/gpm in Year 12, with an annual escalator of 2 percent (USEPA 2001). Year 12 costs increase based on the assumption that maintenance needs, particularly for spare parts and replacements, will be greater for years 12–20. Annual O&M costs, based on the design circulating water flow for the four cooling towers at MLPP (810,000 gpm), as well as an annual cost for Units 1 and 2 alone (based on a flow of 214,000 gpm) are presented in Table J–19. These costs reflect maximum operation.

Table J–19. Annual O&M Costs (Full Load)

	MLPP total	
	Year 1 ($)	Year 12 ($)
Management/labor	810,000	1,174,500
Service/parts	1,296,000	1,879,200
Fouling	1,134,000	1,644,300
Total MLPP O&M cost	**3,240,000**	**4,698,000**

	Units 1 & 2 only	
	Year 1 ($)	Year 12 ($)
Management/labor	214,000	310,300
Service/parts	342,400	496,480
Fouling	299,600	434,420
Units 1 & 2 O&M cost	**856,000**	**1,241,200**

4.6 ENERGY PENALTY

The energy penalty is divided into two components: increased parasitic use from the added electrical demand from tower fans and pumps; and the decrease in thermal efficiency from elevated turbine backpressures. Monetizing the energy penalty at MLPP requires some assumption as to how the facility will choose to alter its operations to compensate for these changes, if at all. One option would be to accept the reduced amount of revenue-generating electricity available for sale and absorb the economic loss ("production loss option"). A second option would be to increase the firing rate to the turbine (i.e., consume more fuel) and produce the same amount of revenue-generating electricity as had been obtained with the once-through cooling system ("increased fuel option"). The degree to which a facility is able, or prefers, to operate at a higher firing rate, however, produces the more likely scenario—some combination of the two.

Ultimately, the manner in which MLPP would alter operations to address efficiency changes is driven by considerations unknown to this study (e.g., corporate strategy, contractual obligations, operating protocols and turbine pressure tolerances). In all summary cost estimates, this study calculates the energy penalty's monetized value by assuming the facility will use the increased fuel option to compensate for reduced efficiency and generate the amount of electricity equivalent to the estimated shortfall. With this option, the energy penalty is equivalent to the financial cost of additional fuel and is nominally less costly than the production loss option. This option, however, may not reflect long-term costs such as increased maintenance or system degradation that may result from continued operation at a higher-than-designed turbine firing rate. [5]

The energy penalty for MLPP is calculated by first estimating the increased parasitic demand from the cooling tower pumps and fans, expressed as a percentage of each unit's rated capacity. Likewise, the change in the unit's heat rate is also expressed as a capacity percentage.

4.6.1 INCREASED PARASITIC USE (FANS AND PUMPS)

Depending on ambient conditions or the operating load at a given time, MLPP may be able to take one or more cooling tower cells offline and still obtain the required level of cooling. This would also reduce the cumulative electrical demand from the fans. For the purposes of this study, however, operations are evaluated at the design conditions, i.e., full load; no allowance is made for seasonal changes. The increased electrical demand from cooling tower fan operation is summarized in Table J–20.

Table J–20. Cooling Tower Fan Parasitic Use

	Tower Complex 1	Tower Complex 2	MLPP total
Units served	Units 1&2	Units 6&7	--
Generating capacity (MW)	1,080	1,404	**2,484**
Number of fans (one per cell)	20	52	**72**
Motor power per fan (hp)	211	211	--
Total motor power (hp)	4,211	10,947	**15,158**
MW total	3.14	8.16	**11.30**
Fan parasitic use (% of capacity)	**0.29%**	**0.58%**	**0.46%**

Additional circulating water pump capacity for the wet cooling towers will also increase the parasitic electricity usage at MLPP. Makeup water will continue to be withdrawn from Moss Landing Harbor with one of the existing circulating water pumps; the remaining pumps will be retired.

The net increase in pump-related parasitic usage is the difference between the new wet cooling tower configuration (new plus retained pumps) and the existing once-through configuration. For calculation purposes, this study assumes full-load operation to estimate the cost of increased parasitic use. Final estimates, therefore, allocate the retained pump's electrical demand to each

[5] Increasing the thermal load to the turbine will raise the circulating water temperature exiting the condenser. The cooling towers selected for this study are designed with a maximum water return temperature of approximately 120º F. Depending on each unit's operating conditions (i.e., condenser outlet temperature), the degree to which the thermal input to the turbine can be increased may be limited.

tower based on the proportion of the facility's generating capacity it services. Operating fewer towers or tower cells will alter the allocation of the retained pump's electrical demand, but not the total demand.

Because one of the main design assumptions maintains the existing flow rate through each condenser, the new circulating pumps are single speed and are assumed to operate at their full rated capacity when in use. The increased electrical demand associated with cooling tower pump operation is summarized in Table J–21.

Table J–21. Cooling Tower Pump Parasitic Use

	Tower Complex 1	Tower Complex 2	MLPP total
Units served	Units 1 & 2	Units 6 & 7	--
Generating capacity (MW)	1080	1404	**2,484**
Existing pump configuration (hp)	3,600	12,060	**15,660**
New pump configuration (hp)	6,591	15,545	**22,136**
Difference (hp)	2,991	3,485	**6,476**
Difference (MW)	2.2	2.6	**4.8**
Net pump parasitic use (% of capacity)	**0.21%**	**0.19%**	**0.19%**

4.6.2 HEAT RATE CHANGE

Heat rate adjustments were calculated based on each month's ambient climate conditions and reflect the estimated difference between operations with once-through and wet cooling tower systems. As noted above, the energy penalty analysis assumes MLPP will increase its fuel consumption to compensate for lost efficiency and the increased parasitic load from fans and pumps. The higher turbine firing rate will increase the thermal load rejected to the condenser, which, in turn, results in a higher backpressure value and corresponding increase in the heat rate. No data are available describing the changes in turbine backpressures above the design thermal loads. For the purposes of monetizing the energy penalty only, this study conservatively assumed an additional increase in the heat rate of 0.5 percent at the higher firing rate; the actual effect at MLPP may be greater or less. Changes in the heat rate for each unit at MLPP are presented in Figure J–12 and Figure J–13.

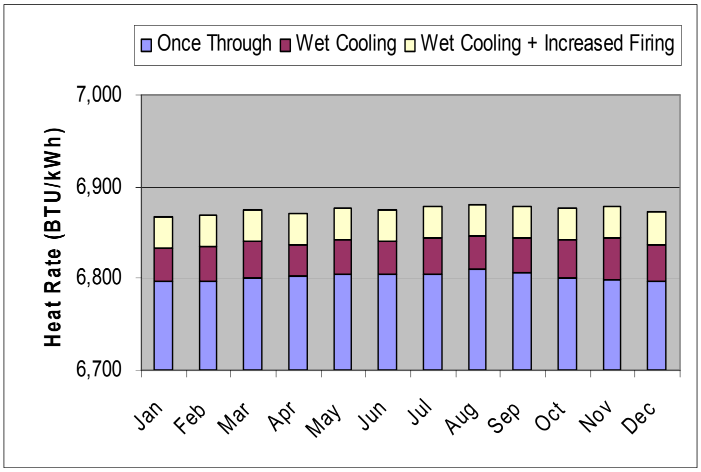

Figure J–12. Estimated Heat Rate Change (Units 1 & 2)

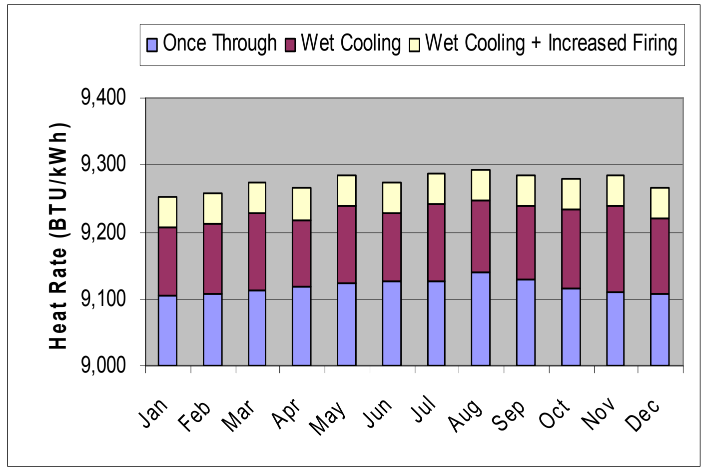

Figure J–13. Estimated Heat Rate Change (Units 6 & 7)

4.6.3 CUMULATIVE ESTIMATE

Using the increased fuel option, the energy penalty's cumulative value is obtained by first calculating the relative costs of generation ($/MWh) for the once-through system and the wet cooling system adjusted for a higher turbine firing rate. The cost of generation for MLPP is based on the relative heat rates developed in Section 4.6.2 and the average monthly wholesale natural gas cost ($/MMBTU) (ICE 2006a). The difference between these two values represents the monthly increased cost, per MWh, that results from converting to wet cooling towers. This value is then applied to the net MWh generated for the each month and summed to calculate the annual cost.

Based on 2006 output data, the Year 1 energy penalty for MLPP will be approximately $3.2 million. In contrast, the energy penalty's value calculated with the production loss option would be approximately $5.2 million. Together, these values represent the range of potential energy penalty costs for MLPP. Table J–22 and Table J–23 summarize the Year 1 energy penalty estimate for each unit using the increased fuel option.

Table J–22. Units 1 & 2 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	6,796	40.78	6,868	41.21	0.43	292,626	124,756
February	5.50	6,797	37.38	6,869	37.78	0.40	317,274	125,491
March	4.75	6,800	32.30	6,874	32.65	0.35	203,065	71,602
April	4.75	6,802	32.31	6,871	32.64	0.33	75,342	24,666
May	4.75	6,804	32.32	6,877	32.67	0.35	187,163	65,528
June	5.00	6,805	34.02	6,874	34.37	0.35	416,025	144,340
July	6.50	6,805	44.23	6,878	44.71	0.48	586,207	279,840
August	6.50	6,810	44.26	6,880	44.72	0.46	682,917	312,275
September	4.75	6,806	32.33	6,878	32.67	0.34	665,273	225,397
October	5.00	6,801	34.01	6,876	34.38	0.38	687,946	258,446
November	6.00	6,799	40.79	6,878	41.27	0.47	626,008	296,723
December	6.50	6,797	44.18	6,872	44.67	0.48	622,298	300,757
							Units 1 & 2 total	**2,229,821**

Table J–23. Units 6 & 7 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	9,105	54.63	9,254	55.52	0.89	0	0
February	5.50	9,106	50.08	9,257	50.92	0.83	0	0
March	4.75	9,113	43.29	9,274	44.05	0.76	0	0
April	4.75	9,119	43.31	9,265	44.01	0.69	22,064	15,287
May	4.75	9,123	43.33	9,284	44.10	0.77	209,176	160,939
June	5.00	9,125	45.62	9,274	46.37	0.74	146,878	109,281
July	6.50	9,126	59.32	9,288	60.37	1.05	373,329	393,157
August	6.50	9,138	59.40	9,293	60.40	1.00	211,717	212,737
September	4.75	9,130	43.37	9,286	44.11	0.74	62,095	46,037
October	5.00	9,116	45.58	9,281	46.40	0.82	0	0
November	6.00	9,110	54.66	9,285	55.71	1.05	0	0
December	6.50	9,107	59.20	9,267	60.24	1.04	17,955	18,618
							Units 6 & 7 total	**956,056**

4.7 NET PRESENT COST

The Net Present Cost (NPC) of a wet cooling system retrofit at MLPP is the sum of all annual expenditures over the project's 20-year life span discounted according to the year in which the expense is incurred and the selected discount rate. The NPC represents the total change in revenue streams, in 2007 dollars, that MLPP can expect over 20 years as a direct result of converting to wet cooling towers. The following values were used to calculate the NPC at a 7 percent discount rate:

- *Capital and Start-up.* Includes all capital, indirect, contingency, and shutdown costs. All costs in this category are incurred in Year 0. (See Table J–16.)
- *Annual O&M.* Base cost values for Year 1 and Year 12 are adjusted for subsequent years using a 2 percent year-over-year escalator. Because MLPP overall has a relatively low capacity utilization factor, O&M costs for the NPC calculation were estimated at 60 percent of their maximum value. (See Table J–17.)
- *Annual Energy Penalty.* Insufficient information is available to this study to forecast future generating output at MLPP. In lieu of annual estimates, this study uses the net MWh output from 2006 as the calculation basis for Years 1 through 20. Wholesale prices include a year-over-year price escalator of 5.8 percent (based on the Producer Price Index). The energy penalty values are based on the increased fuel option discussed in Section 4.6. (See Table J–20 and Table J–21.)

Using these values, the NPC_{20} for MLPP is \$350 million. For Units 1 and 2 only, the NPC_{20} is \$123 million. Appendix C and Appendix D contain detailed annual calculations for MLPP used to develop this cost.

4.8 ANNUAL COST

The annual cost incurred by MLPP for a wet cooling tower retrofit is the sum of annual amortized capital costs plus the annual average of O&M and energy penalty expenditures. Capital costs are amortized at a 7 percent discount rate over 20 years. O&M and energy penalty costs are calculated in the same manner as for the NPC_{20} (Section 4.7). Revenue losses from a construction-related shutdown, if any, are incurred in Year 0 only and not included in the annual cost summarized in Table J–24.

Table J–24. Annual Cost

	Discount rate (%)	Capital Cost ($)	Annual O&M ($)	Annual energy penalty ($)	Annual cost ($)
MLPP total	7.00	25,400,000	2,600,000	5,800,000	**33,800,000**
Units 1 & 2 only	7.00	7,100,000	800,000	4,000,000	**11,900,000**

4.9 COST-TO-GROSS REVENUE COMPARISON

Limited financial data are available to conduct a detailed analysis of the economic impact that a wet cooling system retrofit will have on MLPP's annual revenues. The facility's gross annual revenue can be approximated using 2006 net generating data (CEC 2006) and average wholesale prices for electricity as recorded at the SP 15 trading hub (ICE 2006b). This estimate, therefore, does not reflect any changes that may result from different wholesale prices or contract agreements that may increase or decrease the gross revenue summarized below, nor does it account for annual fixed revenue requirements or other variable costs.

The estimate of gross annual revenue from electricity sales at MLPP is a straightforward calculation that multiplies the monthly wholesale cost of electricity by the amount generated for the particular month. The estimated gross revenue for MLPP is summarized in Table J–25. A comparison of annual costs to annual gross revenue is summarized in Table J–26.

Table J–25. Estimated Gross Revenue

	Wholesale price ($/MWh)	Net generation (MWh)		Estimated gross revenue ($)		
		Units 1 & 2	Units 6 & 7	Units 1 & 2	Units 6 & 7	MLPP total
January	66	292,626	0	19,313,316	0	**19,313,316**
February	61	317,274	0	19,353,714	0	**19,353,714**
March	51	203,065	0	10,356,315	0	**10,356,315**
April	51	75,342	22,064	3,842,442	1,125,264	**4,967,706**
May	51	187,163	209,176	9,545,313	10,667,976	**20,213,289**
June	55	416,025	146,878	22,881,375	8,078,290	**30,959,665**
July	91	586,207	373,329	53,344,837	33,972,939	**87,317,776**
August	73	682,917	211,717	49,852,941	15,455,341	**65,308,282**
September	53	665,273	62,095	35,259,469	3,291,035	**38,550,504**
October	57	687,946	0	39,212,922	0	**39,212,922**
November	66	626,008	0	41,316,528	0	**41,316,528**
December	67	622,298	17,955	41,693,966	1,202,985	**42,896,951**
MLPP total		**5,362,144**	**1,043,214**	**345,973,138**	**73,793,830**	**419,766,968**

Table J–26. Cost-Revenue Comparison

	Estimated gross annual revenue ($)	Initial capital		O&M		Energy penalty		Total annual cost	
		Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross
MLPP total	419,800,000	25,400,000	6.1	2,600,000	0.6	5,800,000	1.4	**33,800,000**	**8.1**
Units 1 & 2 only	346,000,000	7,100,000	2.1	800,000	0.2	4,000,000	1.2	**11,900,000**	**3.4**

5.0 OTHER TECHNOLOGIES

Within the scope of this study, and using the OPC resolution's stated goal of reducing impingement and entrainment by 90–95 percent as a benchmark, the effectiveness of other technologies commonly used to address such impacts could not be conclusively determined for use at MLPP. As with many existing facilities, the location and configuration of the site complicates the use of some technologies that might be used successfully elsewhere. A more detailed analysis that also comprises a biological evaluation may determine the applicability of one or more of these technologies to MLPP. A brief summary of the applicability of these technologies follows.

5.1 MODIFIED RISTROPH SCREENS—FINE MESH

The principal concern with this technology is the successful return of viable organisms captured on the screens to the source water body. MLPP currently withdraws its cooling water through a shoreline CWIS on the eastern bank of Moss Landing Harbor. Modifying the existing traveling screens to include fine mesh panels and a return system would require expanding the existing CWIS and identifying a suitable return location to prevent re-impingement. These modifications, and the potential for success, are plausible but require detailed investigation of the potentially affected species in Moss Landing Harbor before a conclusive determination can be made.

5.2 BARRIER NETS

The confined area within Moss Landing Harbor is a significant constraint on the use of a barrier net. For this reason, in addition to their ineffectiveness in reducing entrainment, barrier nets were not considered further in this study.

5.3 AQUATIC FILTRATION BARRIERS

Aquatic filtration barriers (AFBs), which are larger than barrier nets, are more limited than barrier nets for deployment at MLPP. Placement within Moss Landing Harbor is infeasible.

5.4 VARIABLE SPEED DRIVES

Variable speed drives (VSDs) were not considered for analysis at MLPP because the technology alone cannot be expected to achieve the desired level of reductions in impingement and entrainment, nor could it be combined with another technology to yield the desired reductions. Pumps that have been retrofitted with VSDs can reduce overall flow intake volumes by 10–35 percent over the current once-through configuration (USEPA 2001). The actual reduction, however, will vary based on the cooling water demand at different times of the year. At peak demand, the pumps will essentially function as standard circulating water pumps and withdraw water at the maximum rated capacity, thus negating any potential benefit. Use of VSDs may be an economically desirable option when pumps are retrofitted or replaced for other reasons, but were not considered further for this study.

5.5 CYLINDRICAL FINE MESH WEDGEWIRE

Fine-mesh cylindrical wedgewire screens have not been deployed or evaluated at coastal facilities for applications as large as would be required at MLPP (approximately 1,224 mgd). To function as intended, cylindrical wedgewire screens must be submerged in a water body with a consistent ambient current of 0.5 fps. Ideally, this current would be unidirectional so that screens may be oriented properly and any debris impinged on the screens will be carried downstream when the airburst cleaning system is activated.

MLPP currently withdraws cooling water from Moss Landing Harbor. Space constraints and navigation concerns prohibit the placement of any large cylindrical screens in the channel or bay, let alone the 10 to 12 84-inch-diameter screens that would be required to supply the facility with adequate volumes of water. The only theoretical location available for MLPP would be offshore in Monterey Bay, west of the entrance to Moss Landing Harbor.

To attain sufficient depth (approximately 20 feet) and an ambient current that might allow deployment, screens would need to be located 2,000 feet or more offshore. The bathymetry of Monterey Bay in the area west of Moss Landing Harbor is rocky and drops rapidly into the Monterey submarine canyon, complicating placement of wedgewire screens. Discussions with vendors who design these systems indicated that distances more than 1,000 to 1,500 feet become problematic due to the airburst system's inability to maintain adequate pressure for sufficient cleaning (Someah 2007). Together, these considerations preclude further evaluation of fine-mesh cylindrical wedgewire screens at MLPP.

6.0 REFERENCES

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Appendix A. Once-Through and Closed-Cycle Thermal Performance

Month	Parameter	Units 1 & 2			Units 6 & 7		
		Once through	Closed cycle	Net increase	Once through	Closed cycle	Net increase
JAN	Backpressure (in. HgA)	1.21	2.02	**0.81**	1.15	1.89	**0.74**
	Heat rate Δ (%)	*-0.15*	*1.39*	***1.54***	*-0.27*	*0.85*	***1.12***
FEB	Backpressure (in. HgA)	1.22	2.04	**0.82**	1.16	1.91	**0.75**
	Heat rate Δ (%)	*-0.13*	*1.45*	***1.58***	*-0.26*	*0.89*	***1.15***
MAR	Backpressure (in. HgA)	1.31	2.15	**0.84**	1.23	2.00	**0.77**
	Heat rate Δ (%)	*-0.01*	*1.67*	***1.67***	*-0.19*	*1.07*	***1.26***
APR	Backpressure (in. HgA)	1.37	2.09	**0.72**	1.29	1.95	**0.66**
	Heat rate Δ (%)	*0.09*	*1.54*	***1.45***	*-0.12*	*0.97*	***1.09***
MAY	Backpressure (in. HgA)	1.40	2.21	**0.81**	1.32	2.06	**0.74**
	Heat rate Δ (%)	*0.15*	*1.80*	***1.65***	*-0.08*	*1.19*	***1.27***
JUN	Backpressure (in. HgA)	1.43	2.15	**0.72**	1.34	2.00	**0.66**
	Heat rate Δ (%)	*0.19*	*1.66*	***1.47***	*-0.06*	*1.07*	***1.12***
JUL	Backpressure (in. HgA)	1.43	2.23	**0.80**	1.35	2.08	**0.73**
	Heat rate Δ (%)	*0.20*	*1.84*	***1.64***	*-0.05*	*1.22*	***1.27***
AUG	Backpressure (in. HgA)	1.54	2.27	**0.73**	1.45	2.11	**0.67**
	Heat rate Δ (%)	*0.40*	*1.91*	***1.51***	*0.09*	*1.28*	***1.19***
SEP	Backpressure (in. HgA)	1.47	2.22	**0.75**	1.38	2.07	**0.69**
	Heat rate Δ (%)	*0.27*	*1.82*	***1.55***	*-0.01*	*1.20*	***1.20***
OCT	Backpressure (in. HgA)	1.34	2.19	**0.85**	1.26	2.04	**0.78**
	Heat rate Δ (%)	*0.04*	*1.75*	***1.71***	*-0.16*	*1.14*	***1.30***
NOV	Backpressure (in. HgA)	1.27	2.22	**0.95**	1.20	2.07	**0.86**
	Heat rate Δ (%)	*-0.06*	*1.81*	***1.87***	*-0.22*	*1.19*	***1.41***
DEC	Backpressure (in. HgA)	1.24	2.10	**0.86**	1.17	1.96	**0.79**
	Heat rate Δ (%)	*-0.10*	*1.57*	***1.68***	*-0.25*	*1.00*	***1.24***

Note: Heat rate delta represents change from design value calculated according to estimated ambient conditions for each month.

Appendix B. Itemized Capital Costs

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
CIVIL / STRUCTURAL / PIPING	--	--	--	--	--	--	--	--	--	--
Allocation for other accessories (bends, water hammers…)	lot	1	--	--	500,000	500,000	4,000.00	106	424,000	**924,000**
Allocation for pipe racks (approx 3000 ft) and cable racks	t	300	--	--	2,500	750,000	17.00	105	535,500	**1,285,500**
Allocation for sheet piling and dewatering	lot	2	--	--	500,000	1,000,000	5,000.00	100	1,000,000	**2,000,000**
Allocation for testing pipes	lot	2	--	--	--	--	2,000.00	95	380,000	**380,000**
Allocation for Tie-Ins to existing condenser's piping	lot	1	--	--	250,000	250,000	2,000.00	106	212,000	**462,000**
Allocation for trust blocks	lot	2	--	--	25,000	50,000	250.00	95	47,500	**97,500**
Backfill for PCCP pipe (reusing excavated material)	m3	52,000	--	--	--	--	0.04	200	416,000	**416,000**
Bedding for PCCP pipe	m3	7,700	--	--	25	192,500	0.04	200	61,600	**254,100**
Bend for PCCP pipe 120" diam (allocation)	ea	15	--	--	35,000	525,000	100.00	95	142,500	**667,500**
Bend for PCCP pipe 42" & 48" diam (allocation)	ea	30	--	--	5,000	150,000	25.00	95	71,250	**221,250**
Bend for PCCP pipe 72" diam (allocation)	ea	6	--	--	18,000	108,000	40.00	95	22,800	**130,800**
Bend for PCCP pipe 84" diam (allocation)	ea	8	--	--	20,000	160,000	50.00	95	38,000	**198,000**
Building architectural (siding, roofing, doors, painting…etc)	ea	4	--	--	57,500	230,000	690.00	75	207,000	**437,000**
Butterfly valves 120" c/w allocation for actuator & air lines	ea	4	252,000	1,008,000	--	--	80.00	106	33,920	**1,041,920**
Butterfly valves 30" c/w allocation for actuator & air lines	ea	72	30,800	2,217,600	--	--	50.00	106	381,600	**2,599,200**
Butterfly valves 48" c/w allocation for actuator & air lines	ea	16	46,200	739,200	--	--	50.00	106	84,800	**824,000**
Butterfly valves 60" c/w allocation for actuator & air lines	ea	8	75,600	604,800	--	--	60.00	106	50,880	**655,680**
Butterfly valves 72" c/w allocation for actuator & air lines	ea	12	96,600	1,159,200	--	--	75.00	106	95,400	**1,254,600**
Butterfly valves 84" c/w allocation for actuator & air lines	ea	8	124,600	996,800	--	--	75.00	106	63,600	**1,060,400**
Butterfly valves 96" c/w allocation for actuator & air lines	ea	8	151,200	1,209,600	--	--	75.00	106	63,600	**1,273,200**
Check valves 48"	ea	14	66,000	924,000	--	--	24.00	106	35,616	**959,616**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Check valves 84"	ea	4	178,000	712,000	--	--	36.00	106	15,264	**727,264**
Concrete basin walls (all in)	m3	1,082	--	--	225	243,450	8.00	75	649,200	**892,650**
Concrete elevated slabs (all in)	m3	1,117	--	--	250	279,250	10.00	75	837,750	**1,117,000**
Concrete for transformers and oil catch basin (allocation)	m3	200	--	--	250	50,000	10.00	75	150,000	**200,000**
Concrete slabs on grade (all in)	m3	8,872	--	--	200	1,774,400	4.00	75	2,661,600	**4,436,000**
Ductile iron cement pipe 12" diam. for fire water line	ft	3,000	--	--	100	300,000	0.60	95	171,000	**471,000**
Excavation and backfill for fire line, blowdown & make-up (using excavated material for backfill except for bedding)	m3	29,000	--	--	--	--	0.08	200	464,000	**464,000**
Excavation for PCCP pipe	m3	87,500	--	--	--	--	0.04	200	700,000	**700,000**
Fencing around transformers	m	50	--	--	30	1,500	1.00	75	3,750	**5,250**
Flange for PCCP joints 120"	ea	8	--	--	39,795	318,360	40.00	95	30,400	**348,760**
Flange for PCCP joints 30"	ea	72	--	--	2,260	162,720	16.00	95	109,440	**272,160**
Flange for PCCP joints 48"	ea	2	--	--	5,000	10,000	20.00	95	3,800	**13,800**
Flange for PCCP joints 72"	ea	4	--	--	9,860	39,440	25.00	95	9,500	**48,940**
Flange for PCCP joints 84"	ea	8	--	--	13,210	105,680	30.00	95	22,800	**128,480**
Foundations for pipe racks and cable racks	m3	700	--	--	250	175,000	8.00	75	420,000	**595,000**
FRP flange 30"	ea	288	--	--	1,679	483,595	50.00	106	1,526,400	**2,009,995**
FRP flange 48"	ea	60	--	--	3,000	180,000	75.00	106	477,000	**657,000**
FRP flange 60"	ea	24	--	--	7,786	186,854	100.00	106	254,400	**441,254**
FRP flange 72"	ea	8	--	--	20,888	167,101	200.00	106	169,600	**336,701**
FRP flange 84"	ea	16	--	--	33,382	534,104	300.00	106	508,800	**1,042,904**
FRP flange 96"	ea	8	--	--	40,000	320,000	500.00	106	424,000	**744,000**
FRP pipe 120" diam.	ft	3,000	--	--	4,257	12,771,000	2.00	106	636,000	**13,407,000**
FRP pipe 72" diam.	ft	4,000	--	--	851	3,405,600	1.20	106	508,800	**3,914,400**
FRP pipe 84" diam.	ft	80	--	--	946	75,680	1.50	106	12,720	**88,400**
Harness clamp 120" c/w internal testable joint for PCCP pipe	ea	500	--	--	4,310	2,155,000	25.00	95	1,187,500	**3,342,500**
Harness clamp 48" & 42" c/w internal testable joint	ea	310	--	--	2,000	620,000	16.00	95	471,200	**1,091,200**
Harness clamp 72" c/w internal testable joint	ea	50	--	--	2,440	122,000	18.00	95	85,500	**207,500**
Harness clamp 84" c/w internal testable joint	ea	180	--	--	2,845	512,100	20.00	95	342,000	**854,100**
Joint for FRP pipe 120" diam.	ea	150	--	--	22,562	3,384,315	1,200.00	106	19,080,000	**22,464,315**
Joint for FRP pipe 72" diam.	ea	100	--	--	3,122	312,180	200.00	106	2,120,000	**2,432,180**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Joint for FRP pipe 84" diam.	ea	4	--	--	5,014	20,055	300.00	106	127,200	**147,255**
PCCP pipe 120" diam.	ft	8,000	--	--	1,285	10,280,000	3.50	95	2,660,000	**12,940,000**
PCCP pipe 42" dia. for blowdown	ft	3,000	--	--	195	585,000	0.90	95	256,500	**841,500**
PCCP pipe 48" dia. for make-up water line	ft	3,200	--	--	260	832,000	1.00	95	304,000	**1,136,000**
PCCP pipe 72" diam.	ft	1,000	--	--	507	507,000	1.30	95	123,500	**630,500**
PCCP pipe 84" diam.	ft	3,600	--	--	562	2,023,200	1.50	95	513,000	**2,536,200**
Riser (FRP pipe 30" diam X 40ft)	ea	72	--	--	14,603	1,051,445	100.00	106	763,200	**1,814,645**
Structural steel for building	t	190	--	--	2,500	475,000	20.00	105	399,000	**874,000**
CIVIL / STRUCTURAL / PIPING TOTAL	**--**	**--**	**--**	**9,571,200**	**--**	**48,378,530**	**--**	**--**	**43,566,390**	**101,516,120**
ELECTRICAL	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**
4.16 kv cabling feeding MCC's	m	5,000	--	--	75	375,000	0.40	106	212,000	**587,000**
4.16kV switchgear - 7 breakers	ea	1	325,000	325,000	--	--	230.00	106	24,380	**349,380**
480 volt cabling feeding MCC's	m	2,000	--	--	70	140,000	0.40	106	84,800	**224,800**
480V Switchgear - 1 breaker 3000A	ea	12	30,000	360,000	--	--	80.00	106	101,760	**461,760**
Allocation for automation and control	lot	1	--	--	1,300,000	1,300,000	13,000.00	106	1,378,000	**2,678,000**
Allocation for cable trays and duct banks	m	4,500	--	--	75	337,500	1.00	106	477,000	**814,500**
Allocation for lighting and lightning protection	lot	1	--	--	200,000	200,000	2,000.00	106	212,000	**412,000**
Dry Transformer 2MVA xxkV-480V	ea	12	100,000	1,200,000	--	--	100.00	106	127,200	**1,327,200**
Lighting & electrical services for pump house building	ea	4	--	--	20,000	80,000	250.00	106	106,000	**186,000**
Local feeder for 1000 HP motor 4160 V (up to MCC)	ea	6	--	--	40,000	240,000	150.00	106	95,400	**335,400**
Local feeder for 200 HP motor 460 V (up to MCC)	ea	72	--	--	15,000	1,080,000	140.00	106	1,068,480	**2,148,480**
Local feeder for 4000 HP motor 4160 V (up to MCC)	ea	4	--	--	50,000	200,000	200.00	106	84,800	**284,800**
Oil Transformer 10/13.3MVA xx-4.16kV	ea	4	190,000	760,000	--	--	150.00	106	63,600	**823,600**
Primary breaker(xxkV)	ea	8	45,000	360,000	--	--	60.00	106	50,880	**410,880**
Primary feed cabling (assumed 13.8 kv)	m	7,000	--	--	175	1,225,000	0.50	106	371,000	**1,596,000**
ELECTRICAL TOTAL	**--**	**--**	**--**	**3,005,000**	**--**	**5,177,500**	**--**	**--**	**4,457,300**	**12,639,800**
MECHANICAL	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**
Allocation for ventilation of buildings	ea	4	25,000	100,000	--	--	250.00	106	106,000	**206,000**
Cooling tower for unit 6	lot	1	13,800,000	13,800,000	--	--	--	--	--	**13,800,000**
Cooling tower for unit 1	lot	1	5,600,000	5,600,000	--	--	--	--	--	**5,600,000**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Cooling tower for unit 2	lot	1	5,600,000	5,600,000	--	--	--	--	--	**5,600,000**
Cooling tower for unit 7	lot	1	13,800,000	13,800,000	--	--	--	--	--	**13,800,000**
Overhead crane 30 ton in (in pump house)	ea	4	75,000	300,000	--	--	100.00	106	42,400	**342,400**
Pump 4160 V 1000 HP	ea	6	800,000	4,800,000	--	--	400.00	106	254,400	**5,054,400**
Pump 4160 V 4000 HP	ea	4	1,600,000	6,400,000	--	--	800.00	106	339,200	**6,739,200**
MECHANICAL TOTAL	**--**	**--**	**--**	**50,400,000**	**--**	**0**	**--**	**--**	**742,000**	**51,142,000**

Appendix C. Net Present Cost Calculation—All Units

Project year	Capital/start-up ($)	O & M ($)	Energy penalty ($)		Total ($)	Annual discount factor	Present value ($)
			Units 1 & 2	Units 6 & 7			
0	270,558,892	--	--		270,558,892	1	**270,558,892**
1	--	1,944,000	2,229,820	956,057	5,129,877	0.9346	**4,794,383**
2	--	1,982,880	2,359,818	1,011,795	5,354,493	0.8734	**4,676,615**
3	--	2,022,538	2,497,396	1,070,783	5,590,716	0.8163	**4,563,701**
4	--	2,062,988	2,642,994	1,133,209	5,839,192	0.7629	**4,454,719**
5	--	2,104,248	2,797,080	1,199,275	6,100,604	0.713	**4,349,731**
6	--	2,146,333	2,960,150	1,269,193	6,375,676	0.6663	**4,248,113**
7	--	2,189,260	3,132,727	1,343,187	6,665,174	0.6227	**4,150,404**
8	--	2,233,045	3,315,365	1,421,495	6,969,905	0.582	**4,056,485**
9	--	2,277,706	3,508,651	1,504,368	7,290,725	0.5439	**3,965,425**
10	--	2,323,260	3,713,205	1,592,073	7,628,538	0.5083	**3,877,586**
11	--	2,369,725	3,929,685	1,684,891	7,984,301	0.4751	**3,793,341**
12	--	2,875,176	4,158,786	1,783,120	8,817,081	0.444	**3,914,784**
13	--	2,932,680	4,401,243	1,887,076	9,220,998	0.415	**3,826,714**
14	--	2,991,333	4,657,835	1,997,092	9,646,260	0.3878	**3,740,820**
15	--	3,051,160	4,929,387	2,113,523	10,094,069	0.3624	**3,658,091**
16	--	3,112,183	5,216,770	2,236,741	10,565,694	0.3387	**3,578,601**
17	--	3,174,427	5,520,908	2,367,143	11,062,478	0.3166	**3,502,380**
18	--	3,237,915	5,842,777	2,505,147	11,585,839	0.2959	**3,428,250**
19	--	3,302,673	6,183,411	2,651,198	12,137,282	0.2765	**3,355,958**
20	--	3,368,727	6,543,904	2,805,762	12,718,393	0.2584	**3,286,433**
Total							**349,781,426**

Appendix D. Net Present Cost Calculation—Units 1 & 2

Project year	Capital / startup ($)	O & M ($)	Energy penalty ($) Units 1 & 2	Total ($)	Annual discount factor	Present value ($)
0	76,658,892	--	--	76,658,892	1	**76,658,892**
1	--	642,000	2,229,820	2,871,820	0.9346	**2,684,003**
2	--	654,840	2,359,818	3,014,658	0.8734	**2,633,003**
3	--	667,937	2,497,396	3,165,333	0.8163	**2,583,861**
4	--	681,296	2,642,994	3,324,289	0.7629	**2,536,100**
5	--	694,921	2,797,080	3,492,002	0.713	**2,489,797**
6	--	708,820	2,960,150	3,668,970	0.6663	**2,444,635**
7	--	722,996	3,132,727	3,855,723	0.6227	**2,400,959**
8	--	737,456	3,315,365	4,052,821	0.582	**2,358,742**
9	--	752,205	3,508,651	4,260,856	0.5439	**2,317,480**
10	--	767,249	3,713,205	4,480,455	0.5083	**2,277,415**
11	--	782,594	3,929,685	4,712,279	0.4751	**2,238,804**
12	--	949,518	4,158,786	5,108,304	0.444	**2,268,087**
13	--	968,508	4,401,243	5,369,751	0.415	**2,228,447**
14	--	987,879	4,657,835	5,645,714	0.3878	**2,189,408**
15	--	1,007,636	4,929,387	5,937,023	0.3624	**2,151,577**
16	--	1,027,789	5,216,770	6,244,559	0.3387	**2,115,032**
17	--	1,048,345	5,520,908	6,569,253	0.3166	**2,079,825**
18	--	1,069,311	5,842,777	6,912,088	0.2959	**2,045,287**
19	--	1,090,698	6,183,411	7,274,109	0.2765	**2,011,291**
20	--	1,112,512	6,543,904	7,656,415	0.2584	**1,978,418**
Total						**122,691,063**

K. Ormond Beach Generating Station

Reliant Energy, Inc—Oxnard, CA

Contents

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Appendices

1.0 GENERAL SUMMARY

Retrofitting the existing once-through cooling system at Ormond Beach Generating Station (OBGS) with closed-cycle wet cooling towers poses several significant challenges with respect to potential siting locations and conflicts with local use restrictions. The facility's compact dimensions, the layout of existing structures and the site's proximity to state beaches limit the different wet cooling tower configurations that could be evaluated. In addition, the location of OBGS approximately 2.5 miles west of Pt. Mugu Naval Air Station makes it likely that plume abatement would be necessary to prevent interference with flight operations. Plume-abated cooling towers, therefore, are the preferred option for OBGS.

Despite the probability that plume-abated towers would be required at OBGS, a workable configuration could not be developed. In recent years, Reliant Energy, Inc. and the previous owner—Southern California Edison (SCE)—have transferred portions of the original property to state and local conservation agencies as part of ongoing efforts to restore the Ormond Beach wetlands. This has reduced the site's total size by more than half. The facility's compact dimensions, the layout of existing structures and the site's proximity to state beaches limit the different wet cooling tower configurations that could be evaluated. The current size of the OBGS property and the layout of essential structures, however, do not allow for the placement of plume-abated cooling towers in any reasonable configuration at OBGS.

Based on these factors, the preferred option for OBGS is considered logistically infeasible.

If plume-abatement cooling towers were not required, a conventional tower design could be configured at the existing location. The discussion in this chapter, and all cost estimates, evaluates the alternative design based on conventional cooling towers.

The cooling tower configuration designed under the alternative option complies with all identified local use restrictions and includes necessary mitigation measures, where applicable.

1.1 COST

Initial capital and net present costs associated with installing and operating wet cooling towers at OBGS are summarized in Table K–1. Annualized costs based on 20-year average values for the various cost elements are summarized in Table K–2.

Table K–1. Cumulative Cost Summary

Cost category	Cost ($)	Cost per MWh (rated capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Total capital and start-up [a]	132,500,000	10.08	280
NPC_{20} [b]	149,800,000	11.40	317

[a] Includes all costs associated with the cooling tower construction and installation and shutdown loss, if any.
[b] NPC_{20} includes all capital costs, operation and maintenance costs, and energy penalty costs over 20 years discounted at 7 percent.

Table K–2. Annual Cost Summary

Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Capital and start-up	12,500,000	0.95	26.43
Operations and maintenance	700,000	0.05	1.48
Energy penalty	1,100,000	0.08	2.33
Total OBGS annual cost	**14,300,000**	**1.08**	**30.24**

1.2 ENVIRONMENTAL

Environmental changes associated with a cooling tower retrofit for OBGS are summarized in Table K–3 and discussed further in Section 3.4.

Table K–3. Environmental Summary

		Unit 1	Unit 2
Water use	Design intake volume (gpm)	227,000	227,000
	Cooling tower makeup water (gpm)	16,200	16,200
	Reduction from capacity (%)	93	93
Energy efficiency [a]	Summer heat rate increase (%)	1.90	1.90
	Summer energy penalty (%)	2.77	2.77
	Annual heat rate increase (%)	1.69	1.69
	Annual energy penalty (%)	2.57	2.57
Direct air emissions [b]	PM_{10} emissions (tons/yr) (maximum capacity)	131	131
	PM_{10} emissions (tons/yr) (2006 capacity utilization)	0.32	9.1

[a] Reflects the comparative increase between once-through and wet cooling systems, but does not account for any operational changes to address the change in efficiency, such as increased fuel consumption (see Section 4.6).

[b] Reflects emissions from the cooling tower only; does not include any increase in stack emissions.

1.3 OTHER POTENTIAL FACTORS

As noted above, the preferred option is considered infeasible at this location.

The alternative option (conventional cooling towers) can only be sited by constructing 4 inline towers on the north side of the property close to the switchyard and transmission lines. This location would be immediately upwind and potentially subject these structures to the adverse effects of salt drift deposition.

Siting constraints are discussed further in Section 3.2.3.

2.0 BACKGROUND

OBGS is a natural gas–fired steam electric generating facility located in the city of Oxnard, Ventura County, owned and operated by Reliant Energy, Inc. OBGS currently operates two conventional steam turbine units (Unit 1 and Unit 2) with a combined generating capacity of 1,500 MW. The facility occupies approximately 37 acres of a 693-acre industrial site adjacent to Ormond Beach along the Pacific Ocean, approximately 2.5 miles southeast of Port Hueneme. (See Table K–4 and Figure K–1.)

Table K–4. General Information

Unit	In-service year	Rated capacity (MW)	2006 capacity utilization [a]	Condenser cooling water flow (gpm)
Unit 1	1959	215	7.80%	83,700
Unit 2	1959	215	8.60%	83,700
OBGS total		430	3.6%	167,400

[a] *Quarterly Fuel and Energy Report*—**2006 (CEC 2006).**

Figure K–1. General Vicinity of Ormond Beach Generating Station

2.1 COOLING WATER SYSTEM

OBGS operates one cooling water intake structure (CWIS) to provide condenser cooling water to the two generating units (Figure K–2). Once-through cooling water is combined with low-volume wastes generated by OBGS and discharged through a single submerged outfall to the Pacific Ocean, located approximately 1,790 feet offshore at a depth of 20 feet. Surface water withdrawals and discharges are regulated by National Pollutant Discharge Eliminations System (NPDES) Permit CA0001198, as implemented by Los Angeles Regional Water Quality Control Board (LARWQCB) Order 01-092.[1]

Cooling water is obtained from the Pacific Ocean through a submerged intake conduit terminating 1,950 feet offshore at a depth of approximately 35 feet. The conduit's submerged end is fitted with a velocity cap to minimize the entrainment of motile fish into the system by converting the vertical flow to a lateral flow, thus triggering a flight response from fish.

The onshore portion of the CWIS comprises four screen bays, each approximately 11 feet wide. Each bay is fitted with a vertical traveling screen with 5/8-inch mesh panels. Screens rotate periodically for cleaning based on a pressure differential between the screens' upstream and downstream faces. A high-pressure spray removes any debris or fish that have become impinged on the screen face. Captured debris is collected in a dumpster for disposal in a landfill. Downstream of each screen is a circulating water pump rated at 119,000 gallons per minute (gpm), for a total facility capacity of 476,000 gpm, or 685 million gallons per day (mgd) (Reliant Energy 2005).

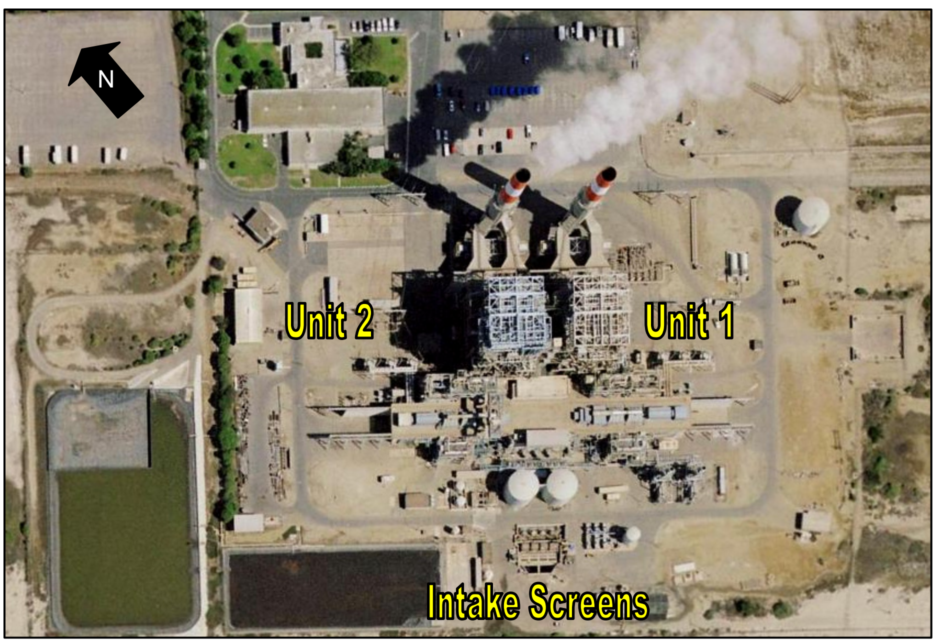

Figure K–2. Site View

[1] LARWQCB Order 01-092 expired on May 10, 2006, but has been administratively extended pending adoption of a renewed order.

At maximum capacity, OBGS maintains a total pumping capacity rated at 685 mgd, with a condenser flow rating of 654 mgd. On an annual basis, OBGS withdraws substantially less than its design capacity due to its low generating capacity utilization (3.6 percent for 2006). When in operation and generating the maximum load, OBGS can be expected to withdraw water from the Pacific Ocean at a rate approaching its maximum capacity.

2.2 SECTION 316(B) PERMIT COMPLIANCE

The CWIS currently in operation at OBGS uses a velocity cap to reduce the entrainment of motile fish through the system, although it is commonly thought of as an impingement-reduction technology because it targets larger organisms. Velocity caps have been shown to reduce impingement rates when compared with a shoreline intake structure. Likewise, the location of the intake structure in a deep, offshore setting may contribute to lower rates of entrainment when compared with a shoreline intake if the near-shore environment is more biologically productive. This study did not evaluate the effectiveness of either measure.

LARWQCB Order 01-092, adopted in 2001, states that "the design, construction and operation of the intake structure [at OBGS] represents Best Available Technology (BAT) [*sic*] as required by Section 316(b) of the Clean Water Act" (LARWQCB 2001, Finding 13). The order does not contain any numeric or narrative limitations regarding impingement or entrainment resulting from CWIS operation, but does require semiannual monitoring of impingement at each intake structure (coinciding with scheduled heat treatments). Based on the record available for review, OBGS has been compliant with this permit requirement.

The LARWQCB has notified OBGS of its intent to revisit requirements under CWA Section 316(b), including a determination of best technology available (BTA) for minimization of adverse environmental impact, during the current permit reissuance process. A final decision regarding any Section 316(b)–related requirements has not been made as of this study's publication.

3.0 WET COOLING SYSTEM RETROFIT

3.1 OVERVIEW

This study evaluates saltwater cooling towers as a retrofit option at OBGS, with the current source water (Pacific Ocean) continuing to provide makeup water to the facility. Converting the existing once-through cooling system to wet cooling towers will reduce the facility's current intake capacity by approximately 93 percent; rates of impingement and entrainment will decline by a similar proportion. Use of reclaimed water was considered for OBGS but not analyzed in detail because the available volume cannot serve as a replacement for once-through cooling water. The proximity of available sources, however, may make reclaimed water an attractive alternative as makeup water for a wet cooling tower system when considering additional benefits its use may provide, such as avoidance of conflicts with effluent limitations or air emission standards.

The wet cooling towers' configuration—their size, arrangement, and location—was based on best professional judgment (BPJ) using the criteria outlined in Chapter 5 and designed to meet the performance benchmarks in the most cost-effective manner. Information not available to this study that offers a more complete facility characterization may lead to different conclusions regarding the cooling towers' physical configuration.

This study developed a conceptual design of wet cooling towers sufficient to meet each active generating unit's cooling demand at its rated output during peak climate conditions. Cost estimates are based on vendor quotes developed using the available information and the various design constraints identified at OBGS.

The overall practicality of retrofitting both units at OBGS will require an evaluation of factors outside the scope of this study, such as each unit's age and efficiency and its role in the overall reliability of electricity production and transmission in California, particularly the Los Angeles Region.

3.2 DESIGN BASIS

3.2.1 CONDENSER SPECIFICATIONS

For this study, the wet cooling tower conceptual design selected for OBGS is based on the assumption that the condenser flow rate and thermal load to each will remain unchanged from the current system. Although no provision is included to re-optimize the condenser performance for service with a cooling tower, some modifications to the condenser (tube sheet and water box reinforcement) may be necessary to handle the increased water pressures that will result from the increased total pump head required to raise water to the cooling tower riser elevation. [2]

[2] In this context, re-optimization refers to a comprehensive condenser overhaul that reduces thermal efficiency losses associated with a wet cooling tower's higher circulating water temperatures. Modifications discussed in this study are generally limited to reinforcement measures that enable the condenser to withstand increased water pressures.

The practicality and difficulty of these modifications are dependent each unit's age and configuration but are assumed to be feasible at OBGS. Condenser water boxes for both units are located at grade level and appear to be readily accessible. Additional costs for condenser modifications are included in the discussion of capital expenditures (Section 4.3).

Information provided by OBGS was largely used as the basis for the cooling tower design. In some cases, the data were incomplete or conflicted with values obtained from other sources. Where possible, questionable values were verified or corrected using other known information about the condenser.

Parameters used in the development of the cooling tower design are summarized in Table K–5.

Table K–5. Condenser Design Specifications

	Unit 1	Unit 2
Thermal load (MMBTU/hr)	3371.67	3371.67
Surface area (ft^2)	210,000	210,000
Condenser flow rate (gpm)	227,000	227,000
Tube material	Cu-Ni (90-10)	Cu-Ni (90-10)
Heat transfer coefficient (BTU/hr•ft^2•°F)	521	521
Cleanliness factor	0.85	0.85
Inlet temperature (°F)	62	62
Temperature rise (°F)	29.72	29.72
Steam condensate temperature (°F)	110.9	110.9
Turbine exhaust pressure (in. HgA)	2.67	2.67

3.2.2 AMBIENT ENVIRONMENTAL CONDITIONS

OBGS is located in Ventura County adjacent to Ormond Beach and the Pacific Ocean approximately 2.5 miles southeast of Port Hueneme. Cooling water is from the Pacific Ocean via a submerged conduit extending offshore. Inlet temperature data were not available from OBGS. Instead, surface water temperatures used in this analysis were based on monthly average coastal water temperatures as reported in the NOAA *Coastal Water Temperature Guide, Ventura and Port Hueneme* (NOAA 2007).

The wet bulb temperature used in the development of the overall cooling tower design was obtained from American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) publications. Data for coastal Ventura County indicate a 1 percent ambient wet bulb temperature of 66° F (ASHRAE 2006). An approach temperature of 12° F was selected based on the site configuration and vendor input. At the design wet bulb and approach temperatures, the cooling towers will yield "cold" water at a temperature of 78° F.

Monthly maximum wet bulb temperatures used in the development of energy penalty estimates in Section 4.6 were calculated using data obtained from California Irrigation Management Information System (CIMIS) Monitoring Station 156 in Oxnard (CIMIS 2006). Climate data used in this analysis are summarized in Table K–6.

Table K–6. Surface Water and Ambient Wet Bulb Temperatures

	Surface (°F)	Ambient wet bulb (°F)
January	57.2	57.9
February	58.3	58.3
March	59.5	59.7
April	61.1	60.7
May	61.4	62.5
June	62.6	65.3
July	64.1	66.1
August	63.9	66.3
September	62.0	64.7
October	60.9	62.4
November	59.3	61.3
December	58.7	58.9

3.2.3 LOCAL USE RESTRICTIONS

3.2.3.1 NOISE

Industrial development in the vicinity of OBGS is covered by the City of Oxnard General Plan and the City of Oxnard Land Use Plan (LUP). General Plan Section 10 (Noise Element) outlines the broad policy related to noise impacts within the city's different development zones. The plan outlines narrative criteria to be used as a guide for future development, but does not identify numeric noise limits for new construction (Oxnard 2006). Land use within the general vicinity of OBGS is primarily agricultural, although recent residential developments have encroached upon the area. Noise associated with the cooling towers is not expected to have any discernible impact upon these areas. The proximity to state beaches, however, may conflict with recreational standards set forth in the Ventura County Local Coastal Plan, but again, no numeric limits are specified.

In lieu of specific noise criteria, this study used an ambient noise limit of 65 dBA at a distance of 1,200 feet in selecting the design elements of the wet tower installation. Accordingly, the final design selected for OBGS does not require any measures that specifically address noise, such as low-noise fans or barrier walls.

3.2.3.2 BUILDING HEIGHT

OBGS is located within the coastal energy facilities subzone (EC) of the City of Oxnard LUP, which encourages the expansion of energy-related activities within the existing site consistent with other plan provisions. The LUP does not establish specific criteria for building height and instead relies on conditional use permitting that evaluates each project independently. Given the height of existing structures at OBGS, this study selected a height restriction of 50 feet above grade level. The height of the wet cooling towers designed for OBGS, from grade level to the top of the fan deck, is 49 feet.

3.2.3.3 PLUME ABATEMENT

Local zoning ordinances do not contain any specific criteria for addressing any impact associated with a wet cooling tower plume. The proximity of OBGS to the Point Mugu Naval Air Station, however, may necessitate incorporating plume abatement measures into the final design. As shown in Figure K–1, OBGS is located approximately 2.5 miles northwest of the air station. With prevailing winds from the west, a persistent plume has the potential to interfere with flight operations at the air station, but specific requirements or limits could not be identified.

Likewise, community standards for assessing the visual impact associated with a cooling tower plume cannot be determined within the scope of this study. Agricultural uses predominate in the general vicinity of OBGS, with few residential areas located in the area. The proximity of OBGS to coastal recreational areas and sensitive wetlands, and the potential visual impact on those resources, may require plume abatement measures. CEC siting guidelines and Coastal Act provisions evaluate the total size and persistence of a visual plume with respect to aesthetic standards for coastal resources; significant visual changes resulting from a persistent plume would likely be subject to additional controls.

Plume abatement towers were initially selected for evaluation at OBGS due to the likelihood they would be required to eliminate potential impact on operations at the Point Mugu Naval Air Station. Further investigation and consultation with cooling tower vendors, however, indicated that plume-abated towers could not be located at the site given the constraints on available space and building height that would preclude their construction. Accordingly, all towers evaluated for OBGS are of a conventional design.

3.2.3.4 DRIFT AND PARTICULATE EMISSIONS

Drift elimination measures that are considered best available control technology (BACT) are required for all cooling towers evaluated in this study, regardless of their location. State-of-the-art drift eliminators are included for each cooling tower cell at OBGS, with an accepted efficiency of 0.0005 percent. Because cooling tower PM_{10} emissions are a function of the drift rate, drift eliminators are also considered BACT for PM_{10} emissions from wet cooling towers. This efficiency can be verified by a proper in situ test, which accounts for site-specific climate, water, and operating conditions. Testing based on the Cooling Tower Institute's Isokinetic Drift Test Code is required at initial start-up on only one representative cell of each tower for an approximate cost of $60,000 per test, or approximately $240,000 for both cooling towers at OBGS (CTI 1994). This cost is not itemized in the final analysis and is instead included as part of the indirect cost estimate (Section 4.3).

3.2.3.5 FACILITY CONFIGURATION AND AREA CONSTRAINTS

The existing site's configuration and the total available area present significant challenges to identifying sufficient space on which to place wet cooling towers. Because the maximum combined condenser thermal load from the generating units (6,742 MMBTU/hr) is relatively large, the cooling towers will have to incorporate a large number of cells to achieve the desired level of cooling. Prior to the acquisition of OBGS by Reliant Energy, Inc., the original site included a large area owned by SCE, which contained several large fuel oil tanks (since removed). In June 2002 following negotiations with SCE, the State Coastal Conservancy acquired 256 acres of the former tank farm site in support of efforts to protect wetlands and related habitats in the vicinity of Ormond Beach (SCC 2003). Figure K–3 outlines the current and former property boundaries, with the fuel tank footprints still clearly visible.

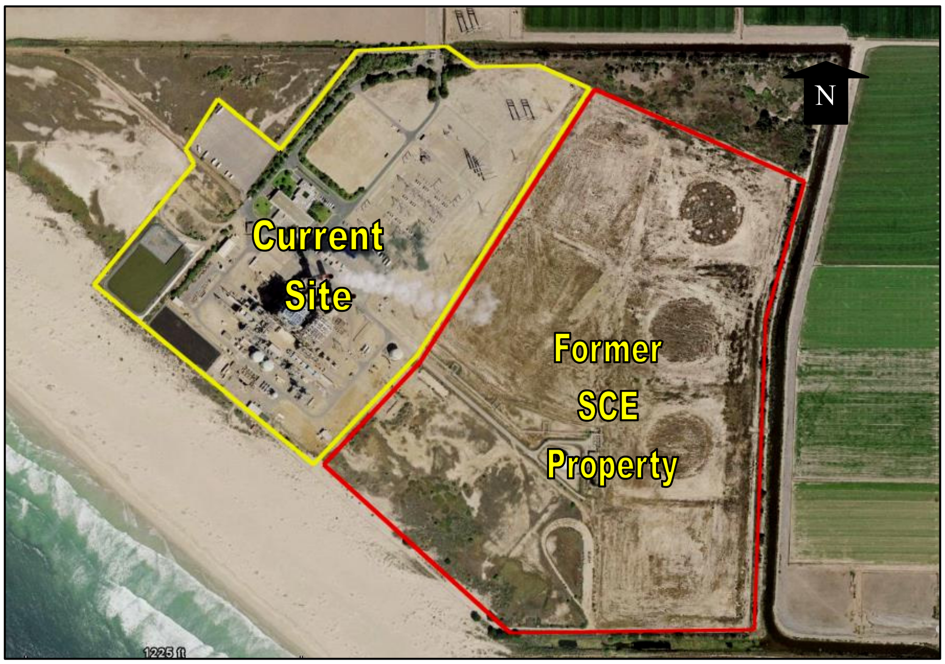

Figure K–3. Current and Former Site Boundaries

The remaining areas at OBGS that can accommodate wet cooling towers are shown in Figure K–4. Placement of towers in Area 1 is impractical due to the proximity to the generating units and the prevailing wind direction, which places the towers immediately upwind of the power block at a distance of less than 150 feet. Drift from wet cooling towers in this location would likely settle on sensitive equipment and pose significant maintenance challenges from salt corrosion.

Use of Area 2, located north of the units, would minimize this effect on the power block but create similar impacts on the switchyard and transmission lines that extend northward. Ultimately, while neither area is ideal, Area 2 was selected as the most practical location for wet cooling tower. Drift deposition and salt corrosion on switchyard equipment and transmission lines would likely be a significant issue and, if wet cooling towers were constructed here, the equipment and lines might require relocation or replacement with gas insulated switchgear (GIS). Use of reclaimed water might mitigate these effects (see Section 3.4.4).

The space limitations at OBGS are more restrictive when attempting to design plume-abated towers for the site. If configured in an inline arrangement, these towers would be nearly twice the length of a conventional tower design. Consultations with cooling tower vendors indicated a round plume-abated tower might be feasible, but would have to be very tall (70 to 80 feet). This would likely conflict with building height restrictions in the coastal zone for Ventura County and might present design challenges to comply with Zone 4 seismic construction requirements.

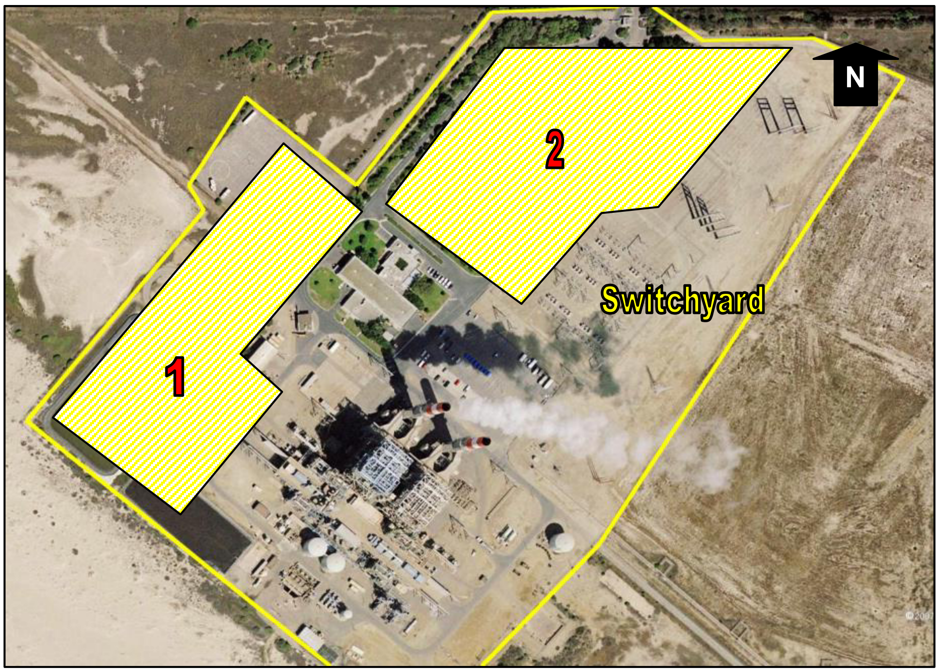

Figure K–4. Cooling Tower Siting Areas

3.3 CONCEPTUAL DESIGN

Based on the design constraints discussed above two wet cooling tower complexes, each consisting of two towers, were selected to replace the current once-through cooling system at OBGS, for a total of four towers. Each tower complex will operate independently and be dedicated to one unit. Each tower is configured in a multicell, inline arrangement.

3.3.1 SIZE

Each tower is constructed over a concrete collection basin 4 feet deep. The basin is larger than the tower structure's footprint, extending an additional 2 feet in each direction. The concrete used for construction is suitable for saltwater applications. The principal tower material is fiberglass reinforced plastic (FRP), with stainless steel fittings. These materials are more resistant to the higher corrosive effects of saltwater.

The size of each tower is primarily based on the thermal load rejected to the tower by the surface condenser and a 12° F approach to the ambient wet bulb temperature. Flow rates through each condenser remain unchanged.

General characteristics of the wet cooling towers selected for OBGS are summarized in Table K–7.

Table K–7. Wet Cooling Tower Design

	Tower Complex 1 (Unit 1)	Tower Complex 2 (Unit 2)
Thermal load (MMBTU/hr)	3371.67	3371.67
Circulating flow (gpm)	227,000	227,000
Number of cells	18	18
Tower type	Mechanical draft	Mechanical draft
Flow orientation	Counterflow	Counterflow
Fill type	Modular splash	Modular splash
Arrangement	Inline	Inline
Primary tower material	FRP	FRP
Tower dimensions (l x w x h) (ft) [a]	486 x 54 x 49	486 x 54 x 49
Tower footprint with basin (l x w) (ft) [a]	490 x 58	490 x 58

[a] Two individual towers with these dimensions form each cooling tower complex.

3.3.2 LOCATION

The initial site selection for each tower was based on the desire to locate each tower as close as possible to its respective generating unit to minimize the supply and return pipe distances and any increases in total pump head and brake horsepower. Tower Complex 1, serving Unit 1, is located at an approximate distance of 550 feet. Tower Complex 2, serving Unit 2, is located at approximate distance of 800 feet. (Figure K–5).

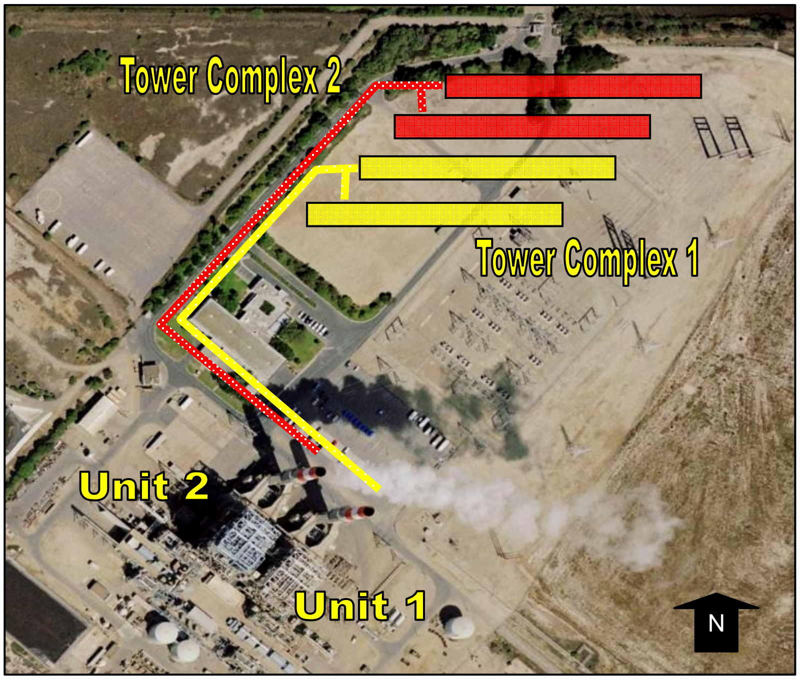

Figure K-5. Cooling Tower Locations

3.3.3 PIPING

The main supply and return pipelines to and from both towers will be located underground and made of prestressed concrete cylinder pipe (PCCP) suitable for saltwater applications. These pipes range in size from 72 to 96 inches in diameter. Pipes connecting the condensers to the supply and return lines are made of FRP and placed above ground on pipe racks. Above-ground placement avoids the potential disruption that may be caused by excavation in and around the power block. The condensers at OBGS are located at grade level, enabling a relatively straightforward connection.

All riser piping (extending from the foot of the tower to the level of water distribution) is constructed of FRP.

Potential interference with underground obstacles and infrastructure is a concern, particularly at existing sites that are several decades old and have been substantially modified or rebuilt in the interim. Avoidance of these obstacles is considered to the degree practical in this study. Associated costs are included in the contingency estimate and are generally higher than similar estimates for new facilities (Section 4.3).

Appendix B details the total quantity of each pipe size and type for OBGS.

3.3.4 FANS AND PUMPS

Each tower cell uses an independent single-speed fan. The fan size and motor power are the same for each cell in each tower.

This analysis includes new pumps to circulate water between the condensers and cooling towers. Pumps are sized according to the flow rate for each tower, the relative distance between the towers and condensers, and the total head required to deliver water to the top of each cooling tower riser. A separate, multilevel pump house is constructed for each tower and sized to accommodate the motor control centers (MCCs) and appropriate electrical switchgear. The electrical installation includes all necessary transformers, cabling, cable trays, lighting, and lightning protection. A 50-ton overhead crane is also included to allow for pump servicing.

Fan and pump characteristics associated with wet cooling towers at OBGS are summarized in Table K–8. The net electrical demand of fans and new pumps is discussed further as part of the energy penalty analysis in Section 4.6.

Table K–8. Cooling Tower Fans and Pumps

		Tower Complex 1 (Unit 1)	Tower Complex 2 (Unit 2)
Fans	Number	18	18
	Type	Single speed	Single speed
	Efficiency	0.95	0.95
	Motor power (hp)	263	263
Pumps	Number	4	4
	Type	50% recirculating Mixed flow Suspended bowl Vertical	50% recirculating Mixed flow Suspended bowl Vertical
	Efficiency	0.88	0.88
	Motor power (hp)	1,386	1,386

3.4 ENVIRONMENTAL EFFECTS

Converting the existing once-through cooling system at OBGS to wet cooling towers will significantly reduce the intake of seawater the Pacific Ocean and will presumably reduce impingement and entrainment by a similar proportion. Because closed-cycle systems will almost always result in condenser cooling water temperatures higher than those found in a comparable once-through system, wet towers will increase the operating heat rates at both of OBGS's steam units, thereby decreasing the facility's overall efficiency. Additional power will also be consumed by the tower fans and circulating pumps.

Depending on how OBGS chooses to address this change in efficiency, total stack emissions may increase for pollutants such as $PM_{10,}$ $SO_{x,}$ and NO_x, and may require additional control measures (e.g., electrostatic precipitation, flue gas desulfurization, and selective catalytic reduction) or the purchase of emission credits to meet air quality regulations. The availability of emission reduction credits (ERCs) and their associated cost was not evaluated as part of this study. Both factors, however, may limit the air emission compliance options available to OBGS.

No control measures are currently available for CO_2 emissions, which will increase, on a per-kWh basis, by the same proportion as any change in the heat rate. The towers themselves will constitute an additional source of PM_{10} emissions, the annual mass of which will largely depend on the capacity utilization rate for the generating units served by each tower.

If OBGS retains its NPDES permit to discharge wastewater to the Pacific Ocean with a wet cooling tower system, it may have to address revised effluent limitations resulting from the substantial change in the discharge quantity and characteristics. Thermal impacts from the current once-through system, if any, will be minimized with a wet cooling system.

3.4.1 AIR EMISSIONS

OBGS is located in the South Central Coast air basin. Air emissions are permitted by the Ventura County Air Pollution Control District (VCAPCD) (Facility ID 65).

Drift volumes are expected to be within the range of 0.5 gallons for every 100,000 gallons of circulating water in the towers. At OBGS, this corresponds to a rate of approximately 2.25 gpm based on the maximum combined flow both two towers. Agricultural operations lie within 0.25 mile to the north and 0.75 mile to the east. Given the direction of prevailing winds (from the west) some drift may carry to these areas, but the impact is not likely to be significant.

Total PM_{10} emissions from the OBGS cooling towers are a function of the number of hours in operation, the overall water quality in the tower, and the evaporation rate of drift droplets prior to deposition on the ground. Makeup water at OBGS will be obtained from the same source currently used for once-through cooling water (Pacific Ocean). At 1.5 cycles of concentration and assuming an initial total dissolved solids (TDS) value of 35 parts per thousand (ppt), the water within the cooling towers will reach a maximum TDS level of roughly 53 ppt. Any drift droplets exiting the tower will have the same TDS concentration.

The cumulative mass emission of PM_{10} from OBGS will increase as a result of the direct emissions from the cooling towers themselves. Stack emissions of PM_{10}, as well as SO_x, NO_x, and other pollutants, will increase due to the drop in fuel efficiency, although the cumulative increase will depend on actual operations and emission control technologies currently in use. Maximum drift and PM_{10} emissions from the cooling towers are summarized in Table K–9.[3]

Data summarizing the total facility emissions for these pollutants in 2005 are presented in Table K–10 (CARB 2005). In 2005, OBGS operated at an annual capacity utilization rate of 4 percent.

[3] This is a conservative estimate that assumes all dissolved solids present in drift droplets will be converted to PM_{10}. Studies suggest this may overestimate actual emission profiles for saltwater cooling towers (Chapter 4).

Using this rate, the additional PM_{10} emissions from the cooling towers would increase the facility total by approximately 10.5 tons/year, or 110 percent.[4]

Table K–9. Full Load Drift and Particulate Estimates

	PM_{10} (lbs/hr)	PM_{10} (tons/year)	Drift (gpm)	Drift (lbs/hr)
Tower Complex 1	30	131	1.14	568
Tower Complex 2	30	131	1.14	568
Total OBGS PM_{10} and drift emissions	**60**	**262**	**2.28**	**1,136**

Table K–10. 2005 Emissions of SO_x, NO_x, PM_{10}

Pollutant	Tons/year
NO_x	20.1
SO_x	1.7
PM_{10}	9.6

3.4.2 MAKEUP WATER

The volume of makeup water required by both cooling towers at OBGS is the sum of evaporative loss and the blowdown volume required to maintain the circulating water in each tower at the design TDS concentration. Drift expelled from the towers represents an insignificant volume by comparison and is accounted for by rounding up evaporative loss estimates. Makeup water volumes are based on design conditions, and may fluctuate seasonally depending on climate conditions and facility operations. Wet cooling towers will reduce once-through cooling water withdrawals from the Pacific Ocean by approximately 93 over the current design intake capacity.

Table K–11. Makeup Water Demand

	Tower circulating flow (gpm)	Evaporation (gpm)	Blowdown (gpm)	Total makeup water (gpm)
Tower Complex 1	227,000	5,400	10,800	**16,200**
Tower Complex 2	227,000	5,400	10,800	**16,200**
Total OBGS makeup water demand	**454,000**	**10,800**	**21,600**	**32,400**

One circulating water pump, rated at 119,000 gpm, which is currently used to provide once-through cooling water to the facility, will be retained in a wet cooling system to provide makeup water to each cooling tower. The retained pump's capacity exceeds the makeup demand by approximately 86,000 gpm. Any excess capacity will be routed through a bypass conduit and returned to the wet well at a point located behind the intake screens. Recirculating the excess capacity in this manner reduces additional cost that would be incurred if new pumps were required while maintaining the desired flow reduction. The intake of new water, measured at the intake screens, will be equal to the cooling towers' makeup water demand. Figure K–6 presents a schematic of this configuration.

[4] 2006 emission data are not currently available from the Air Resources Board website. For consistency, the comparative increase in PM10 emissions estimated here is based on the 2005 OBGS capacity utilization rate instead of the 2006 rate presented in Table K-4. All other calculations in this chapter use the 2006 value.

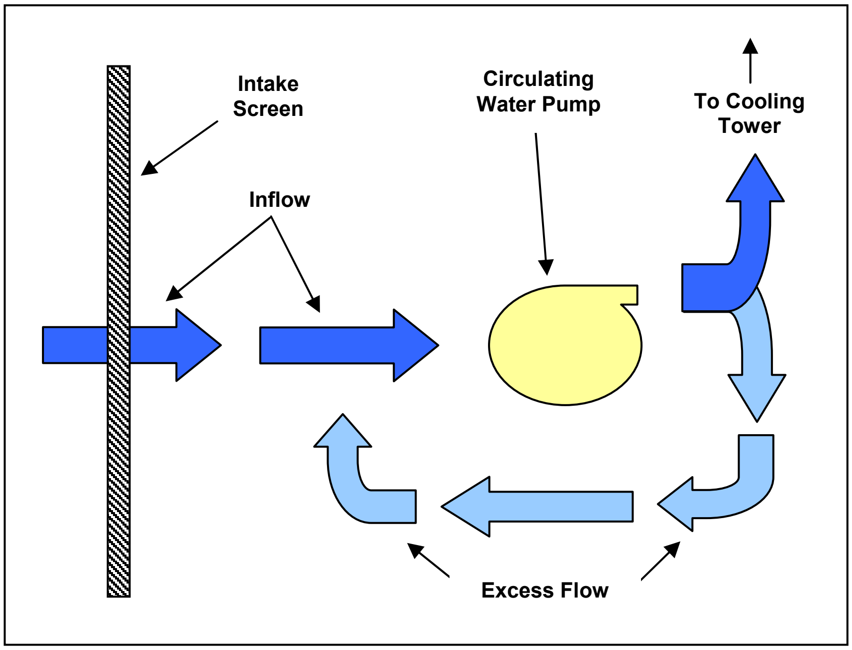

Figure K–5. Schematic of Intake Pump Configuration

The existing once-through cooling system at OBGS does not treat water withdrawn from the Pacific Ocean, with the exception of screening for debris and larger organisms and periodic chlorination to control biofouling in the condenser tubes. Heat treatments are also periodically used to control mussel growth on pipes and condenser tubes by raising the circulating water temperature to 125º F. Conversion to a wet cooling tower system will not interfere with chlorination or heat treatment operations.

Makeup water will continue to be withdrawn from the Pacific Ocean.

The wet cooling tower system proposed for OBGS includes water treatment for standard operational measures, i.e., corrosion inhibitors, biocides, and anti-scaling agents. An allowance for these additional chemical treatments is included in annual O&M costs. It is assumed that the current once-through cooling water quality will be acceptable for use in a seawater cooling tower (with continued screening and chlorination) and will not require any pretreatment to enable its use.

3.4.3 NPDES PERMIT COMPLIANCE

At maximum operation, wet cooling towers at OBGS will result in an effluent discharge of 31 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, regeneration wastes, and cleaning wastes. These low volume wastes may add an additional

0.75 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, OBGS will be required to modify its existing individual wastewater discharge (NPDES) permit.

Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0001198, as implemented by LARWQCB Order 01-092. All wastewaters are discharged to the Pacific Ocean through a submerged conduit extending approximately 1,790 feet offshore. The existing order contains effluent limitations based on the 1997 Ocean Plan and 1972 Thermal Plan.

OBGS will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities (40 CFR 423.13(d)(1)). These ELGs set numeric limitations for chromium and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity). Because ELGs are technology-based limitations, mixing zones or dilution factors are not applicable when determining compliance; limits must be met at the point of discharge from the cooling tower prior to commingling with any other waste stream. ELGs for cooling tower blowdown target priority pollutants that are contributed by maintenance chemicals and do not apply when limits may be exceeded as a result of background concentrations or other sources. Further discussion can be found in Chapter 4, Section 3.6.

Conversion to wet cooling towers will alter the volume and composition of a facility's wastewater discharge because wet towers concentrate certain pollutants in the effluent waste stream. The cooling towers designed for OBGS operate at 1.5 cycles of concentration, i.e., the blowdown discharge will contain a dissolved solids concentration 50 percent higher than the makeup water.

Changes to discharge composition may affect compliance with water quality objectives included in the Ocean Plan. If compliance with these objectives becomes problematic, alternative treatment or discharge methods may be necessary. Compliance may be achieved by altering the discharge configuration in such a way as to increase dilution (e.g., diffuser ports), or by seeking a mixing zone and dilution credits as permissible under the Ocean Plan. Alternately, some low volume waste streams (e.g., boiler blowdown, laboratory drains) may be diverted, with necessary permits, for treatment at a POTW.

If more pollutant-specific treatment methods, such as filtration or precipitation technologies, become necessary to meet WQBELs, the initial capital cost may range from \$2 to \$5.50 per 1,000 gallons of treatment capacity, with annual costs of approximately \$0.5 per gallon of capacity, depending on the method of treatment (FRTR 2002). Hazardous material disposal fees and permits would further increase costs.

This evaluation did not include alternative discharge or effluent treatment measures in the conceptual design because the variables used to determine final WQBELs, which would be used to determine the type and scope of the desired compliance method, cannot be quantified here. Likewise, the final cost evaluation (Section 4.0) does not include any allowance for these possibilities.

Use of reclaimed water as the cooling tower makeup source has the potential to reduce or eliminate conflicts with effluent limitations (see Section 3.4.4).

Thermal discharge standards are based on narrative criteria established for coastal discharges under the Thermal Plan, which requires that existing discharges of elevated-temperature wastes comply with effluent limitations necessary to assure the protection of designated beneficial uses. The LARWQCB has implemented this provision by establishing a maximum discharge temperature of 105º F during normal operations in Order 01-092 (LARWQCB 2001). Information available for review indicates OBGS has consistently been able to comply with this requirement. Because cooling tower blowdown will be taken from the "cold" side of the tower, conversion to a wet cooling system will significantly reduce the discharge temperature (to less than 80º F) and the size of any related thermal plume in the receiving water.

3.4.4 RECLAIMED WATER

Reclaimed or alternative water sources used in conjunction with wet cooling towers could eliminate all surface water withdrawals at OBGS. Doing so would completely eliminate impingement and entrainment concerns, and might enable the facility to avoid possible effluent quality and permit compliance issues, depending on the quality of reclaimed water available for use. In addition, wet cooling towers using reclaimed water would be expected to have lower PM_{10} emissions due to the lower TDS levels. The California State Water Resources Control Board (SWRCB), in 1975, issued a policy statement requiring the consideration of alternative cooling methods in new power plants, including reclaimed water, over the use of freshwater (SWRCB 1975). There is no similar policy regarding marine waters, but the clear preference of state agencies is to encourage alternative cooling methods, including reclaimed water, wherever possible.

The present volume of available reclaimed water within a 15-mile radius of OBGS (53 mgd) does not meet the current once-through cooling demand; thus, reclaimed water is only applicable as a source of makeup water for a wet cooling tower system. This study did not pursue a detailed investigation of reclaimed water's use because the conversion of OBGS's once-through cooling system to saltwater cooling towers meets the performance benchmarks for impingement and entrainment impact reductions discussed in the 2006 California Ocean Protection Council (OPC) Resolution on Once-Through Cooling Water (see Chapter 1).

To be acceptable for use as makeup water in cooling towers, reclaimed water must meet tertiary treatment and disinfection standards under California Code of Regulations (CCR) Title 22. If the reclaimed water is not treated to the required levels, OBGS would be required to arrange for sufficient treatment, either onsite or at the source facility, prior to its use in the cooling towers.

An additional consideration for reclaimed water is the presence of any ammonia or ammonia-forming compounds in the reclaimed water. All the condenser tubes at OBGS contain copper alloys (copper nickel [90-10]) and can experience stress-corrosion cracking as a result of the interaction between copper and ammonia. Treatment for ammonia may include adding ferrous sulfate as a corrosion inhibitor or require ammonia-stripping towers to pretreat reclaimed water prior to use in the cooling towers (EPA 2001).

Five publicly owned treatment works (POTWs) were identified within a 15-mile radius of OBGS, with a combined discharge capacity of 53 mgd. Figure K–7 shows the relative locations of these facilities to OBGS.

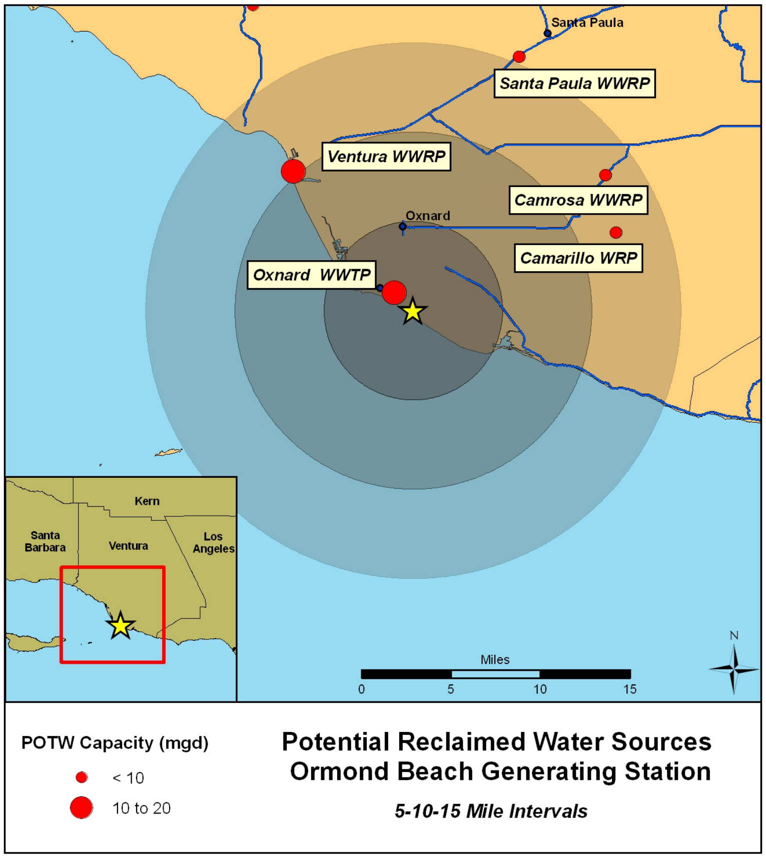

Figure K–6. Reclaimed Water Sources

- *City of Ventura Water Reclamation Facility (VWRF)—Ventura*
  Discharge volume: 14 mgd
  Distance: 10 miles NW
  Treatment level: Tertiary

  All wastewater at VWRF is treated to tertiary standards. Approximately 1.0 mgd is currently used for irrigation purposes in the vicinity. Facility staff indicated that demand is increasing as the area is developed and future uses may limit any capacity available to OBGS as a makeup water source. Based on the current available capacity, however, VWRF could provide most of the makeup water (13–15 mgd) for freshwater cooling towers at OBGS.

- *City of Oxnard Wastewater Treatment Plant—Oxnard*
  Discharge volume: 31 mgd
  Distance: 1.5 miles SE
  Treatment level: Secondary

  No information available. The existing capacity is sufficient to supply enough makeup water (13–15 mgd) for freshwater cooling towers at OBGS, although arrangements for tertiary treatment would have to be made prior to its use.

Three other wastewater treatment plants—Camarillo, Camrosa, and Santa Paula—lie within 10–5 miles of OBGS. The combined capacity of these facilities (approximately 8 mgd) is less than the makeup demand required in freshwater towers at OBGS. If reclaimed water sources are pursued, the most practical options are the Oxnard and Ventura facilities.

The costs associated with installing transmission pipelines (excavation/drilling, material, labor), in addition to design and permitting costs, are difficult to quantify in the absence of a detailed analysis of various site-specific parameters that will influence the final configuration. The nearest facility with sufficient capacity to satisfy OBGS's freshwater tower makeup demand (5–8 mgd) is located approximately 2.5 miles from the site (Ventura WRF). The area between the two facilities is not heavily developed. Installing a transmission pipeline would not face any significant obstacles in terms of infrastructure or right of way.

Based on data compiled for this study and others, the estimated installed cost of a 36-inch prestressed concrete cylinder pipe, sufficient to provide 15 mgd to OBGS, is $320 per linear foot, or approximately $1.7 million per mile. Additional considerations, such as pump capacity and any required treatment, would increase the total cost.

Regulatory concerns beyond the scope of this investigation, however, may make reclaimed water (as a makeup water source) comparable or preferable to saltwater from the Pacific Ocean. Reclaimed water may enable OBGS to eliminate potential conflicts with water discharge limitations or reduce PM10 emissions from the cooling tower, which is a concern given the South Coast air basin's current nonattainment status.

Salt deposition, and the adverse impacts it can have on sensitive equipment, can be mitigated by using freshwater (reclaimed water) in the towers instead of saltwater from the Pacific Ocean. Although reclaimed water salinity levels would be substantially lower and are unlikely to cause the same, the switchyard and transmission lines would still require some measure of upgrade or protection because of their proximity immediately downwind of the towers' plume. Plume-abated towers could lessen this effect but cannot be configured within the site's current boundaries (Section 3.2.3).

At any facility where wet cooling towers are a feasible alternative, reclaimed water may be used as a makeup water source. The practicality of its use, however, depends on the overall cost, availability, and additional environmental benefit that may occur.

3.4.5 THERMAL EFFICIENCY

Wet cooling towers at OBGS will increase the condenser inlet water temperature by a range of 14 to 16° F above the surface water temperature, depending on the ambient wet bulb temperature at the time. The generating units at OBGS are designed to operate at the conditions described in Table K–12. The resulting monthly difference between once-through and wet cooling tower condenser inlet temperatures is described in Figure K–8.

Table K–12. Design Thermal Conditions

	Unit 1	Unit 2
Design backpressure (in. HgA) (high pressure zone)	2.67	2.67
Design water temperature (°F)	62	62
Turbine inlet temp (°F)	1,000	1,000
Turbine inlet pressure (psia)	3,500	3,500
Full load heat rate (BTU/kWh) [a]	9,409	9,200

[a] CEC 2002.

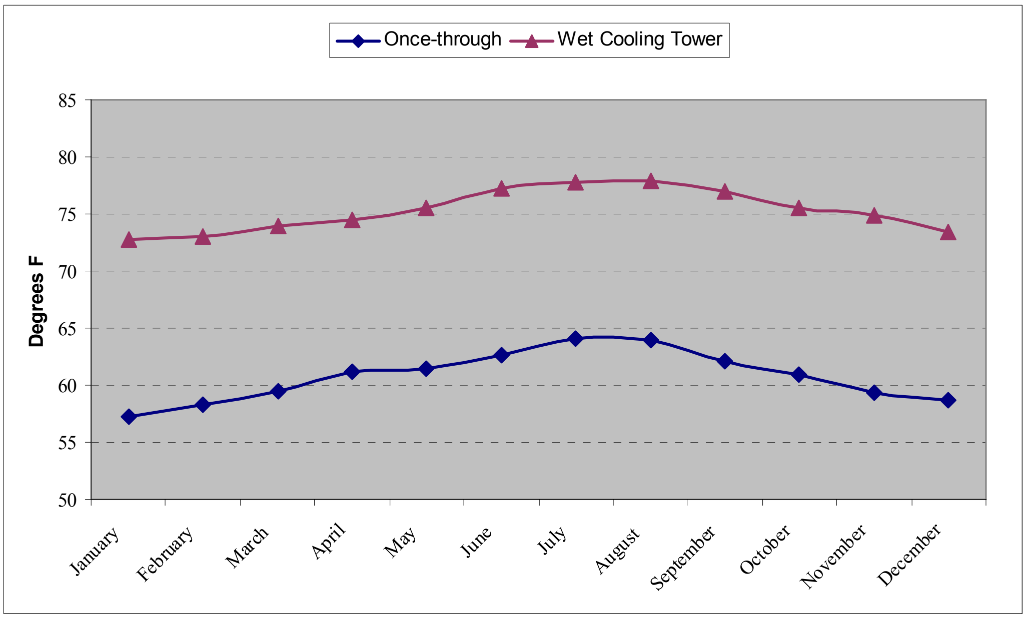

Figure K–7. Condenser Inlet Temperatures

Backpressures for the once-through and wet cooling tower configurations were calculated for each month using the design criteria described in the sections above and ambient climate data. In general, backpressures associated with the wet cooling tower were elevated by 1.0 to 1.15 inches HgA compared with the current once-through system (Figure K–9 and Figure K–11).

Heat rate adjustments were calculated by comparing the theoretical change in available energy that occurs at different turbine exhaust backpressures, assuming the thermal load and turbine inlet pressure remain constant, i.e., at the full load rating. The relative change at different backpressures was compared with the value calculated for the design conditions (i.e., at design turbine inlet and exhaust backpressures) and plotted as a percentage of the full load operating heat rate to develop estimated correction curves (Figure K–10 and Figure K–10).

The difference between the estimated once-through and closed-cycle heat rates for each month represents the approximate heat rate increase that would be expected when converting to wet cooling towers.

Table K–13 summarizes the annual average heat rate increase for each unit as well as the increase associated with the peak demand period of July-August-September. Monthly values were used to calculate the monetized value of these heat rate changes (Section 4.6). Month-by-month calculations are presented in Appendix A.

Table K–13. Summary of Estimated Heat Rate Increases

	Unit 1	Unit 2
Peak (July-August-September)	1.90%	1.90%
Annual average	1.69%	1.69%

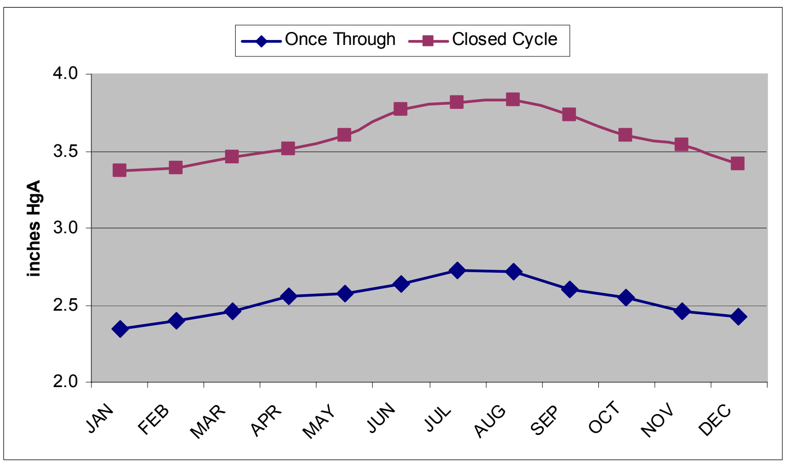

Figure K–8. Estimated Backpressures (Unit 1)

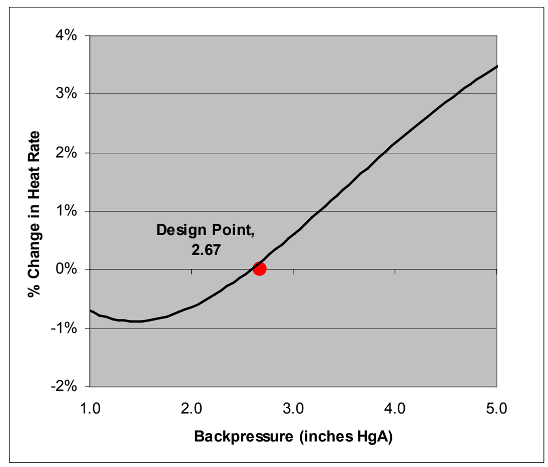

Figure K–9. Estimated Heat Rate Correction (Unit 1)

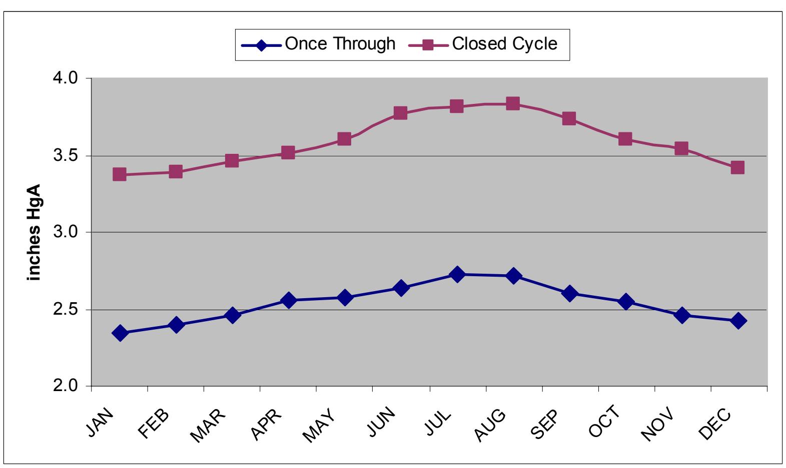

Figure K–10. Estimated Backpressures (Unit 2)

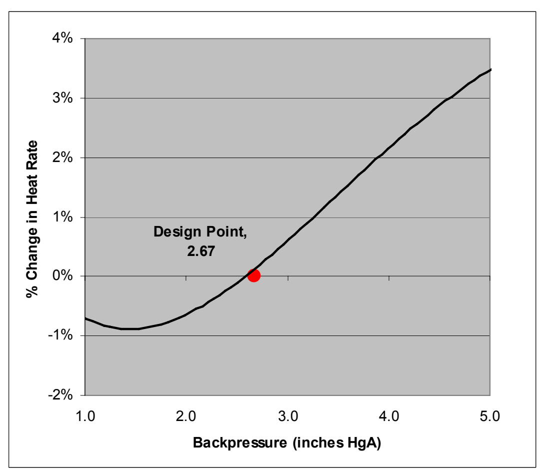

Figure K–11. Estimated Heat Rate Correction (Unit 2)

4.0 RETROFIT COST ANALYSIS

The wet cooling system retrofit estimate for OBGS is based on incorporating conventional wet cooling towers as a replacement for the existing once-through system for each unit. Standard cost elements for this project include the following:

- Direct (cooling tower installation, civil/structural, mechanical, piping, electrical, and demolition)
- Indirect (smaller project costs not itemized)
- Contingency (allowance for unknown project variables)
- Revenue loss from shutdown (net loss in revenue during construction phase)
- Operations and maintenance (non–energy related cooling tower operations)
- Energy penalty (includes increased parasitic use from fans and pumps as well as decreased thermal efficiency)

The cost analysis does not include allowances for elements that are not quantified in this study, such as land acquisition, effluent treatment, or air emission reduction credits. The methodology used to develop cost estimates is discussed in Chapter 5.

4.1 COOLING TOWER INSTALLATION

The preferred design for OBGS—plume-abated towers—could not be configured at the site. Conventional cooling towers were evaluated instead.

In general, the evaluated cooling tower configuration conforms to a typical design; no significant variations from a conventional arrangement were required. The principal difference is the need to construct two cooling towers for each unit, which marginally increases costs.

Table K–14 summarizes the design-and-build cost estimate for each tower developed by vendors, inclusive of all labor and management required for their installation.

Table K–14. Wet Cooling Tower Design-and-Build Cost Estimate

	Unit 1	Unit 2	OBGS total
Number of cells	18	18	**36**
Cost/cell ($)	594,444	594,444	**594,444**
Total OBGS D&B cost ($)	**10,700,000**	**10,700,000**	**21,400,000**

4.2 OTHER DIRECT COSTS

A significant portion of wet cooling tower installation costs result from the various support structures, materials, equipment and labor necessary to prepare the cooling tower site and connect the towers to the condenser. At OBGS, these costs comprise approximately 55 percent of the initial capital cost. Line item costs are detailed in Appendix B.

Deviations from or additions to the general cost elements discussed in Chapter 5 are discussed below. Other direct costs (non–cooling tower) are summarized in Table K–15.

- *Civil, Structural, and Piping*
  The OBGS site configuration allows each tower complex to be located within relative proximity to the generating unit it services. Increased costs are incurred for additional materials and labor that result from dividing the cooling tower for each unit into two separate towers.
- *Mechanical and Electrical*
  Initial capital costs in this category reflect the new pumps (four total) to circulate cooling water between the towers and condensers. Overall pump capacity is larger than an average arrangement as a result of dividing the cooling tower for each unit into two separate towers. No new pumps are required to provide makeup water from the Pacific Ocean. Electrical costs are based on the battery limit after the main feeder breakers.
- *Demolition*
  No demolition costs are required. Any demolition costs for minor projects are covered by the indirect cost estimate.

Table K–15. Summary of Other Direct Costs

	Equipment ($)	Bulk material ($)	Labor ($)	OBGS total ($)
Civil/structural/piping	6,300,000	20,900,000	15,100,000	**42,300,000**
Mechanical	10,100,000	0	800,000	**10,900,000**
Electrical	1,600,000	3,100,000	2,200,000	**6,900,000**
Demolition	0	0	0	**0**
Total OBGS other direct costs	**18,000,000**	**24,000,000**	**18,100,000**	**60,100,000**

4.3 INDIRECT AND CONTINGENCY

Indirect costs are calculated as 25 percent of all direct costs (civil/structural, mechanical, electrical, demolition, and cooling towers).

An additional allowance is included for condenser water box and tube sheet reinforcement to withstand the increased pressures associated with a recirculating system. Each condenser may require reinforcement of the tube sheet bracing with 6-inch x 1-inch steel, and water box reinforcement/replacement with 5/8-inch carbon steel. Based on the estimates outlined in Chapter 5, a conservative estimate of 5 percent of all direct costs is included to account for possible condenser modifications.

The contingency cost is calculated as 25 percent of the sum of all direct and indirect costs, including condenser reinforcement. At OBGS, potential costs in this category include relocating or demolishing small buildings and structures and potential interferences from underground structures. Significant modifications or upgrades to sensitive equipment may be necessary to mitigate or avoid salt drift impacts.

Soils were not characterized for this analysis. OBGS is situated at sea level adjacent to the Pacific Ocean. Seawater intrusion or the instability of sandy soils may require additional pilings to support any large structures built at the site. Initial capital costs are summarized in Table K–16.

Table K–16. Summary of Initial Capital Costs

	Cost ($)
Cooling towers	21,400,000
Civil/structural/piping	42,300,000
Mechanical	10,900,000
Electrical	6,900,000
Demolition	0
Indirect cost	20,400,000
Condenser modification	4,100,000
Contingency	26,500,000
Total OBGS capital cost	**132,500,000**

4.4 SHUTDOWN

A portion of the work relating to installing wet cooling towers can be completed without significant disruption to the operations of OBGS. Units will be offline depending on the length of time it takes to integrate the new cooling system and conduct acceptance testing. For OBGS, a conservative estimate of 4 weeks per unit was developed. Based on 2006 generating output, however, no shutdown is forecast for either unit. Therefore, the cost analysis for OBGS does not include any loss of revenue associated with shutdown at OBGS.

This analysis did not consider shutdown with respect to the required availability of a particular generating unit, nor can it automatically be assumed that the generating profile for 2006 will be the same in each subsequent year. Net output data from 2006 may not reflect any contractual obligations that mandate a particular unit's availability during a given time period.

4.5 OPERATIONS AND MAINTENANCE

Operations and maintenance (O&M) costs for a wet cooling tower system at OBGS include routine maintenance activities; chemicals and treatment systems to control fouling and corrosion in the towers; management and labor; and an allowance for spare parts and replacement. Annual costs are calculated based on the combined tower flow rate using a base cost of $4.00/gpm in Year 1 and $5.80/gpm in Year 12, with an annual escalator of 2 percent (USEPA 2001). Year 12 costs increase based on the assumption that maintenance needs, particularly for spare parts and replacements, will be greater for years 12–20. Annual O&M costs, based on the design circulating water flow for the two cooling towers at OBGS (454,000 gpm), are presented in Table K–17. These costs reflect maximum operation.

Table K–17. Annual O&M Costs (Full Load)

	Year 1 cost ($)	Year 12 cost ($)
Management/labor	454,000	658,300
Service/parts	726,400	1,053,280
Fouling	635,600	921,620
Total OBGS O&M cost	**1,816,000**	**2,633,200**

4.6 ENERGY PENALTY

The energy penalty is divided into two components: increased parasitic use from the added electrical demand from tower fans and pumps; and the decrease in thermal efficiency from elevated turbine backpressures. Monetizing the energy penalty at OBGS requires some assumption as to how the facility will choose to alter its operations to compensate for these changes, if at all. One option would be to accept the reduced amount of revenue-generating electricity available for sale and absorb the economic loss ("production loss option"). A second option would be to increase the firing rate to the turbine (i.e., consume more fuel) and produce the same amount of revenue-generating electricity as had been obtained with the once-through cooling system ("increased fuel option"). The degree to which a facility is able, or prefers, to operate at a higher firing rate, however, produces the more likely scenario—some combination of the two.

Ultimately, the manner in which OBGS would alter operations to address efficiency changes is driven by considerations unknown to this study (e.g., corporate strategy, contractual obligations, operating protocols and turbine pressure tolerances). In all summary cost estimates, this study calculates the energy penalty's monetized value by assuming the facility will use the increased fuel option to compensate for reduced efficiency and generate the amount of electricity equivalent to the estimated shortfall. With this option, the energy penalty is equivalent to the financial cost of additional fuel and is nominally less costly than the production loss option. This option, however, may not reflect long-term costs such as increased maintenance or system degradation that may result from continued operation at a higher-than-designed turbine firing rate.[5]

The energy penalty for OBGS is calculated by first estimating the increased parasitic demand from the cooling tower pumps and fans, expressed as a percentage of each unit's rated capacity. Likewise, the change in the unit's heat rate is also expressed as a capacity percentage.

4.6.1 INCREASED PARASITIC USE (FANS AND PUMPS)

Depending on ambient conditions or the operating load at a given time, OBGS may be able to take one or more cooling tower cells offline and still obtain the required level of cooling. This would also reduce the cumulative electrical demand from the fans. For the purposes of this study, however, operations are evaluated at the design conditions, i.e., full load; no allowance is made for seasonal changes. The increased electrical demand from cooling tower fan operation is summarized in Table K–18.

Table K–18. Cooling Tower Fan Parasitic Use

	Tower Complex 1	Tower Complex 2	OBGS total
Units served	Unit 1	Unit 2	--
Generating capacity (MW)	750	750	**1,500**
Number of fans (one per cell)	18	18	**36**
Motor power per fan (hp)	263	263	--
Total motor power (hp)	4,737	4,737	**9,474**
MW total	3.53	3.53	**7.06**
Fan parasitic use (% of capacity)	**0.47%**	**0.47%**	**0.47%**

Additional circulating water pump capacity for the wet cooling towers will also increase the parasitic electricity usage at OBGS. Makeup water will continue to be withdrawn from the Pacific Ocean with one of the existing circulating water pumps; the remaining pumps will be retired.

The net increase in pump-related parasitic usage is the difference between the new wet cooling tower configuration (new plus retained pumps) and the existing once-through configuration. For calculation purposes, this study assumes full-load operation to estimate the cost of increased parasitic use. Final estimates, therefore, allocate the retained pump's electrical demand to each tower based on the proportion of the facility's generating capacity it services. Operating fewer

[5] Increasing the thermal load to the turbine will raise the circulating water temperature exiting the condenser. The cooling towers selected for this study are designed with a maximum water return temperature of approximately 120º F. Depending on each unit's operating conditions (i.e., condenser outlet temperature), the degree to which the thermal input to the turbine can be increased may be limited.

towers or tower cells will alter the allocation of the retained pump's electrical demand, but not the total demand.

Because one of the main design assumptions maintains the existing flow rate through each condenser, the new circulating pumps are single speed and are assumed to operate at their full rated capacity when in use. The increased electrical demand associated with cooling tower pump operation is summarized in Table K–19.

Table K–19. Cooling Tower Pump Parasitic Use

	Tower Complex 1	Tower Complex 2	OBGS total
Units served	Unit 1	Unit 2	**--**
Generating capacity (MW)	750	750	**1,500**
Existing pump configuration (hp)	2,000	2,000	**4,000**
New pump configuration (hp)	6,045	6,045	**12,091**
Difference (hp)	4,045	4,045	**8,091**
Difference (MW)	3.0	3.0	**6.0**
Net pump parasitic use (% of capacity)	**0.40%**	**0.40%**	**0.40%**

4.6.2 HEAT RATE CHANGE

Heat rate adjustments were calculated based on each month's ambient climate conditions and reflect the estimated difference between operations with once-through and wet cooling tower systems. As noted above, the energy penalty analysis assumes OBGS will increase its fuel consumption to compensate for lost efficiency and the increased parasitic load from fans and pumps. The higher turbine firing rate will increase the thermal load rejected to the condenser, which, in turn, results in a higher backpressure value and corresponding increase in the heat rate. No data are available describing the changes in turbine backpressures above the design thermal loads. For the purposes of monetizing the energy penalty only, this study conservatively assumed an additional increase in the heat rate of 0.5 percent at the higher firing rate; the actual effect at OBGS may be greater or less. Changes in the heat rate for each unit at OBGS are presented in Figure K–13 and Figure K–14.

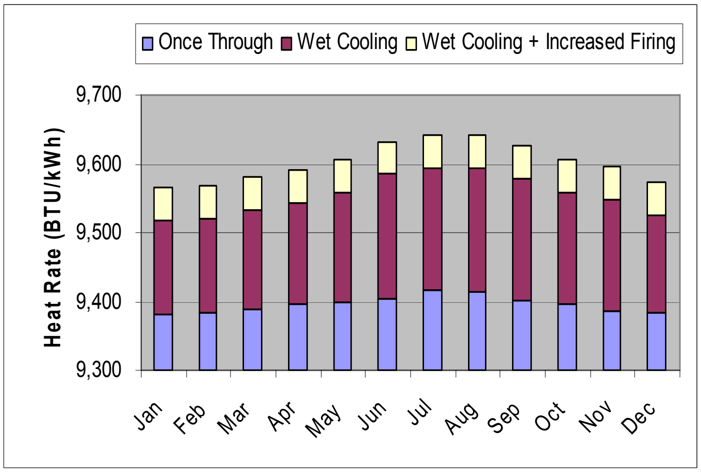

Figure K–12. Estimated Heat Rate Change (Unit 1)

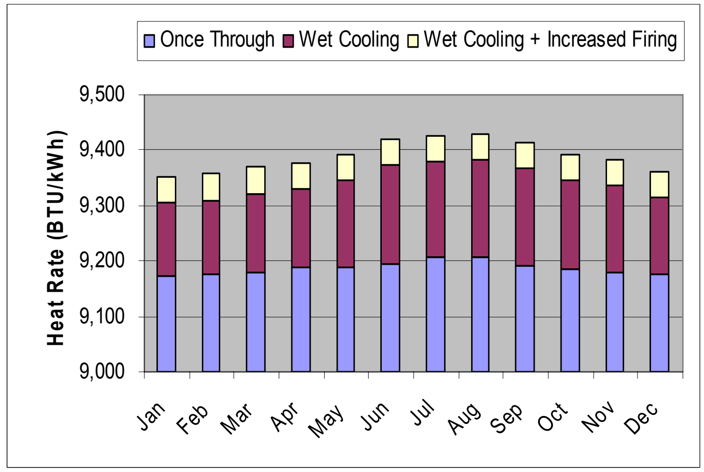

Figure K–13. Estimated Heat Rate Change (Unit 2)

4.6.3 CUMULATIVE ESTIMATE

Using the increased fuel option, the energy penalty's cumulative value is obtained by first calculating the relative costs of generation ($/MWh) for the once-through system and the wet cooling system adjusted for a higher turbine firing rate. The cost of generation for OBGS is based on the relative heat rates developed in Section 4.6 and the average monthly wholesale natural gas cost ($/MMBTU) (ICE 2006a). The difference between these two values represents the monthly increased cost, per MWh, that results from converting to wet cooling towers. This value is then applied to the net MWh generated for the each month and summed to calculate the annual cost.

Based on 2006 output data, the Year 1 energy penalty for OBGS will be approximately $600,000 million. In contrast, the energy penalty's value calculated with the production loss option would be approximately $1.1 million. Together, these values represent the range of potential energy penalty costs for OBGS. Table K–20 and Table K–21 summarize the energy penalty estimates for each unit using the increased fuel option.

Table K-20. Unit 1 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	9,380	56.28	9,566	57.39	1.11	0	0
February	5.50	9,383	51.61	9,569	52.63	1.02	0	0
March	4.75	9,388	44.59	9,582	45.51	0.92	0	0
April	4.75	9,396	44.63	9,591	45.56	0.93	0	0
May	4.75	9,398	44.64	9,606	45.63	0.99	0	0
June	5.00	9,405	47.02	9,633	48.16	1.14	0	0
July	6.50	9,416	61.20	9,641	62.66	1.46	14,356	21,002
August	6.50	9,415	61.20	9,643	62.68	1.48	0	0
September	4.75	9,401	44.65	9,627	45.73	1.07	1,583	1,700
October	5.00	9,395	46.98	9,606	48.03	1.05	0	0
November	6.00	9,387	56.32	9,596	57.57	1.25	0	0
December	6.50	9,385	61.00	9,574	62.23	1.23	0	0
							Unit 1 total	**22,702**

Table K-21. Unit 2 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	9,172	55.03	9,353	56.12	1.09	0	0
February	5.50	9,175	50.46	9,357	51.46	1.00	0	0
March	4.75	9,179	43.60	9,369	44.50	0.90	0	0
April	4.75	9,187	43.64	9,378	44.54	0.91	12,214	11,058
May	4.75	9,189	43.65	9,393	44.62	0.97	29,138	28,241
June	5.00	9,196	45.98	9,419	47.10	1.12	62,789	70,080
July	6.50	9,207	59.84	9,427	61.27	1.43	214,361	306,968
August	6.50	9,206	59.84	9,429	61.29	1.45	49,386	71,669
September	4.75	9,192	43.66	9,413	44.71	1.05	89,109	93,660
October	5.00	9,186	45.93	9,392	46.96	1.03	0	0
November	6.00	9,179	55.07	9,383	56.30	1.22	0	0
December	6.50	9,176	59.65	9,361	60.85	1.20	0	0
							Unit 2 total	**581,676**

4.7 NET PRESENT COST

The net present cost (NPC) of a wet cooling system retrofit at OBGS is the sum of all annual expenditures over the project's 20-year life span discounted according to the year in which the expense is incurred and the selected discount rate. The NPC represents the total change in revenue streams, in 2007 dollars, that OBGS can expect over 20 years as a direct result of converting to wet cooling towers. The following values were used to calculate the NPC at a 7 percent discount rate:

- *Capital and Start-up.* Includes all capital, indirect, contingency, and shutdown costs. All costs in this category are incurred in Year 0. (See Table K–16.)
- *Annual O&M.* Base cost values for Year 1 and Year 12 are adjusted for subsequent years using a 2 percent year-over-year escalator. Because OBGS has a relatively low capacity utilization factor, O&M costs for the NPC calculation were estimated at 35 percent of their maximum value. (See Table K–17.)
- *Annual Energy Penalty.* Insufficient information is available to this study to forecast future generating output at OBGS. In lieu of annual estimates, this study uses the net MWh output from 2006 as the calculation basis for Years 1 through 20. Wholesale prices include a year-over-year price escalator of 5.8 percent (based on the Producer Price Index). The energy penalty values are based on the increased fuel option discussed in Section 4.6. (See Table K–20 and Table K– 21.)

Using these values, the NPC_{20} for OBGS is $150 million. Appendix C contains detailed annual calculations used to develop this cost.

4.8 ANNUAL COST

The annual cost incurred by OBGS for a wet cooling tower retrofit is the sum of annual amortized capital costs plus the annual average of O&M and energy penalty expenditures. Capital costs are amortized at a 7 percent discount rate over 20 years. O&M and energy penalty costs are calculated in the same manner as for the NPC_{20} (Section 4.7). Revenue losses from a construction-related shutdown, if any, are incurred in Year 0 only and not included in the annual cost summarized in Table K–22.

Table K–22. Annual Cost

Discount rate (%)	Capital Cost ($)	Annual O&M ($)	Annual energy penalty ($)	Annual cost ($)
7.00%	12,500,000	700,000	1,100,000	**14,300,000**

4.9 COST-TO-GROSS REVENUE COMPARISON

Limited financial data are available to conduct a detailed analysis of the economic impact that a wet cooling system retrofit will have on OBGS's annual revenues. The facility's gross annual revenue can be approximated using 2006 net generating data (CEC 2006) and average wholesale prices for electricity as recorded at the SP 15 trading hub (ICE 2006b). This estimate, therefore, does not reflect any changes that may result from different wholesale prices or contract agreements that may increase or decrease the gross revenue summarized below, nor does it account for annual fixed revenue requirements or other variable costs.

The estimate of gross annual revenue from electricity sales at OBGS is a straightforward calculation that multiplies the monthly wholesale cost of electricity by the amount generated for the particular month. The estimated gross revenue for OBGS is summarized in Table K–23. A comparison of annual costs to annual gross revenue is summarized in Table K–24.

Table K–23. Estimated Gross Revenue

	Wholesale price ($/MWh)	2006 net output (MWh)		Estimated gross revenue ($)		
		Unit 1	Unit 2	Unit 1	Unit 2	OBGS total
January	66	0	0	0	0	**0**
February	61	0	0	0	0	**0**
March	51	0	0	0	0	**0**
April	51	0	12,214	0	622,914	**622,914**
May	51	0	29,138	0	1,486,038	**1,486,038**
June	55	0	62,789	0	3,453,395	**3,453,395**
July	91	14,356	214,361	1,306,396	19,506,851	**20,813,247**
August	73	0	49,386	0	3,605,178	**3,605,178**
September	53	1,583	89,109	83,899	4,722,777	**4,806,676**
October	57	0	0	0	0	**0**
November	66	0	0	0	0	**0**
December	67	0	0	0	0	**0**
OBGS total		**15,939**	**456,997**	**1,390,295**	**33,397,153**	**34,787,448**

Table K–24. Cost-Revenue Comparison

Estimated gross annual revenue ($)	Initial capital		O&M		Energy penalty		Total annual cost	
	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross
34,800,000	12,500,000	36.0	700,000	2.0	1,100,000	3.2	**14,300,000**	**41.0**

5.0 OTHER TECHNOLOGIES

Within the scope of this study, and using the OPC resolution's stated goal of reducing impingement and entrainment by 90–95 percent as a benchmark, the effectiveness of other technologies commonly used to address such impacts could not be conclusively determined for use at OBGS. As with many existing facilities, the site's location and configuration complicate the use of some technologies that might be used successfully elsewhere. A more detailed analysis that also comprises a biological evaluation may determine the applicability of one or more of these technologies to OBGS. A brief summary of these technologies' applicability follows.

5.1 MODIFIED RISTROPH SCREENS—FINE MESH

The principal concern with this technology is the successful return of viable organisms captured on the screens to the source water body. OBGS currently withdraws its cooling water through a submerged conduit extending approximately 2,000 feet offshore at a depth of 35 feet. Returning any collected organisms to a similar location would be impractical. It is unclear whether organisms could be returned to a near-shore location closer to the facility and remain viable.

5.2 BARRIER NETS

Barrier nets are unproven in an open ocean environment.

5.3 AQUATIC FILTRATION BARRIERS

Aquatic filtration barriers are unproven in an open ocean environment.

5.4 VARIABLE SPEED DRIVES

Variable speed drives (VSDs) were not considered for analysis at OBGS because the technology alone cannot be expected to achieve the desired level of reductions in impingement and entrainment, nor could it be combined with another technology to yield the desired reductions. Pumps that have been retrofitted with VSDs can reduce overall flow intake volumes by 10 to 50 percent over the current once-through configuration (USEPA 2001). The actual reduction, however, will vary based on the cooling water demand at different times of the year. At peak demand, the pumps will essentially function as standard circulating water pumps and withdraw water at the maximum rated capacity, thus negating any potential benefit. Use of VSDs may be an economically desirable option when pumps are retrofitted or replaced for other reasons, but they were not considered further for this study.

5.5 CYLINDRICAL FINE MESH WEDGEWIRE

Fine-mesh cylindrical wedgewire screens have not been deployed or evaluated at open coastal facilities for applications as large as would be required at OBGS (approximately 250 mgd). To function as intended, cylindrical wedgewire screens must be submerged in a water body with a consistent ambient current of 0.5 feet per second (fps). Ideally, this current would be unidirectional so that screens may be oriented properly, and any debris impinged on the screens will be carried downstream when the airburst cleaning system is activated.

Fine-mesh wedgewire screens for OBGS would be located offshore in the Pacific Ocean, south of the facility. Limited information regarding the subsurface currents in the near-shore environment near OBGS is available. Data suggest that these currents are multidirectional, depending on the tide and season, and fluctuate in terms of velocity, with prolonged periods below 0.5 fps (SCCOOS 2006). To attain sufficient depth (approximately 20 feet) and an ambient current that might allow deployment, screens would need to be located 2,000 feet or more offshore. Discussions with vendors who design these systems indicated that distances over 1,000 to 1,500 feet become problematic due to the airburst system's inability to maintain adequate pressure for sufficient cleaning (Someah 2007). Together, these considerations preclude further evaluation of fine-mesh cylindrical wedgewire screens at OBGS.

6.0 REFERENCES

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Appendix A. Once-Through and Closed-Cycle Thermal Performance

		Unit 1			Unit 2		
		Once through	Closed cycle	Net increase	Once through	Closed cycle	Net increase
JAN	Backpressure (in. HgA)	2.34	3.37	**1.03**	2.34	3.37	**1.03**
	Heat rate Δ (%)	*-0.31*	*1.16*	***1.46***	*-0.31*	*1.16*	***1.47***
FEB	Backpressure (in. HgA)	2.40	3.39	**0.99**	2.40	3.39	**0.99**
	Heat rate Δ (%)	*-0.27*	*1.19*	***1.47***	*-0.27*	*1.20*	***1.47***
MAR	Backpressure (in. HgA)	2.46	3.46	**1.00**	2.46	3.46	**1.00**
	Heat rate Δ (%)	*-0.23*	*1.33*	***1.56***	*-0.23*	*1.33*	***1.56***
APR	Backpressure (in. HgA)	2.55	3.51	**0.96**	2.55	3.51	**0.96**
	Heat rate Δ (%)	*-0.14*	*1.42*	***1.56***	*-0.14*	*1.42*	***1.56***
MAY	Backpressure (in. HgA)	2.57	3.61	**1.03**	2.57	3.61	**1.03**
	Heat rate Δ (%)	*-0.12*	*1.59*	***1.71***	*-0.12*	*1.59*	***1.71***
JUN	Backpressure (in. HgA)	2.64	3.77	**1.13**	2.64	3.77	**1.13**
	Heat rate Δ (%)	*-0.05*	*1.87*	***1.91***	*-0.05*	*1.87*	***1.92***
JUL	Backpressure (in. HgA)	2.73	3.82	**1.09**	2.73	3.82	**1.09**
	Heat rate Δ (%)	*0.07*	*1.95*	***1.88***	*0.07*	*1.96*	***1.88***
AUG	Backpressure (in. HgA)	2.72	3.83	**1.11**	2.72	3.83	**1.11**
	Heat rate Δ (%)	*0.06*	*1.98*	***1.91***	*0.06*	*1.98*	***1.92***
SEP	Backpressure (in. HgA)	2.60	3.73	**1.13**	2.60	3.73	**1.13**
	Heat rate Δ (%)	*-0.09*	*1.81*	***1.89***	*-0.09*	*1.81*	***1.90***
OCT	Backpressure (in. HgA)	2.55	3.60	**1.05**	2.55	3.60	**1.05**
	Heat rate Δ (%)	*-0.15*	*1.58*	***1.73***	*-0.15*	*1.58*	***1.73***
NOV	Backpressure (in. HgA)	2.46	3.54	**1.09**	2.46	3.54	**1.09**
	Heat rate Δ (%)	*-0.23*	*1.47*	***1.71***	*-0.23*	*1.48*	***1.71***
DEC	Backpressure (in. HgA)	2.42	3.42	**1.00**	2.42	3.42	**1.00**
	Heat rate Δ (%)	*-0.26*	*1.25*	***1.51***	*-0.26*	*1.25*	***1.51***

Note: Heat rate delta represents change from design value calculated according to estimated ambient conditions for each month.

Appendix B. Itemized Capital Costs

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
CIVIL / STRUCTURAL / PIPING	--	--	--	--	--	--	--	--	--	--
Allocation for other accessories (bends, water hammers…)	lot	1	--	--	500,000	500,000	4,000.00	85	340,000	**840,000**
Allocation for pipe racks (approx 800 ft) and cable racks	t	80	--	--	2,500	200,000	17.00	105	142,800	**342,800**
Allocation for sheet piling and dewatering	lot	1	--	--	500,000	500,000	5,000.00	100	500,000	**1,000,000**
Allocation for testing pipes	lot	1	--	--	--	--	2,000.00	95	190,000	**190,000**
Allocation for Tie-Ins to existing condenser's piping	lot	1	--	--	250,000	250,000	2,000.00	85	170,000	**420,000**
Allocation for trust blocks	lot	1	--	--	50,000	50,000	500.00	95	47,500	**97,500**
Backfill for PCCP pipe (reusing excavated material)	m3	22,042	--	--	--	--	0.04	200	176,336	**176,336**
Bedding for PCCP pipe	m3	3,321	--	--	25	83,025	0.04	200	26,568	**109,593**
Bend for PCCP pipe 42" & 48" diam (allocation)	ea	15	--	--	5,000	75,000	25.00	95	35,625	**110,625**
Bend for PCCP pipe 72" diam (allocation)	ea	30	--	--	18,000	540,000	40.00	95	114,000	**654,000**
Bend for PCCP pipe 96" diam (allocation)	ea	40	--	--	30,000	1,200,000	75.00	95	285,000	**1,485,000**
Building architectural (siding, roofing, doors, painting…etc)	ea	4	--	--	57,500	230,000	690.00	75	207,000	**437,000**
Butterfly valves 30" c/w allocation for actuator & air lines	ea	40	30,800	1,232,000	--	--	50.00	85	170,000	**1,402,000**
Butterfly valves 36" c/w allocation for actuator & air lines	ea	4	33,600	134,400	--	--	50.00	85	17,000	**151,400**
Butterfly valves 54" c/w allocation for actuator & air lines	ea	8	60,900	487,200	--	--	55.00	85	37,400	**524,600**
Butterfly valves 72" c/w allocation for actuator & air lines	ea	8	96,600	772,800	--	--	75.00	85	51,000	**823,800**
Butterfly valves 84" c/w allocation for actuator & air lines	ea	8	124,600	996,800	--	--	75.00	85	51,000	**1,047,800**
Butterfly valves 96" c/w allocation for actuator & air lines	ea	12	151,200	1,814,400	--	--	75.00	85	76,500	**1,890,900**
Check valves 36"	ea	4	48,000	192,000	--	--	24.00	85	8,160	**200,160**
Check valves 54"	ea	8	87,000	696,000	--	--	26.00	85	17,680	**713,680**
Concrete basin walls (all in)	m3	724	--	--	225	162,900	8.00	75	434,400	**597,300**
Concrete elevated slabs (all in)	m3	644	--	--	250	161,000	10.00	75	483,000	**644,000**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Concrete for transformers and oil catch basin (allocation)	m3	200	--	--	250	50,000	10.00	75	150,000	**200,000**
Concrete slabs on grade (all in)	m3	4,652	--	--	200	930,400	4.00	75	1,395,600	**2,326,000**
Ductile iron cement pipe 12" diam. for fire water line	ft	1,500	--	--	100	150,000	0.60	95	85,500	**235,500**
Excavation and backfill for fire line & make-up (using excavated material for backfill except for bedding)	m3	8,663	--	--	--	--	0.08	200	138,608	**138,608**
Excavation for PCCP pipe	m3	35,585	--	--	--	--	0.04	200	284,680	**284,680**
Fencing around transformers	m	50	--	--	30	1,500	1.00	75	3,750	**5,250**
Flange for PCCP joints 30"	ea	36	--	--	2,260	81,360	16.00	95	54,720	**136,080**
Flange for PCCP joints 72"	ea	16	--	--	9,860	157,760	25.00	95	38,000	**195,760**
Flange for PCCP joints 96"	ea	16	--	--	15,080	241,280	35.00	95	53,200	**294,480**
Foundations for pipe racks and cable racks	m3	190	--	--	250	47,500	8.00	75	114,000	**161,500**
FRP flange 30"	ea	116	--	--	1,679	194,781	50.00	85	493,000	**687,781**
FRP flange 36"	ea	16	--	--	2,500	40,000	70.00	85	95,200	**135,200**
FRP flange 54"	ea	32	--	--	5,835	186,718	80.00	85	217,600	**404,318**
FRP flange 72"	ea	8	--	--	20,888	167,101	200.00	85	136,000	**303,101**
FRP flange 84"	ea	24	--	--	33,381	801,145	300.00	85	612,000	**1,413,145**
FRP flange 96"	ea	8	--	--	40,000	320,000	500.00	85	340,000	**660,000**
FRP pipe 30" diam.	ft	600	--	--	121	72,766	0.40	85	20,400	**93,166**
FRP pipe 54" diam.	ft	320	--	--	426	136,224	0.80	85	21,760	**157,984**
FRP pipe 72" diam.	ft	400	--	--	851	340,560	1.20	85	40,800	**381,360**
FRP pipe 84" diam.	ft	200	--	--	946	189,200	1.50	85	25,500	**214,700**
FRP pipe 96" diam.	ft	1,200	--	--	2,838	3,405,600	1.75	85	178,500	**3,584,100**
Harness clamp 42" & 48" c/w internal testable joint	ea	85	--	--	2,000	170,000	16.00	95	129,200	**299,200**
Harness clamp 72" c/w internal testable joint	ea	150	--	--	2,440	366,000	18.00	95	256,500	**622,500**
Harness clamp 96" c/w internal testable joint	ea	240	--	--	3,300	792,000	22.00	95	501,600	**1,293,600**
Joint for FRP pipe 30" diam.	ea	30	--	--	1,126	33,769	50.00	85	127,500	**161,269**
Joint for FRP pipe 54" diam.	ea	16	--	--	1,324	21,190	85.00	85	115,600	**136,790**
Joint for FRP pipe 72" diam.	ea	20	--	--	3,122	62,436	200.00	85	340,000	**402,436**
Joint for FRP pipe 84" diam.	ea	10	--	--	5,014	50,138	300.00	85	255,000	**305,138**
Joint for FRP pipe 96" diam.	ea	60	--	--	17,974	1,078,440	600.00	85	3,060,000	**4,138,440**
PCCP pipe 42" dia.for make-up water line	ft	1,500	--	--	195	292,500	0.90	95	128,250	**420,750**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
PCCP pipe 72" diam.	ft	2,600	--	--	507	1,318,200	1.30	95	321,100	**1,639,300**
PCCP pipe 96" diam.	ft	4,400	--	--	890	3,916,000	2.00	95	836,000	**4,752,000**
Riser (FRP pipe 30" diam X40 ft)	ea	36	--	--	14,603	525,708	100.00	85	306,000	**831,708**
Structural steel for building	t	320	--	--	2,500	800,000	20.00	105	672,000	**1,472,000**
CIVIL / STRUCTURAL / PIPING TOTAL	**--**	**--**	**--**	**6,325,600**	**--**	**20,892,202**	**--**	**--**	**15,128,537**	**42,346,339**
ELECTRICAL	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**
4.16 kv cabling feeding MCC's	m	2,000	--	--	75	150,000	0.40	85	68,000	**218,000**
4.16kV switchgear - 4 breakers	ea	1	250,000	250,000	--	--	150.00	85	12,750	**262,750**
480 volt cabling feeding MCC's	m	1,500	--	--	70	105,000	0.40	85	51,000	**156,000**
480V Switchgear - 1 breaker 3000A	ea	6	30,000	180,000	--	--	80.00	85	40,800	**220,800**
Allocation for automation and control	lot	1	--	--	1,000,000	1,000,000	10,000.00	85	850,000	**1,850,000**
Allocation for cable trays and duct banks	m	2,000	--	--	75	150,000	1.00	85	170,000	**320,000**
Allocation for lighting and lightning protection	lot	1	--	--	150,000	150,000	1,500.00	85	127,500	**277,500**
Dry Transformer 2MVA xxkV-480V	ea	6	100,000	600,000	--	--	100.00	85	51,000	**651,000**
Lighting & electrical services for pump house building	ea	4	--	--	20,000	80,000	250.00	85	85,000	**165,000**
Local feeder for 2000 HP motor 4160 V (up to MCC)	ea	8	--	--	40,000	320,000	160.00	85	108,800	**428,800**
Local feeder for 250 HP motor 460 V (up to MCC)	ea	36	--	--	18,000	648,000	150.00	85	459,000	**1,107,000**
Oil Transformer 10/13.33MVA xx-4.16kV	ea	2	190,000	380,000	--	--	150.00	85	25,500	**405,500**
Primary breaker(xxkV)	ea	4	45,000	180,000	--	--	60.00	85	20,400	**200,400**
Primary feed cabling (assumed 13.8 kv)	m	3,000	--	--	175	525,000	0.50	85	127,500	**652,500**
ELECTRICAL TOTAL	**--**	**--**	**--**	**1,590,000**	**--**	**3,128,000**	**--**	**--**	**2,197,250**	**6,915,250**
MECHANICAL	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**
Allocation for ventilation of buildings	ea	4	25,000	100,000	--	--	250.00	85	85,000	**185,000**
Cooling tower for unit 1	lot	1	10,700,000	10,700,000	--	--	--	--	--	**10,700,000**
Cooling tower for unit 2	lot	1	10,700,000	10,700,000	--	--	--	--	--	**10,700,000**
Overhead crane 50 ton in (in pump house) Including additional structure to reduce the span	ea	4	500,000	2,000,000	--	--	1,000.00	85	340,000	**2,340,000**
Pump 4160 V 2000 HP	ea	8	1,000,000	8,000,000	--	--	500.00	85	340,000	**8,340,000**
MECHANICAL TOTAL	**--**	**--**	**--**	**31,500,000**	**--**	**0**	**--**	**--**	**765,000**	**32,265,000**

Appendix C. Net Present Cost Calculation

Project year	Capital/start-up ($)	O & M ($)	Energy penalty ($)		Total ($)	Annual discount factor	Present value ($)
			Unit 1	Unit 2			
0	132,500,000	--	--	--	132,500,000	1	**132,500,000**
1	--	544,800	22,702	581,677	1,149,179	0.9346	**1,074,022**
2	--	555,696	24,025	615,589	1,195,310	0.8734	**1,043,984**
3	--	566,810	25,426	651,478	1,243,713	0.8163	**1,015,243**
4	--	578,146	26,908	689,459	1,294,513	0.7629	**987,584**
5	--	589,709	28,477	729,654	1,347,840	0.713	**961,010**
6	--	601,503	30,137	772,193	1,403,833	0.6663	**935,374**
7	--	613,533	31,894	817,212	1,462,639	0.6227	**910,785**
8	--	625,804	33,753	864,855	1,524,413	0.582	**887,208**
9	--	638,320	35,721	915,277	1,589,318	0.5439	**864,430**
10	--	651,086	37,804	968,637	1,657,527	0.5083	**842,521**
11	--	664,108	40,008	1,025,109	1,729,225	0.4751	**821,555**
12	--	805,759	42,340	1,084,873	1,932,972	0.444	**858,240**
13	--	821,874	44,809	1,148,121	2,014,804	0.415	**836,143**
14	--	838,312	47,421	1,215,056	2,100,789	0.3878	**814,686**
15	--	855,078	50,186	1,285,894	2,191,158	0.3624	**794,075**
16	--	872,180	53,111	1,360,861	2,286,153	0.3387	**774,320**
17	--	889,623	56,208	1,440,200	2,386,031	0.3166	**755,417**
18	--	907,416	59,485	1,524,163	2,491,064	0.2959	**737,106**
19	--	925,564	62,953	1,613,022	2,601,539	0.2765	**719,325**
20	--	944,075	66,623	1,707,061	2,717,759	0.2584	**702,269**
Total							**149,835,297**

L. PITTSBURG POWER PLANT

MIRANT DELTA, LLC—PITTSBURG, CA

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1.0 GENERAL SUMMARY

Retrofitting the existing once-through cooling system at Pittsburg Power Plant (PPP) with closed-cycle wet cooling towers is technically and logistically feasible based on this study's design criteria, and will reduce cooling water withdrawals from Suisun Bay by approximately 95 percent. Impingement and entrainment impacts would be reduced by a similar proportion.

The preferred option selected for PPP includes 2 conventional wet cooling towers (without plume abatement), with individual cells arranged in a back-to-back configuration to accommodate limited space at the site. This study assumes that a portion of the existing cooling canal that is part of Unit 7's closed-cycle cooling system can be backfilled to accommodate additional cooling towers. Modifying the canal in this fashion is not expected to negatively impact to the existing towers' performance, although data describing their design specifications and performance were unavailable for review.

Space limitations would not appear to preclude plume-abated towers in the design if they were required to mitigate visual impacts. Initial capital costs for the towers would also increase by a factor of 2 or 3.

Construction-related shutdowns are estimated to take approximately 4 weeks per unit (concurrent), although PPP is not expected to incur any financial loss as a result based on 2006 capacity utilization rates for all units. The cooling tower configuration designed under the preferred option complies with all identified local use restrictions and includes necessary mitigation measures, where applicable.

1.1 COST

Initial capital and net present costs associated with installing and operating wet cooling towers at PPP are summarized in Table L–1. Annualized costs based on 20-year average values for the various cost elements are summarized in Table L–2.

Table L–1. Cumulative Cost Summary

Cost category	Cost ($)	Cost per MWh (rated capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Total capital and start-up [a]	125,400,000	10.23	280
NPC_{20}[b]	133,900,000	10.92	299

[a] Includes all costs associated with the cooling tower construction and installation and shutdown loss, if any.
[b] NPC_{20} includes all capital costs, operation and maintenance costs, and energy penalty costs over 20 years discounted at 7 percent.

Table L–2. Annual Cost Summary

Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Capital and start-up	11,800,000	0.96	26.38
Operations and maintenance	500,000	0.04	1.12
Energy penalty	400,000	0.03	0.89
Total PPP annual cost	**12,700,000**	**1.03**	**28.39**

1.2 ENVIRONMENTAL

Environmental changes associated with a cooling tower retrofit for PPP are summarized in Table L–3 and discussed further in Section 3.4.

Table L–3. Environmental Summary

		Unit 5	Unit 6
Water use	Design intake volume (gpm)	160,500	160,500
	Cooling tower makeup water (gpm)	6,800	6,800
	Reduction from capacity (%)	96	96
Energy efficiency [a]	Summer heat rate increase (%)	0.75	0.75
	Summer energy penalty (%)	2.58	2.58
	Annual heat rate increase (%)	0.89	0.89
	Annual energy penalty (%)	2.72	2.72
Direct air emissions [b]	PM_{10} emissions (tons/yr) (maximum capacity)	92	92
	PM_{10} emissions (tons/yr) (2006 capacity utilization)	6.86	4.80

[a] Reflects the comparative increase between once-through and wet cooling systems, but does not account for any operational changes to address the change in efficiency, such as increased fuel consumption (see Section 4.6).
[b] Reflects emissions from the cooling tower only; does not include any increase in stack emissions.

1.3 OTHER POTENTIAL FACTORS

None.

2.0 BACKGROUND

Pittsburg Power Plant (PPP) is a natural gas-fired steam electric generating facility located in an unincorporated section of the city of Pittsburg, Contra Costa County, owned and operated by Mirant Delta, LLC. The facility site is in the Sacramento/San Joaquin Delta on the southern bank of Suisun Bay near New York Point. PPP currently operates three steam-generating units (Units 5, 6, and 7), although only Units 5 and 6 use once-through cooling systems. Unit 7 is cooled by a closed-cycle system consisting of two crossflow wet cooling towers and a cooling canal. Units 1–4 have been retired from service. (See Table L–4 and Figure L–1.)

Table L–4. General Information

Unit	In-service year	Rated capacity (MW)	2006 capacity utilization [a]	Condenser cooling water flow (gpm)
Unit 5	1960	325	7.4%	160,500
Unit 6	1961	325	5.2%	160,500
Unit 7	1972	720	1.4%	[b]
PPP total		**1,370**	**3.7%**	**321,000**

[a] Quarterly Fuel and Energy Report—2006 (CEC 2006).
[b] Unit 7 uses a wet cooling tower.

Figure L–1. General Vicinity of Pittsburg Power Plant

2.1 COOLING WATER SYSTEM

PPP operates one cooling water intake structure (CWIS) to provide condenser cooling water to Units 5 and 6 (Figure L–2). Once-through cooling water is combined with low-volume wastes generated by PPP and discharged through a shoreline outfall to Suisun Bay. Surface water withdrawals and discharges are regulated by NPDES Permit CA0004880 as implemented by San Francisco Bay Regional Water Quality Control Board (SFBRWQCB) Order R2-2002-0072.

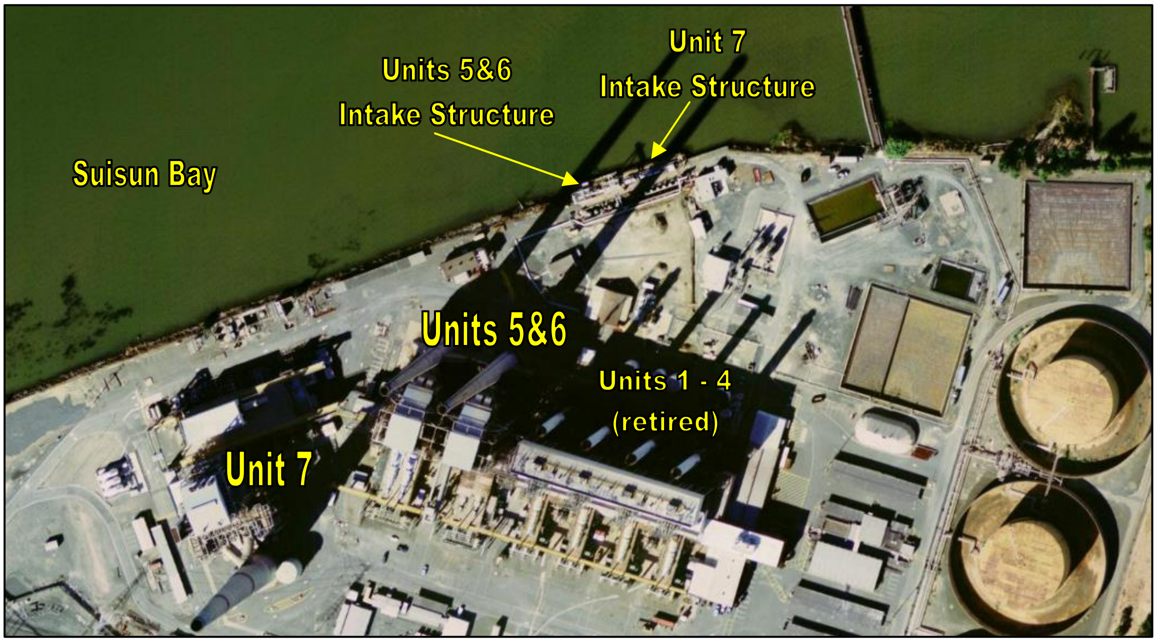

Figure L–2. Site View

Cooling water for Units 5 and 6 is withdrawn from Suisun Bay through a surface intake structure that is flush with the shoreline. Makeup water for Unit 7 is withdrawn from a separate CWIS located adjacent to the Unit 5 and 6 CWIS. This intake was previously used to provide cooling water to Units 1–4.

The Unit 5 and 6 CWIS comprises six screen bays, each fitted with a vertical traveling screen with 3/8-inch mesh panels. Three screen bays serve each unit. Screens are rotated once every 4 hours or based on the pressure differential between the upstream and downstream faces of the screen. A high-pressure spray removes any debris or fish that have become impinged on the screen face. Captured debris is collected in a dumpster for disposal in a landfill. After passing through the screens, the water flow combines into two separate channels. Four variable speed drive (VSD) pumps, two for each unit, draw water from the channels to the surface condensers. The pumps for Units 5 and 6 are each rated at 80,250 gallons per minute (gpm), or 116 million gallons per day (mgd), but capable of operating at 60 to 70 percent of the maximum capacity. The maximum rated pumping capacity for Units 5 and 6 is 321,000 gpm, or 462 mgd (SFBRWQCB 2002).

At maximum capacity, PPP maintains a total pumping capacity rated at 462 mgd. On an annual basis, PPP withdraws substantially less than its design capacity due to its low generating capacity utilization (3.7 percent for 2006; 6.3 percent for Units 5 and 6 only). When in operation and generating the maximum load, PPP can be expected to withdraw water from Suisun Bay at a rate approaching its maximum capacity.

2.2 SECTION 316(B) PERMIT COMPLIANCE

The CWIS currently in operation for Units 5 and 6 uses pumps fitted with VSDs that can reduce the intake flow volume by 30 to 40 percent depending on the each unit's operating load, particularly during sensitive spawning and migratory periods in the Delta region. At Pittsburg, this period extends from February through July when larval stages for protected species, such as the Delta smelt, are most abundant. No information was available to evaluate the VSDs' actual operations and the relative changes in intake volume they provide compared with single-speed pumps. In 2006, 80 percent of the Unit 5 and 6 net output coincided with the February to July period (CEC 2006).

Apart from the VSDs, Units 5 and 6 do not currently use other technologies or operational measures that are generally considered to be effective at reducing impingement and entrainment impacts. SFBRWQCB Order R2-2002-0072 notes that in 1986, the former owner, Pacific Gas and Electric (PG&E), implemented a Resources Management Plan to comply with BTA requirements under CWA Section 316(b). The plan required PG&E to stock striped bass fish hatcheries in the Sacramento/San Joaquin Delta and improve its intake structures. In 1992, PG&E submitted a study stating that there were no technological improvements that could achieve impingement and entrainment reductions beyond the current levels.

Finding 32 of the current order, adopted in 2002, notes:

> …[b]ased on the above-referenced CWA 316(b) study, the existing intake structure is the best intake technology available. However, in view of the consultation process and the status of Mirant's [Conservation Program], the BTA may change based on the outcome of the consultation process and implementation of Mirant's Conservation Program. (SFBRWQCB 2002, Finding 32)

Because of the potential to take protected aquatic species, such as Delta smelt and Chinook salmon, the current order requires PPP to develop a comprehensive conservation program (CP) in consultation with U.S. Fish and Wildlife Service, National Marine Fisheries Service, and California Department of Fish and Game. The CP required the installation of an aquatic filter barrier (AFB) if a concurrent pilot evaluation at Contra Costa Power Plant (CCPP) proved effective (the evaluation at CCPP was later discontinued). Mirant is also a participant in the Bay Delta Conservation Plan, which aims to develop a comprehensive conservation and restoration framework that will be compliant with the California Endangered Species Act (CESA) and the federal Endangered Species Act (ESA).

The order does not contain any numeric or narrative limitations regarding impingement or entrainment resulting from CWIS operation, but does require PPP to conduct an impingement study following the implementation of any new technologies that may result from the Resources

Management Plan. No information from the SFBRWQCB is available indicating how it intends to proceed with the permit requirements in light of the changes to the Phase II rule.

3.0 WET COOLING SYSTEM RETROFIT

3.1 OVERVIEW

This study evaluates saltwater cooling towers as a retrofit option at PPP, with the current source water (Suisun Bay) continuing to provide makeup water to the facility. Converting the existing once-through cooling system to wet cooling towers will reduce the facility's current intake capacity by approximately 96 percent; rates of impingement and entrainment will decline by a similar proportion. Use of reclaimed water was considered for PPP but not analyzed in detail because the available volume cannot serve as a replacement for once-through cooling water. The proximity of available sources, however, may make reclaimed water an attractive alternative as makeup water for a wet cooling tower system when considering additional benefits its use may provide, such as avoidance of conflicts with effluent limitations or air emission standards.

The wet cooling towers' configuration—their size, arrangement, and location—was based on best professional judgment (BPJ) using the criteria outlined in Chapter 5 and designed to meet the performance benchmarks in the most cost-effective manner. Information not available to this study that offers a more complete facility characterization may lead to different conclusions regarding the cooling towers' physical configuration.

This study developed a conceptual design of wet cooling towers sufficient to meet each active generating unit's cooling demand at its rated output during peak climate conditions. Cost estimates are based on vendor quotes developed using the available information and the various design constraints identified at PPP.

The overall practicality of retrofitting both units at PPP will require an evaluation of factors outside the scope of this study, such as each unit's age and efficiency and its role in the overall reliability of electricity production and transmission in California, particularly the San Francisco Bay region.

3.2 DESIGN BASIS

3.2.1 CONDENSER SPECIFICATIONS

For this study, the wet cooling tower conceptual design selected for PPP is based on the assumption that the condenser flow rate and thermal load to each will remain unchanged from the current system. Although no provision is included to re-optimize the condenser performance for service with a cooling tower, some modifications to the condenser (tube sheet and water box reinforcement) may be necessary to handle the increased water pressures that will result from the increased total pump head required to raise water to the cooling tower riser elevation.[1] The

[1] In this context, re-optimization refers to a comprehensive overhaul of the condenser, such as re-tubing or converting the flow from single to multiple passes. Modifications are generally limited to reinforcement measures to enable the condenser to withstand the increased pressures.

practicality and difficulty of these modifications are dependent each unit's age and configuration but are assumed to be feasible at PPP. Condenser water boxes for both units are located at grade level and appear to be readily accessible. Additional costs for condenser modifications are included in the discussion of capital expenditures (Section 4.3).

Information provided by PPP was largely used as the basis for the cooling tower design. In some cases, the data were incomplete or conflicted with values obtained from other sources. Where possible, questionable values were verified or corrected using other known information about the condenser.

For example, the condenser specification sheet for Unit 5 indicates that the existing tubes (aluminum brass) are scheduled to be replaced with titanium tubes, but no additional information is available stating whether this has occurred. If the tubes have been replaced, the condenser's thermal specifications would change and possibly alter the size selection for a wet cooling tower. In lieu of confirmed data, calculations in this study are based on the system design specifications as provided by Mirant Delta, i.e., with aluminum brass tubes for Units 5 and 6.

Likewise, the design turbine backpressure was not provided by Mirant but assumed to be 1.5 inches HgA based on other known characteristics of the cooling system (tube size, material, surface area, etc.).

Parameters used in the development of the cooling tower design are summarized in Table L–5.

Table L–5. Condenser Design Specifications

	Unit 5	Unit 6
Thermal load (MMBTU/hr)	1,410	1,410
Surface area (ft^2)	130,166	130,166
Condenser flow rate (gpm)	160,500	160,500
Tube material	Aluminum brass	Aluminum brass
Heat transfer coefficient ($BTU/hr{\bullet}ft^2{\bullet}°F$)	550	550
Cleanliness factor	0.85	0.85
Inlet temperature (°F)	62	62
Temperature rise (°F)	17.58	17.58
Steam condensate temperature (°F)	91.7	91.7
Turbine exhaust pressure (in. HgA)	1.5	1.5

3.2.2 AMBIENT ENVIRONMENTAL CONDITIONS

PPP is located in Contra Costa County along the southern shoreline of Suisun Bay in the San Joaquin/Sacramento River Delta. Cooling water is withdrawn at the surface from a shoreline intake structure. Inlet temperature data specific to PPP were not provided by Mirant Delta. As a substitute, monthly temperature data from the California Department of Water Resources Pittsburg Monitoring Station (PTS) were used in relevant calculations (DWR 2006).

The wet bulb temperature used to develop the overall cooling tower design was obtained from American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) publications. Data for the Contra Costa region indicate a 1 percent ambient wet bulb temperature of 66° F (ASHRAE 2006). A 12° F approach temperature was selected based on the site configuration and vendor input. At the design wet bulb and approach temperatures, the cooling towers will yield "cold" water at 78° F.

Monthly maximum wet bulb temperatures used in the development of energy penalty estimates in Section 4.6 were calculated using data obtained from the National Climatic Data Center (NCDC) monitoring station for Antioch, CA (NCDC 2006). Climate data used in this analysis are summarized in Table L–6.

Table L–6. Surface Water and Ambient Wet Bulb Temperatures

	Surface (°F)	Ambient wet bulb (°F)
January	48.3	50.7
February	52.1	52.8
March	58.8	55.3
April	61.2	56.6
May	65.8	59.4
June	68.5	63.0
July	71.6	66.0
August	70.7	64.3
September	68.7	61.3
October	63.9	57.3
November	57.7	55.5
December	50.9	54.5

3.2.3 LOCAL USE RESTRICTIONS

3.2.3.1 NOISE

Industrial development at PPP is regulated by the Contra Costa General Plan, although the proximity to the city of Pittsburg warrants consideration of that city's applicable policies when actions may conflict with permitted uses. Both plans outline narrative criteria to be used as a guide for future development, but do not identify numeric noise limits for new construction. Based on consultation with the city of Pittsburg Planning Department, any measures limiting noise from a wet cooling tower would be addressed through a conditional use permit in consultation with the County of Contra Costa Community Development Department that evaluates the project's specific design.

Restrictions would be based on the zoning designation for the site and community noise equivalent levels (CNELs) outlined in the General Plan's Noise Element and measured at the nearest point of impact. The cooling towers designed for PPP will have ambient noise levels no greater than 60 dBA measured at 1,000 feet. The nearest residential areas are located over 3,000 feet from the siting location. Accordingly, the wet cooling towers designed for PPP do not include noise abatement measures such as low-noise fans or barrier walls.

3.2.3.2 BUILDING HEIGHT

The developed portion of PPP is located within the heavy industry (HI) zone according to the Contra Costa General Plan. This zone is dedicated to industrial uses and does not have a restriction with regard to structural height. Given the existing height of the current structures at PPP and the proximity of residential and public recreational areas, this study selected a height restriction of 60 feet above grade level. The height of the wet cooling towers designed for PPP, from grade level to the top of the fan deck, is 56 feet.

3.2.3.3 PLUME ABATEMENT

Local zoning ordinances do not contain any specific criteria for addressing any impact associated with a wet cooling tower plume. Using the selection criteria for this study, plume abatement measures were not considered for PPP; all towers are a conventional design. The plume from wet cooling towers at PPP is not expected to adversely impact nearby infrastructure; the nearest area of immediate concern is California State Highway 4, located approximately 1.5 miles to the south. In addition, the two cooling towers that currently serve Unit 7 do not incorporate plume abatement technologies.

Community standards for assessing the visual impact associated with a cooling tower plume cannot be determined within the scope of this study. The proximity of nearby residential and commercial areas, when viewed in the context of CEC siting guidelines, may contribute to the selection of an alternate design if a wet cooling tower retrofit is undertaken at PPP in the future. These guidelines assess the total size and persistence of a visual plume with respect to aesthetic standards for bay/delta resources. Significant visual changes resulting from the plume may warrant incorporating of plume abatement measures. Installing plume-abated cooling towers at PPP will result in a different configuration (inline instead of back-to-back) and require additional space. Given the large area currently available at PPP, plume-abated towers can be installed without facing any added logistical obstacles.

3.2.3.4 DRIFT AND PARTICULATE EMISSIONS

Drift elimination measures that are considered best available control technology (BACT) are required for all cooling towers evaluated in this study, regardless of their location. State-of-the-art drift eliminators are included for each cooling tower cell at PPP, with an accepted efficiency of 0.0005 percent. Because cooling tower PM_{10} emissions are a function of the drift rate, drift eliminators are also considered BACT for PM_{10} emissions from wet cooling towers. This efficiency can be verified by a proper in situ test, which accounts for site-specific climate, water, and operating conditions. Testing based on the Cooling Tower Institute's Isokinetic Drift Test Code is required at initial start-up on only one representative cell of each tower for an approximate cost of $60,000 per test, or approximately $120,000 for both cooling towers at PPP (CTI 1994). This cost is not itemized in the final analysis and is instead included as part of the indirect cost estimate (Section 4.3).

3.2.3.5 FACILITY CONFIGURATION AND AREA CONSTRAINTS

The existing site's configuration does not present significant challenges to identifying a location for conventional cooling towers, although the selected location results in long distances between the towers and their respective generating units. As shown in Figure L–3, the property's total area is large and generally undeveloped, with few areas located close to residential or commercial areas.

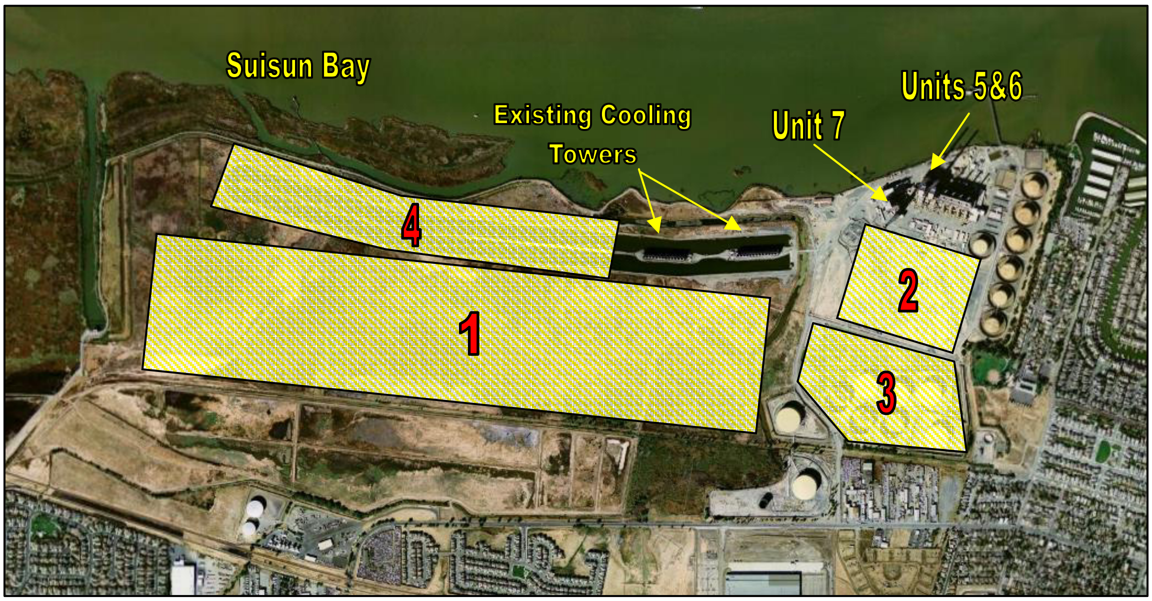

Figure L–3. Cooling Tower Siting Locations

Area 1 is the largest unoccupied parcel at PPP, with a total area greater than 500 acres. This area is undeveloped and consists of marshes and wetlands west of Willow Creek. The general area is identified as open space by the city of Pittsburg General Plan, although it is unclear how this would affect development in the area. This area was eliminated from consideration because it is undeveloped. Other developed areas would likely be prioritized to limit disruption to open spaces.

The facility's switchyard is located in Area 2. While this area would enable placement of the towers close to the generating units, the cost and complexity of relocating switchyard equipment precludes further consideration.

Area 3 is currently occupied by several large fuel storage tanks, some of which remain in use while others are in various stages of decommissioning. Because other areas are available, this parcel was not considered further.

Area 4 is an extension of the cooling canal west of the existing Unit 7 cooling towers. The available space in the canal (approximately 41 acres) is more than adequate to accommodate the wet cooling towers designed for Units 5 and 6. Placement in this area, however, will require backfilling a portion of the canal. Based on the canal's size and the estimated thermal load for Unit 7, any disruption to the canal's flow caused by additional towers is not expected to be significant. The new cooling towers for Units 5 and 6 will not use the open canal for cooling; all water will be routed directly from the cold water basin to the condenser.

3.3 CONCEPTUAL DESIGN

Based on the design constraints discussed above, two wet cooling towers were selected to replace the current once-through cooling system that serves Units 5 and 6 at PPP. Each unit will be served by an independently functioning tower with separate pump houses and pumps. Both towers at PPP consist of conventional cells arranged in a multicell, back-to-back configuration.

3.3.1 SIZE

Each tower is constructed over a concrete collection basin 4 feet deep. The basin is larger than the tower structure's footprint, extending an additional 2 feet in each direction. The concrete used for construction is suitable for saltwater applications. The principal tower material is fiberglass reinforced plastic (FRP), with stainless steel fittings. These materials are more resistant to the higher corrosive effects of saltwater.

The size of each tower is primarily based on the thermal load rejected to the tower by the surface condenser and a 12° F approach to the ambient wet bulb temperature. Flow rates through each condenser remain unchanged.

General characteristics of the wet cooling towers selected for PPP are summarized in Table L–7.

Table L–7. Wet Cooling Tower Design

	Tower 1 (Unit 5)	Tower 2 (Unit 6)
Thermal load (MMBTU/hr)	1,410	1,410
Circulating flow (gpm)	160,500	160,500
Number of cells	12	12
Tower type	Mechanical draft	Mechanical draft
Flow orientation	Counterflow	Counterflow
Fill type	Modular splash	Modular splash
Arrangement	Back-to-back	Back-to-back
Primary tower material	FRP	FRP
Tower dimensions (l x w x h) (ft)	324 x 96 x 56	324 x 96 x 56
Tower footprint with basin (l x w) (ft)	328 x 100	328 x 100

3.3.2 LOCATION

The initial site selection for each tower was based on the desire to locate each tower as close as possible to the respective generating units to minimize the supply and return pipe distances and any increases in total pump head and brake horsepower. At PPP, the linear distance between the generating units and towers is large (approximately 4,000 feet) but does not present any significant challenges for placing the supply and return pipelines (Figure L–4).

Figure L-4. Cooling Tower Locations

3.3.3 PIPING

The main supply and return pipelines to and from both towers will be located underground and made of prestressed concrete cylinder pipe (PCCP) suitable for saltwater applications. These pipes range in size from 72 to 84 inches in diameter. The distance between towers 1 and 2 and their respective generating units requires roughly 15,000 feet of PCCP for the supply and return lines. Pipes connecting the condensers to the supply and return lines are made of FRP and placed above ground on pipe racks. Above-ground placement avoids the potential disruption that may be caused by excavation in and around the power block. The condensers at PPP are all located at grade level, enabling a relatively straightforward connection.

All riser piping (extending from the foot of the tower to the level of water distribution) is constructed of FRP.

Potential interference with underground obstacles and infrastructure is a concern, particularly at existing sites that are several decades old and have been substantially modified or rebuilt in the interim. Avoidance of these obstacles is considered to the degree practical in this study. Associated costs are included in the contingency estimate and are generally higher than similar estimates for new facilities (Section 4.3).

Appendix B details the total quantity of each pipe size and type for PPP.

3.3.4 FANS AND PUMPS

Each tower cell uses an independent single-speed fan. The fan size and motor power are the same for each cell in each tower.

This analysis includes new pumps to circulate water between the condensers and cooling towers. Pumps are sized according to the flow rate for each tower, the relative distance between the towers and condensers, and the total head required to deliver water to the top of each cooling tower riser. A separate, multilevel pump house is constructed for each tower and sized to accommodate the motor control centers (MCCs) and appropriate electrical switchgear. The electrical installation includes all necessary transformers, cabling, cable trays, lighting, and lightning protection. A 50-ton overhead crane is also included to allow for pump servicing.

Fan and pump characteristics associated with wet cooling towers at PPP are summarized in Table L–8. The net electrical demand of fans and new pumps is discussed further as part of the energy penalty analysis in Section 4.6.

Table L–8. Cooling Tower Fans and Pumps

		Tower 1 (Unit 5)	Tower 2 (Unit 6)
Fans	Number	12	12
	Type	Single speed	Single speed
	Efficiency	0.95	0.95
	Motor power (hp)	211	211
Pumps	Number	2	2
	Type	50 % recirculating Mixed flow Suspended bowl Vertical	50 % recirculating Mixed flow Suspended bowl Vertical
	Efficiency	0.88	0.88
	Motor power (hp)	3,182	3,182

3.4 ENVIRONMENTAL EFFECTS

Converting the existing once-through cooling system at PPP to wet cooling towers will significantly reduce the intake of seawater from Suisun Bay and will presumably reduce impingement and entrainment by a similar proportion. Because closed-cycle systems will almost always result in condenser cooling water temperatures higher than those found in a comparable once-through system, wet towers will increase the operating heat rates at both of PPP's steam units, thereby decreasing the facility's overall efficiency. Additional power will also be consumed by the tower fans and circulating pumps.

Depending on how PPP chooses to address this change in efficiency, total stack emissions may increase for pollutants such as PM_{10}, SO_x, and NO_x, and may require additional control measures (e.g., electrostatic precipitation, flue gas desulfurization, and selective catalytic reduction) or the purchase of emission credits to meet air quality regulations. The availability of emission reduction credits (ERCs) and their associated cost was not evaluated as part of this study. Both factors, however, may limit the air emission compliance options available to PPP.

No control measures are currently available for CO_2 emissions, which will increase, on a per-kWh basis, by the same proportion as any change in the heat rate. The towers themselves will constitute an additional source of PM_{10} emissions, the annual mass of which will largely depend on the capacity utilization rate for the generating units served by each tower.

If PPP retains its NPDES permit to discharge wastewater to Suisun Bay with a wet cooling tower system, it may have to address revised effluent limitations resulting from the substantial change in the discharge quantity and characteristics. Thermal impacts from the current once-through system, if any, will be minimized with a wet cooling system.

3.4.1 AIR EMISSIONS

PPP is located in the San Francisco Bay Area air basin. Air emissions are permitted by the Bay Area Air Quality Management District (BAAQMD) (Facility ID A0012).

Drift volumes are expected to be within the range of 0.5 gallons for every 100,000 gallons of circulating water in the towers. At PPP, this corresponds to a rate of approximately 1.6 gpm based on the maximum combined flow both towers. Because the area selected for wet cooling towers is located at a substantial distance from sensitive structures, salt drift deposition is not likely to be a significant concern.

Total PM_{10} emissions from the PPP cooling towers are a function of the number of hours in operation, overall water quality in the tower, and evaporation rate of drift droplets prior to deposition on the ground. Makeup water at PPP will be obtained from the same source currently used for once-through cooling water (Suisun Bay). Water within the bay is heavily influenced by freshwater inflows from the Sacramento and San Joaquin Rivers, but is also affected by tidal cycles in the delta region. Water is considered to be brackish, with salinity levels varying by season and tide. For the purposes of this study, cooling towers were developed based on marine total dissolved solids (TDS) concentrations. At 1.5 cycles of concentration and assuming an initial TDS value of 35 parts per thousand (ppt), the water within the cooling towers will reach a maximum TDS level of roughly 53 ppt. Any drift droplets exiting the tower will have the same TDS concentration.

The cumulative mass emission of PM_{10} from PPP will increase as a result of the direct emissions from the cooling towers themselves. Stack emissions of PM_{10}, as well as SO_x, NO_x, and other pollutants, will increase due to the drop in fuel efficiency, although the cumulative increase will depend on actual operations and emission control technologies currently in use. Maximum drift and PM_{10} emissions from the cooling towers are summarized in Table L–9.[2]

[2] This is a conservative estimate that assumes all dissolved solids present in drift droplets will be converted to PM_{10}. Studies suggest this may overestimate actual emission profiles for saltwater cooling towers (Chapter 4).

Data summarizing the total facility emissions for these pollutants in 2005 are presented in Table L–10 (CARB 2005). In 2005, PPP operated at an annual capacity utilization rate of 6.3 percent. Using this rate, the additional PM_{10} emissions from the cooling towers would increase the facility total by approximately 12 tons/year, or 29 percent.[3]

Table L–9. Full Load Drift and Particulate Estimates

	PM_{10} (lbs/hr)	PM_{10} (tons/year)	Drift (gpm)	Drift (lbs/hr)
Tower 1	21	92	0.8	402
Tower 2	21	92	0.8	402
Total PPP PM_{10} and drift emissions	**42**	**184**	**1.6**	**804**

Table L–10. 2005 Emissions of SO_x, NO_x, PM_{10}

Pollutant	Tons/year
NO_x	71.3
SO_x	7.2
PM_{10}	40.6

3.4.2 MAKEUP WATER

The volume of makeup water required by both cooling towers at PPP is the sum of evaporative loss and the blowdown volume required to maintain the circulating water in each tower at the design TDS concentration. Drift expelled from the towers represents an insignificant volume by comparison and is accounted for by rounding up evaporative loss estimates. Makeup water volumes are based on design conditions, and may fluctuate seasonally depending on climate conditions and facility operations. Wet cooling towers will reduce once-through cooling water withdrawals from Suisun Bay by approximately 96 percent over the current design intake capacity.

Table L–11. Makeup Water Demand

	Tower circulating flow (gpm)	Evaporation (gpm)	Blowdown (gpm)	Total makeup water (gpm)
Tower 1	160,500	2,400	4,600	7,000
Tower 2	160,500	2,400	4,600	7,000
Total PPP makeup water demand	**321,000**	**4,800**	**9,200**	**14,000**

One circulating water pump, rated at 80,250 gpm, which is currently used to provide once-through cooling water to the facility, will be retained in a wet cooling system to provide makeup water to each cooling tower. The retained pump's capacity exceeds the makeup demand by approximately 66,000 gpm. Any excess capacity will be routed through a bypass conduit and returned to the wet well at a point located behind the intake screens. Recirculating the excess capacity in this manner reduces additional cost that would be incurred if new pumps were required while maintaining the desired flow reduction. The intake of new water, measured at the

[3] 2006 emission data are not currently available from the Air Resources Board Web site. For consistency, the comparative increase in PM_{10} emissions estimated here is based on the 2005 PPP capacity utilization rate instead of the 2006 rate presented in Table L-4. All other calculations in this chapter use the 2006 value.

intake screens, will be equal to the cooling towers' makeup water demand. Figure L–5 presents a schematic of this configuration.

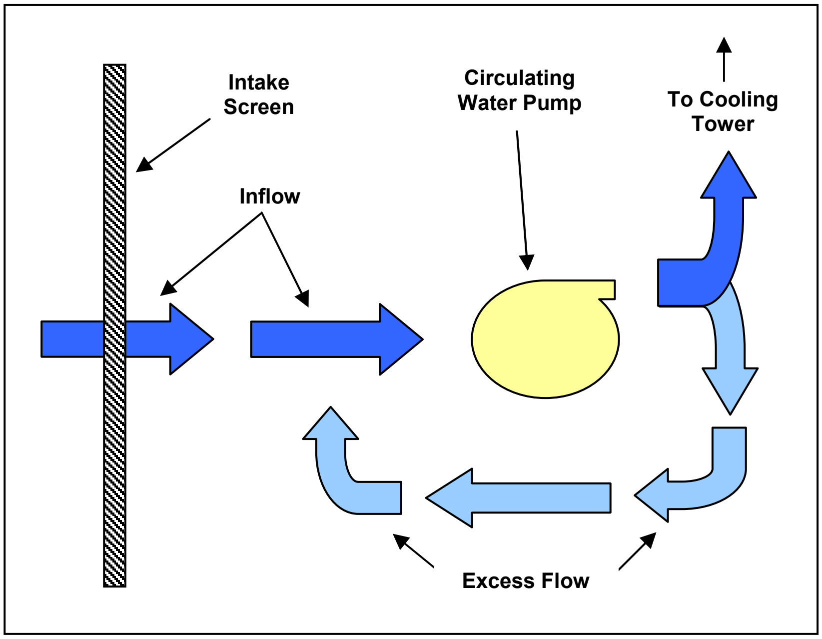

Figure L–5. Schematic of Intake Pump Configuration

The existing once-through cooling system at PPP does not treat water withdrawn from Suisun Bay with the exception of screening for debris and larger organisms and periodic chlorination to control biofouling in the condenser tubes. Conversion to a wet cooling tower system will not interfere with chlorination operations.

Makeup water will continue to be withdrawn from Suisun Bay.

The wet cooling tower system proposed for PPP includes water treatment for standard operational measures, i.e., corrosion inhibitors, biocides, and anti-scaling agents. An allowance for these additional chemical treatments is included in annual O&M costs. It is assumed that the current once-through cooling water quality will be acceptable for use in a seawater cooling tower (with continued screening and chlorination) and will not require any pretreatment to enable its use.

3.4.3 NPDES PERMIT COMPLIANCE

At maximum operation, wet cooling towers at PPP will result in an effluent discharge of approximately 13 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, floor drain wastes, and cleaning wastes. These low-volume wastes may add an additional 0.8 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, PPP will be required to modify its existing individual wastewater discharge (NPDES) permit.

Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0004880 as implemented by SFBRWQCB Order R2-2002-0072. All once-through cooling water and process wastewaters are discharged through a shoreline outfall to Suisun Bay. The existing order contains effluent limitations based on the California Toxics Rule (CTR), the 1972 Thermal Plan and the San Francisco Bay Basin Water Quality Control Plan ("Basin Plan").

PPP will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities (40 CFR 423.13(d)(1)). These ELGs set numeric limitations for chromium and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity). Because ELGs are technology-based limitations, mixing zones or dilution factors are not applicable when determining compliance; limits must be met at the point of discharge from the cooling tower prior to commingling with any other waste stream. ELGs for cooling tower blowdown target priority pollutants that are contributed by maintenance chemicals and do not apply when limits may be exceeded as a result of background concentrations or other sources. Further discussion can be found in Chapter 4, Section 3.6.

Conversion to wet cooling towers will alter the volume and composition of a facility's wastewater discharge because wet towers concentrate certain pollutants in the effluent waste stream. The cooling towers designed for PPP operate at 1.5 cycles of concentration, i.e., the blowdown discharge will contain a dissolved solids concentration 50 percent higher than the makeup water.

Changes to discharge composition may affect compliance with water quality criteria included in the SIP. If compliance with these objectives becomes problematic, alternative treatment or discharge methods may be necessary. Compliance may be achieved by altering the discharge configuration in such a way as to increase dilution (e.g., diffuser ports), or by seeking a mixing zone and dilution credits as permissible under the SIP and Basin Plan. Alternately, some low volume waste streams (e.g., boiler blowdown, laboratory drains) may be diverted, with necessary permits, for treatment at a POTW.

If more pollutant-specific treatment methods, such as filtration or precipitation technologies, become necessary to meet WQBELs, the initial capital cost may range from \$2 to \$5.50 per 1,000 gallons of treatment capacity, with annual costs of approximately \$0.5 per gallon of capacity, depending on the method of treatment (FRTR 2002). Hazardous material disposal fees and permits would further increase costs.

This evaluation did not include alternative discharge or effluent treatment measures in the conceptual design because the variables used to determine final WQBELs, which would be used to determine the type and scope of the desired compliance method, cannot be quantified here. Likewise, the final cost evaluation (Section 4.0) does not include any allowance for these possibilities.

Existing thermal discharges to an estuary are limited to a maximum discharge temperature of 20º F above the receiving water's natural temperature, may not exceed 86º F, and must meet other criteria specified by the Thermal Plan (SWRCB 1972). PPP applied for, and received, an exception to this Thermal Plan requirement. The current order permits the discharge of elevated-temperature wastes that do not exceed the natural receiving water temperature by more than 28º F at flood tide (SFBRWQCB 2002). No information was available to assess compliance with this permit requirement. Because cooling tower blowdown will be taken from the "cold" side of the tower, conversion to a wet cooling system will significantly reduce the discharge temperature (to less than 78º F) and the size of any related thermal plume in the receiving water, thus enabling PPP to meet the initial requirements of the Thermal Plan.

3.4.4 RECLAIMED WATER

Reclaimed or alternative water sources used in conjunction with wet cooling towers could eliminate all surface water withdrawals at PPP. Doing so would completely eliminate impingement and entrainment concerns, and might enable the facility to avoid possible effluent quality and permit compliance issues, depending on the quality of reclaimed water available for use. In addition, wet cooling towers using reclaimed water would be expected to have lower PM_{10} emissions due to the lower TDS levels. The California State Water Resources Control Board (SWRCB), in 1975, issued a policy statement requiring the consideration of alternative cooling methods in new power plants, including reclaimed water, over the use of freshwater (SWRCB 1975). There is no similar policy regarding marine waters, but the clear preference of state agencies is to encourage alternative cooling methods, including reclaimed water, wherever possible.

The present volume of available reclaimed water within a 15-mile radius of PPP (62 mgd) does not meet the current once-through cooling demand; thus, reclaimed water is only applicable as a source of makeup water for a wet cooling tower system. This study did not pursue a detailed investigation of reclaimed water's use because the conversion of PPP's once-through cooling system to saltwater cooling towers meets the performance benchmarks for impingement and entrainment impact reductions discussed in the 2006 California Ocean Protection Council (OPC) Resolution on Once-Through Cooling Water (see Chapter 1).

To be acceptable for use as makeup water in cooling towers, reclaimed water must meet tertiary treatment and disinfection standards under California Code of Regulations (CCR) Title 22. If the reclaimed water is not treated to the required levels, PPP would be required to arrange for sufficient treatment, either onsite or at the source facility, prior to its use in the cooling towers.

An additional consideration for reclaimed water is the presence of any ammonia or ammonia-forming compounds in the reclaimed water. All the condenser tubes at PPP contain copper alloys (aluminum brass) and can experience stress-corrosion cracking as a result of the interaction between copper and ammonia. Treatment for ammonia may include adding ferrous sulfate as a corrosion inhibitor or require ammonia-stripping towers to pretreat reclaimed water prior to use in the cooling towers (USEPA 2000).

Three publicly owned treatment works (POTWs) were identified within a 15-mile radius of PPP, with a combined discharge capacity of 62 mgd. Figure L–6 shows the relative locations of these facilities to PPP.

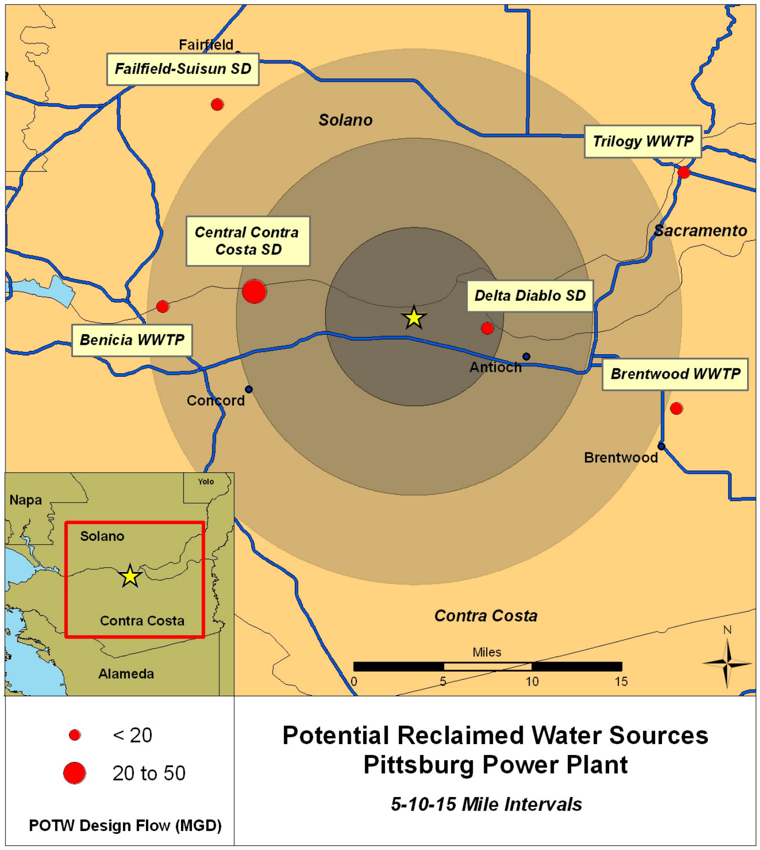

Figure L–6. Reclaimed Water Sources

- *City of Benicia Wastewater Treatment Plant—Benicia.*
  Discharge volume: 3 mgd
  Distance: 13 miles W
  Treatment level: Secondary

  All water is treated to secondary standards. No claims to or uses of treated effluent were identified. Using this water as a makeup source would require tertiary treatment as well as installing a transmission pipeline across Suisun Bay or the Carquinez Strait to reach PPP. The available capacity would be sufficient to provide approximately one-third of the makeup water required for freshwater cooling towers at PPP (9 to 12 mgd).

- *Central Contra Costa Sanitation District (CCCSD)—Concord.*
  Discharge volume: 45 mgd
  Distance: 9.5 miles W
  Treatment level: 33 % Secondary; 67 % Tertiary

  CCCSD has the capacity to treat approximately 30 mgd of effluent to tertiary treatment standards. Most reclaimed water produced by the facility is used for local irrigation projects and other non-potable uses. The balance of effluent that is treated to secondary standards (15 mgd) would be sufficient to provide all makeup water required for freshwater cooling towers at PPP (9 to 12 mgd), although arrangements for tertiary treatment would have to be made prior to its use.

- *Delta Diablo Sanitation District (DDSD)—Antioch.*
  Discharge volume: 14 mgd
  Distance: 4.5 miles E
  Treatment level: 40 % Secondary; 60 % Tertiary

  DDSD has the capacity to treat approximately 8 mgd of effluent to tertiary treatment standards. Reclaimed water is currently used as makeup water for the Los Medanos Energy Center, Delta Energy Center, and small irrigation projects in the region. The balance of effluent that is treated to secondary standards (6 mgd) would be sufficient to provide two-thirds of the freshwater tower makeup demand at PPP (9 to 12 mgd), although arrangements for tertiary treatment would have to be made prior to its use.

The costs associated with installing transmission pipelines (excavation/drilling, material, labor), in addition to design and permitting costs, are difficult to quantify in the absence of a detailed analysis of various site-specific parameters that will influence the final configuration. The nearest facility with sufficient capacity to satisfy PPP's makeup demand (9 to 12 mgd for freshwater towers) is located 9.5 miles west of the facility (CCCSD).

Based on data compiled for this study and others, the estimated installed cost of a 24-inch prestressed concrete cylinder pipe, sufficient to provide 12 mgd to PPP, is $300 per linear foot, or approximately $1.6 million per mile. Additional considerations, such as pump capacity and any required treatment, would increase the total cost.

Regulatory concerns beyond the scope of this investigation, however, may make reclaimed water (as a makeup water source) comparable or preferable to brackish water from Suisun Bay. Reclaimed water may enable PPP to eliminate potential conflicts with water discharge limitations or reduce PM_{10} emissions from the cooling tower, which is a concern given the San Francisco Bay Area air basin's current nonattainment status.

At any facility where wet cooling towers are a feasible alternative, reclaimed water may be used as a makeup water source. The practicality of its use, however, depends on the overall cost, availability, and additional environmental benefit that may occur.

3.4.5 THERMAL EFFICIENCY

Wet cooling towers at PPP will increase the condenser inlet water temperature by a range of 6 to 21° F above the surface water temperature, depending on the ambient wet bulb temperature at the time. The generating units at PPP are designed to operate at the conditions described in Table L–12. The resulting monthly difference between once-through and wet cooling tower condenser inlet temperatures is described in Figure L–7.

Table L–12. Design Thermal Conditions

	Unit 5	Unit 6
Design backpressure (in. HgA)	1.5	1.5
Design water temperature (°F)	62	62
Turbine inlet temp (°F)	1,000	1,000
Turbine inlet pressure (psia)	2,000	2,000
Full load heat rate (BTU/kWh) [a]	7,510	7,510

[a] Mirant Delta 2006.

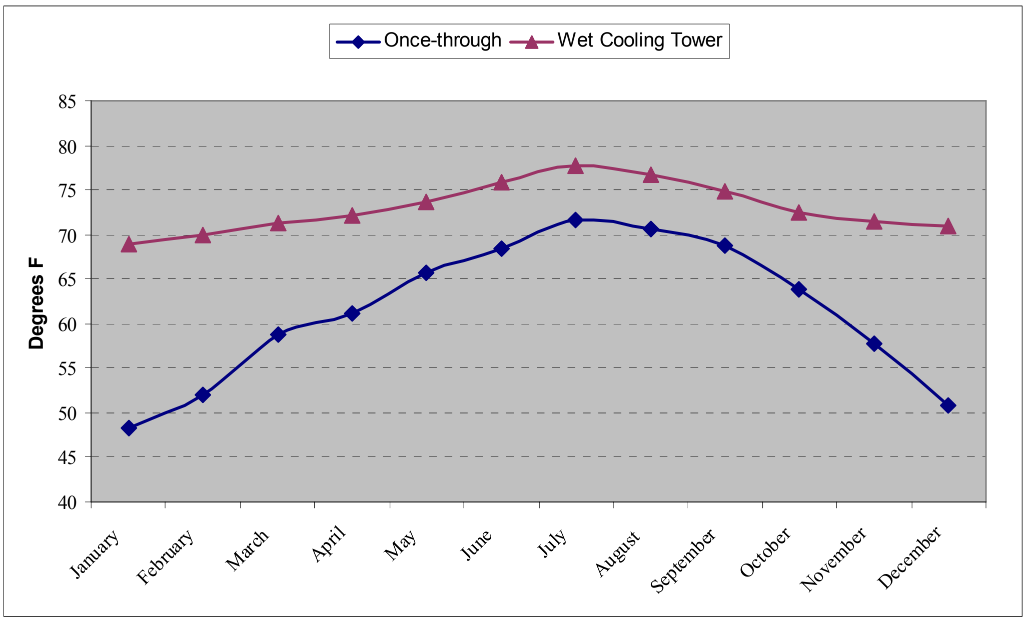

Figure L–7. Condenser Inlet Temperatures

Backpressures for the once-through and wet cooling tower configurations were calculated for each month using the design criteria described in the sections above and ambient climate data. In general, backpressures associated with the wet cooling tower were elevated by 1.0 to 1.15 inches HgA compared with the current once-through system (Figure L–8 and Figure L–10).

Heat rate adjustments were calculated by comparing the theoretical change in available energy that occurs at different turbine exhaust backpressures, assuming the thermal load and turbine inlet pressure remain constant, i.e., at the full load rating.[4] The relative change at different backpressures was compared with the value calculated for the design conditions (i.e., at design

[4] Changes in thermal efficiency estimated for PPP are based on the design specifications provided by the facility. This may not reflect system modifications that might influence actual performance. In addition, the age of the units and the operating protocols used by PPP might result in different calculations.

turbine inlet and exhaust backpressures) and plotted as a percentage of the full load operating heat rate to develop estimated correction curves (Figure L–9 and Figure L–11).

The difference between the estimated once-through and closed-cycle heat rates for each month represents the approximate heat rate increase that would be expected when converting to wet cooling towers.

Table L–13 summarizes the annual average heat rate increase for each unit as well as the increase associated with the peak demand period of July-August-September. Monthly values were used to calculate the monetized value of these heat rate changes (Section 4.6). Month-by-month calculations are presented in Appendix A.

Table L–13. Summary of Estimated Heat Rate Increases

	Unit 5	Unit 6
Peak (July-August-September)	0.75%	0.75%
Annual average	0.89%	0.89%

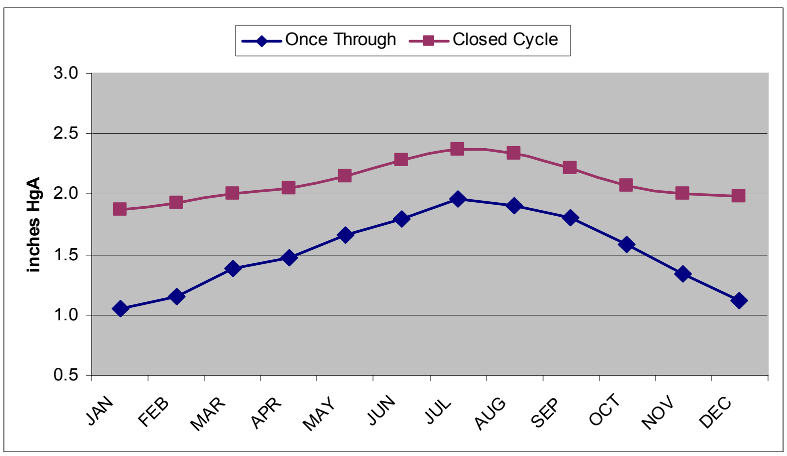

Figure L–8. Estimated Backpressures (Unit 5)

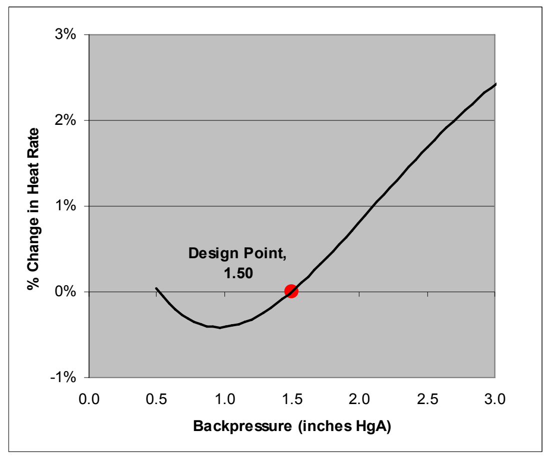

Figure L–9. Estimated Heat Rate Correction (Unit 5)

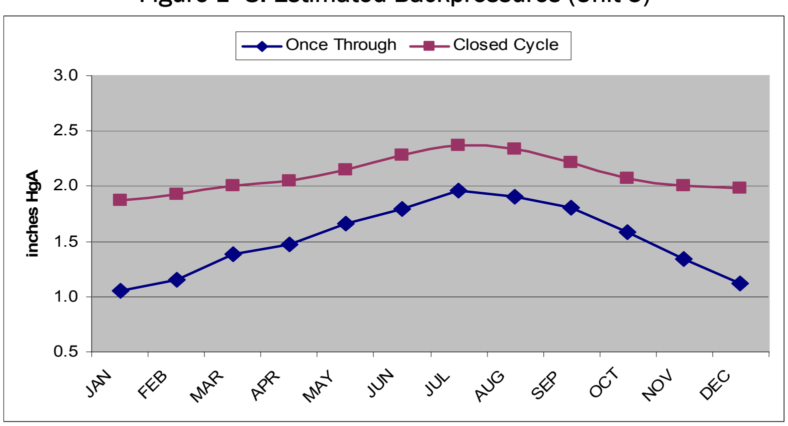

Figure L–10. Estimated Backpressures (Unit 6)

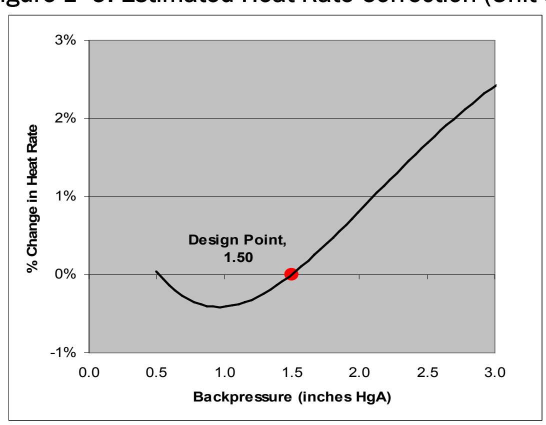

Figure L–11. Estimated Heat Rate Correction (Unit 6)

4.0 RETROFIT COST ANALYSIS

The wet cooling system retrofit estimate for PPP is based on incorporating conventional wet cooling towers as a replacement for the existing once-through system for each unit. Standard cost elements for this project include the following:

- Direct (cooling tower installation, civil/structural, mechanical, piping, electrical, and demolition)
- Indirect (smaller project costs not itemized)
- Contingency (allowance for unknown project variables)
- Revenue loss from shutdown (net loss in revenue during construction phase)
- Operations and maintenance (non–energy related cooling tower operations)
- Energy penalty (includes increased parasitic use from fans and pumps as well as decreased thermal efficiency)

The cost analysis does not include allowances for elements that are not quantified in this study, such as land acquisition, effluent treatment, or air emission reduction credits. The methodology used to develop cost estimates is discussed in Chapter 5.

4.1 COOLING TOWER INSTALLATION

In general, the cooling tower configuration selected for PPP conforms to a typical design; no significant variations from a conventional arrangement were needed. Table L–14 summarizes the design-and-build cost estimate for each tower developed by vendors, inclusive of all labor and management required for their installation.

Table L–14. Wet Cooling Tower Design-and-Build Cost Estimate

	Unit 5	Unit 6	PPP total
Number of cells	12	12	**24**
Cost/cell ($)	566,667	566,667	**566,667**
Total PPP D&B cost ($)	**6,800,000**	**6,800,000**	**13,600,000**

4.2 OTHER DIRECT COSTS

A significant portion of wet cooling tower installation costs result from the various support structures, materials, equipment and labor necessary to prepare the cooling tower site and connect the towers to the condenser. At PPP, these costs comprise approximately 80 percent of the initial capital cost. Line item costs are detailed in Appendix B.

Deviations from or additions to the general cost elements discussed in Chapter 5 are discussed below. Other direct costs (non–cooling tower) are summarized in Table L–15.

- *Civil, Structural, and Piping*
  The cooling towers' location with respect to the generating units represents the largest single increase in cost over an average configuration. More than 15,000 feet of large diameter pipe are required to service both cooling towers.
- *Mechanical and Electrical*
  Initial capital costs in this category reflect the new pumps (four total) to circulate cooling water between the towers and condensers. No new pumps are required to provide makeup water from Suisun Bay. Electrical costs are based on the battery limit after the main feeder breakers.
- *Demolition*
  No demolition costs are required.

Table L–15. Summary of Other Direct Costs

	Equipment ($)	Bulk material ($)	Labor ($)	PPP total ($)
Civil/structural/piping	5,300,000	26,600,000	16,600,000	**48,500,000**
Mechanical	7,600,000	0	700,000	**8,300,000**
Electrical	1,600,000	2,700,000	2,500,000	**6,800,000**
Demolition	0	0	0	**0**
Total PPP other direct costs	**14,500,000**	**29,300,000**	**19,800,000**	**63,600,000**

4.3 INDIRECT AND CONTINGENCY

Indirect costs are calculated as 25 percent of all direct costs (civil/structural, mechanical, electrical, demolition, and cooling towers).

An additional allowance is included for condenser water box and tube sheet reinforcement to withstand the increased pressures associated with a recirculating system. Each condenser may require reinforcement of the tube sheet bracing with 6-inch x 1-inch steel, and water box reinforcement/replacement with 5/8-inch carbon steel. Based on the estimates outlined in Chapter 5, a conservative estimate of 5 percent of all direct costs is included to account for possible condenser modifications.

The contingency cost is calculated as 25 percent of the sum of all direct and indirect costs, including condenser reinforcement. At PPP, potential costs in this category include relocating or demolishing small buildings and structures and potential interferences from underground structures.

Soils were not characterized for this analysis. PPP is situated near sea level adjacent to Suisun Bay. The area in which cooling towers will be located is surrounded by marshes and wetlands that may require additional pilings to support any large structures built at the site. Initial capital costs are summarized in Table L–16.

Table L–16. Summary of Initial Capital Costs

	Cost ($)
Cooling towers	13,600,000
Civil/structural/piping	48,500,000
Mechanical	8,300,000
Electrical	6,800,000
Demolition	0
Indirect cost	19,300,000
Condenser modification	3,900,000
Contingency	25,100,000
Total PPP capital cost	**125,500,000**

4.4 SHUTDOWN

A portion of the work relating to installing wet cooling towers can be completed without significant disruption to the operations of PPP. Units will be offline depending on the length of time it takes to integrate the new cooling system and conduct acceptance testing. For PPP, a conservative estimate of 4 weeks per unit was developed. Based on 2006 generating output, however, no shutdown is forecast for either unit. Therefore, the cost analysis for PPP does not include any loss of revenue associated with shutdown at PPP.

This analysis did not consider shutdown with respect to the required availability of a particular generating unit, nor can it automatically be assumed that the generating profile for 2006 will be the same in each subsequent year. Net output data from 2006 may not reflect any contractual obligations that mandate a particular unit's availability during a given time period.

4.5 OPERATIONS AND MAINTENANCE

Operations and maintenance (O&M) costs for a wet cooling tower system at PPP include routine maintenance activities; chemicals and treatment systems to control fouling and corrosion in the towers; management and labor; and an allowance for spare parts and replacement. Annual costs are calculated based on the combined tower flow rate using a base cost of $4.00/gpm in Year 1 and $5.80/gpm in Year 12, with an annual escalator of 2 percent (USEPA 2001). Year 12 costs increase based on the assumption that maintenance needs, particularly for spare parts and replacements, will be greater for years 12–20. Annual O&M costs, based on the design circulating water flow for the two cooling towers at PPP (321,000 gpm), are presented in Table L–17. These costs reflect maximum operation.

Table L–17. Annual O&M Costs (Full Load)

	Year 1 cost ($)	Year 12 cost ($)
Management/labor	321,000	465,450
Service/parts	513,600	744,720
Fouling	449,400	651,630
Total PPP O&M cost	**1,284,000**	**1,861,800**

4.6 ENERGY PENALTY

The energy penalty is divided into two components: increased parasitic use from the added electrical demand from tower fans and pumps; and the decrease in thermal efficiency from elevated turbine backpressures. Monetizing the energy penalty at PPP requires some assumption as to how the facility will choose to alter its operations to compensate for these changes, if at all. One option would be to accept the reduced amount of revenue-generating electricity available for sale and absorb the economic loss ("production loss option"). A second option would be to increase the firing rate to the turbine (i.e., consume more fuel) and produce the same amount of revenue-generating electricity as had been obtained with the once-through cooling system ("increased fuel option"). The degree to which a facility is able, or prefers, to operate at a higher firing rate, however, produces the more likely scenario—some combination of the two.

Ultimately, the manner in which PPP would alter operations to address efficiency changes is driven by considerations unknown to this study (e.g., corporate strategy, contractual obligations, operating protocols and turbine pressure tolerances). In all summary cost estimates, this study calculates the energy penalty's monetized value by assuming the facility will use the increased fuel option to compensate for reduced efficiency and generate the amount of electricity equivalent to the estimated shortfall. With this option, the energy penalty is equivalent to the financial cost of additional fuel and is nominally less costly than the production loss option. This option, however, may not reflect long-term costs such as increased maintenance or system degradation that may result from continued operation at a higher-than-designed turbine firing rate.[5]

The energy penalty for PPP is calculated by first estimating the increased parasitic demand from the cooling tower pumps and fans, expressed as a percentage of each unit's rated capacity. Likewise, the change in the unit's heat rate is also expressed as a capacity percentage.

4.6.1 INCREASED PARASITIC USE (FANS AND PUMPS)

Depending on ambient conditions or the operating load at a given time, PPP may be able to take one or more cooling tower cells offline and still obtain the required level of cooling. This would also reduce the cumulative electrical demand from the fans. For the purposes of this study, however, operations are evaluated at the design conditions, i.e., full load; no allowance is made

[5] Increasing the thermal load to the turbine will raise the circulating water temperature exiting the condenser. The cooling towers selected for this study are designed with a maximum water return temperature of approximately 120º F. Depending on each unit's operating conditions (i.e., condenser outlet temperature), the degree to which the thermal input to the turbine can be increased may be limited.

for seasonal changes. The increased electrical demand from cooling tower fan operation is summarized in Table L–18.

Table L–18. Cooling Tower Fan Parasitic Use

	Tower 1	Tower 2	PPP total
Units served	Unit 5	Unit 6	--
Generating capacity (MW)	325	325	**650**
Number of fans (one per cell)	12	12	**24**
Motor power per fan (hp)	211	211	--
Total motor power (hp)	2,526	2,526	**5,053**
MW total	1.88	1.88	**3.77**
Fan parasitic use (% of capacity)	**0.58%**	**0.58%**	**0.58%**

Additional circulating water pump capacity for the wet cooling towers will also increase the parasitic electricity usage at PPP. Makeup water will continue to be withdrawn from Suisun Bay with one of the existing circulating water pumps; the remaining pumps will be retired.

The net increase in pump-related parasitic usage is the difference between the new wet cooling tower configuration (new plus retained pumps) and the existing once-through configuration. For calculation purposes, this study assumes full-load operation to estimate the cost of increased parasitic use. Final estimates, therefore, allocate the retained pump's electrical demand to each tower based on the proportion of the facility's generating capacity it services. Operating fewer towers or tower cells will alter the allocation of the retained pump's electrical demand, but not the total demand.

Because one of the main design assumptions maintains the existing flow rate through each condenser, the new circulating pumps are single speed and are assumed to operate at their full rated capacity when in use. The increased electrical demand associated with cooling tower pump operation is summarized in Table L–19.

Table L–19. Cooling Tower Pump Parasitic Use

	Tower 1	Tower 2	PPP total
Units served	Unit 5	Unit 6	--
Generating capacity (MW)	325	325	**650**
Existing pump configuration (hp)	1,200	1,200	**2,400**
New pump configuration (hp)	6,664	6,664	**13,327**
Difference (hp)	5,464	5,464	**10,927**
Difference (MW)	4.1	4.1	**8.1**
Net pump parasitic use (% of capacity)	**1.25%**	**1.25%**	**1.25%**

4.6.2 HEAT RATE CHANGE

Heat rate adjustments were calculated based on each month's ambient climate conditions and reflect the estimated difference between operations with once-through and wet cooling tower systems. As noted above, the energy penalty analysis assumes PPP will increase its fuel consumption to compensate for lost efficiency and the increased parasitic load from fans and pumps. The higher turbine firing rate will increase the thermal load rejected to the condenser, which, in turn, results in a higher backpressure value and corresponding increase in the heat rate. No data are available describing the changes in turbine backpressures above the design thermal loads. For the purposes of monetizing the energy penalty only, this study conservatively assumed an additional increase in the heat rate of 0.5 percent at the higher firing rate; the actual effect at PPP may be greater or less. Changes in the heat rate for each unit at PPP are presented in Figure L–12 and Figure L–13.

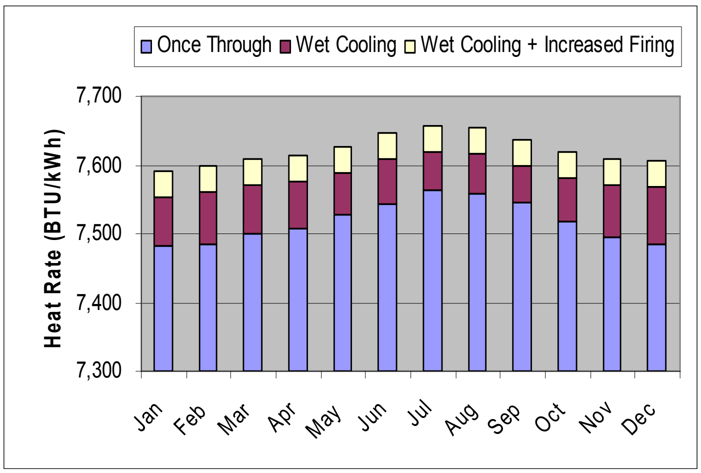

Figure L–12. Estimated Heat Rate Change (Unit 5)

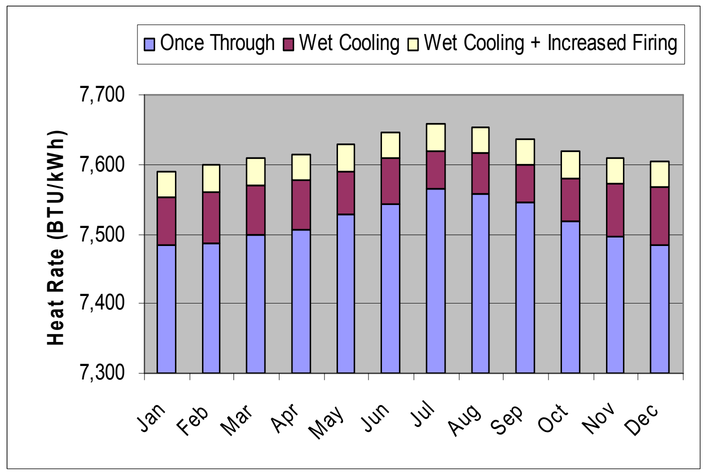

Figure L–13. Estimated Heat Rate Change (Unit 6)

4.6.3 CUMULATIVE ESTIMATE

Using the increased fuel option, the energy penalty's cumulative value is obtained by first calculating the relative costs of generation ($/MWh) for the once-through system and the wet cooling system adjusted for a higher turbine firing rate. The cost of generation for PPP is based on the relative heat rates developed in Section 3.4.5 and the average monthly wholesale natural gas cost ($/MMBTU) (ICE 2006a). The difference between these two values represents the monthly increased cost, per MWh, that results from converting to wet cooling towers. This value is then applied to the net MWh generated for the each month and summed to calculate the annual cost.

Based on 2006 output data, the Year 1 energy penalty for PPP will be approximately $207,000. In contrast, the energy penalty's value calculated with the production loss option would be approximately $660,000. Together, these values represent the range of potential energy penalty costs for PPP. Table L–20 and Table L–21 summarize the energy penalty estimates for each unit using the increased fuel option.

Table L-20. Unit 5 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	7,483	44.90	7,590	45.54	0.64	0	0
February	5.50	7,486	41.17	7,598	41.79	0.62	11,236	6,962
March	4.75	7,499	35.62	7,609	36.14	0.52	13,283	6,920
April	4.75	7,507	35.66	7,615	36.17	0.51	51,821	26,522
May	4.75	7,527	35.75	7,628	36.23	0.48	0	0
June	5.00	7,543	37.72	7,646	38.23	0.52	11,111	5,732
July	6.50	7,564	49.17	7,658	49.78	0.61	55,858	34,014
August	6.50	7,558	49.13	7,654	49.75	0.62	0	0
September	4.75	7,545	35.84	7,637	36.28	0.44	0	0
October	5.00	7,518	37.59	7,618	38.09	0.50	14,319	7,115
November	6.00	7,496	44.98	7,609	45.66	0.68	50,788	34,570
December	6.50	7,484	48.65	7,605	49.43	0.78	2,966	2,328
							Unit 5 total	**124,163**

Table L-21. Unit 6 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	7,483	44.90	7,590	45.54	0.64	0	0
February	5.50	7,486	41.17	7,598	41.79	0.62	15,970	9,895
March	4.75	7,499	35.62	7,609	36.14	0.52	51	27
April	4.75	7,507	35.66	7,615	36.17	0.51	0	0
May	4.75	7,527	35.75	7,628	36.23	0.48	47,074	22,474
June	5.00	7,543	37.72	7,646	38.23	0.52	10,335	5,331
July	6.50	7,564	49.17	7,658	49.78	0.61	74,260	45,220
August	6.50	7,558	49.13	7,654	49.75	0.62	0	0
September	4.75	7,545	35.84	7,637	36.28	0.44	0	0
October	5.00	7,518	37.59	7,618	38.09	0.50	0	0
November	6.00	7,496	44.98	7,609	45.66	0.68	180	123
December	6.50	7,484	48.65	7,605	49.43	0.78	0	0
							Unit 6 total	**83,070**

4.7 NET PRESENT COST

The Net Present Cost (NPC) of a wet cooling system retrofit at PPP is the sum of all annual expenditures over the project's 20-year life span discounted according to the year in which the expense is incurred and the selected discount rate. The NPC represents the total change in revenue streams, in 2007 dollars, that PPP can expect over 20 years as a direct result of converting to wet cooling towers. The following values were used to calculate the NPC at a 7 percent discount rate:

- *Capital and Start-up.* Includes all capital, indirect, contingency, and shutdown costs. All costs in this category are incurred in Year 0. (See Table L–16.)
- *Annual O&M.* Base cost values for Year 1 and Year 12 are adjusted for subsequent years using a 2 percent year-over-year escalator. Because PPP has a relatively low capacity utilization factor, O&M costs for the NPC calculation were estimated at 30 percent of their maximum value. (See Table L–17.)
- *Annual Energy Penalty.* Insufficient information is available to this study to forecast future generating output at PPP. In lieu of annual estimates, this study uses the net MWh output from 2006 as the calculation basis for Years 1 through 20. Wholesale prices include a year-over-year price escalator of 5.8 percent (based on the Producer Price Index). The energy penalty values are based on the increased fuel option discussed in Section 4.6. (See Table L–20 and Table L–21.)

Using these values, the NPC_{20} for PPP is $134 million. Appendix C contains detailed annual calculations used to develop this cost.

4.8 ANNUAL COST

The annual cost incurred by PPP for a wet cooling tower retrofit is the sum of annual amortized capital costs plus the annual average of O&M and energy penalty expenditures. Capital costs are amortized at a 7 percent discount rate over 20 years. O&M and energy penalty costs are calculated in the same manner as for the NPC_{20} (Section 4.7). Revenue losses from a construction-related shutdown, if any, are incurred in Year 0 only and not included in the annual cost summarized in Table L–22.

Table L–22. Annual Cost

Discount rate	Capital Cost ($)	Annual O&M ($)	Annual energy penalty ($)	Annual cost ($)
7.00%	11,800,000	500,000	400,000	**12,700,000**

4.9 COST-TO-GROSS REVENUE COMPARISON

Limited financial data are available to conduct a detailed analysis of the economic impact that a wet cooling system retrofit will have on PPP's annual revenues. The facility's gross annual revenue can be approximated using 2006 net generating data (CEC 2006) and average wholesale prices for electricity as recorded at the SP 15 trading hub (ICE 2006b). This estimate, therefore, does not reflect any changes that may result from different wholesale prices or contract agreements that may increase or decrease the gross revenue summarized below, nor does it account for annual fixed revenue requirements or other variable costs.

The estimate of gross annual revenue from electricity sales at PPP is a straightforward calculation that multiplies the monthly wholesale cost of electricity by the amount generated for the particular month. The estimated gross revenue for PPP is summarized in Table L–23. A comparison of annual costs to annual gross revenue is summarized in Table L–24.

Table L–23. Estimated Gross Revenue

	Wholesale price ($/MWh)	Net generation (MWh)			Estimated gross revenue ($)			
		Unit 5	Unit 6	Unit 7	Unit 5	Unit 6	Unit 7	PPP total
January	66	0	0	0	0	0	0	**0**
February	61	11,236	15,970	0	685,396	974,170	0	**1,659,566**
March	51	13,283	51	0	677,433	2,601	0	**680,034**
April	51	51,821	0	0	2,642,871	0	0	**2,642,871**
May	51	0	47,074	0	0	2,400,774	0	**2,400,774**
June	55	11,111	10,335	35,395	611,105	568,425	1,946,725	**3,126,255**
July	91	55,858	74,260	52,602	5,083,078	6,757,660	4,786,782	**16,627,520**
August	73	0	0	0	0	0	0	**0**
September	53	0	0	0	0	0	0	**0**
October	57	14,319	0	0	816,183	0	0	**816,183**
November	66	50,788	180	0	3,352,008	11,880	0	**3,363,888**
December	67	2,966	0	0	198,722	0	0	**198,722**
PPP total		**211,382**	**147,870**	**87,997**	**14,066,796**	**10,715,510**	**6,733,507**	**31,515,813**

Table L–24. Cost-Revenue Comparison

Estimated gross annual revenue ($)	Initial capital		O&M		Energy penalty		Total annual cost	
	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross
31,500,000	11,800,000	37	500,000	1.6	400,000	1.3	**12,700,000**	**40**

5.0 OTHER TECHNOLOGIES

Within the scope of this study, and using the OPC resolution's stated goal of reducing impingement and entrainment by 90–95 percent as a benchmark, the effectiveness of other technologies commonly used to address such impacts could not be conclusively determined for use at PPP.

Among these technologies, however, and within the framework of this study, fine-mesh wedgewire screens exhibit the greatest potential for successful deployment. A final conclusion as to their applicability will have to be based on a more detailed site-specific investigation of the source water's physical characteristics. A more detailed analysis that also comprises a biological evaluation may determine the applicability of one or more of these technologies to PPP. A brief summary of the applicability of these technologies follows.

5.1 MODIFIED RISTROPH SCREENS—FINE MESH

The principal concern with this technology is the successful return of viable organisms captured on the screens to the source water body. PPP currently withdraws its cooling water through a shoreline CWIS on the southern bank of Suisun Bay. Modifying the existing traveling screens to include fine-mesh panels and a return system would require expanding the existing CWIS and identifying a suitable return location to prevent re-impingement. These modifications, and the potential for success, are plausible but require detailed investigation of the potentially affected species in Suisun Bay before a conclusive determination can be made.

5.2 BARRIER NETS

If impingement is a significant concern at PPP, a barrier net could conceivably be placed in Suisun Bay as an impingement control measure in addition to flow reduction methods. Successful deployment of a barrier net would depend on how far offshore the net would extend and whether this would interfere with the bay's navigational or recreational uses. Debris loadings in the Delta as well as the impact from any storms or tidal movements would also need to be addressed before deployment.

Costs for barrier nets are not significant and depend on the net's size and the amount of maintenance required. Seasonal deployments may be possible, and thereby reduce costs, if migratory patterns in Suisun Bay allow. Based on estimates developed for the Phase II rule, barrier net initial capital costs for PPP range from \$160,000 to \$200,000 with annual O&M costs of approximately \$30,000 to \$40,000 (USEPA 2004). Maintenance costs include replacement of net panels, which can be high depending on the frequency of replacement.

5.3 AQUATIC FILTRATION BARRIERS

An evaluation of an aquatic filtration barrier (AFB) at Mirant's Contra Costa Power Plant was proposed as part of a Habitat Conservation Program for CCPP and PPP. Difficulties pertaining to the AFB's installation and maintenance at one of Mirant's New York facilities precluded a complete evaluation at CCPP. Maintenance concerns were driven by fouling and the inability to maintain a sufficiently clean fabric (Mirant Delta 2006). AFBs have not been demonstrated to be effective in an estuarine environment at the scale necessary for PPP. Any such installation would have to address the potential for high sediment loads and fouling that would adversely affect performance.

5.4 VARIABLE SPEED DRIVES

VSDs are currently installed at PPP, but no information was available to evaluate their use and any relative reductions in impingement or entrainment.

5.5 CYLINDRICAL FINE-MESH WEDGEWIRE

Cylindrical wedgewire screens have been deployed in estuarine settings with physical characteristics similar to those that would be experienced in the Sacramento/San Joaquin Delta. Fine-mesh applications may be susceptible to fouling or clogging due to sediment loads, but may be feasible at PPP.

To function as intended, cylindrical wedgewire screens must be submerged in a water body with a consistent ambient current of 0.5 fps. Ideally, this current is unidirectional so that screens may be oriented properly and any debris impinged on the screens will be carried downstream when the air-burst cleaning system is activated.

Data obtained from USGS stream flow gages for the Sacramento River in the vicinity of PPP show average ambient currents exceed 0.5 fps for more than 95 percent of the time (Figure L–14) (USGS 2007). Prior to screen installation, more accurate current measurements in the precise screen location would have to taken.

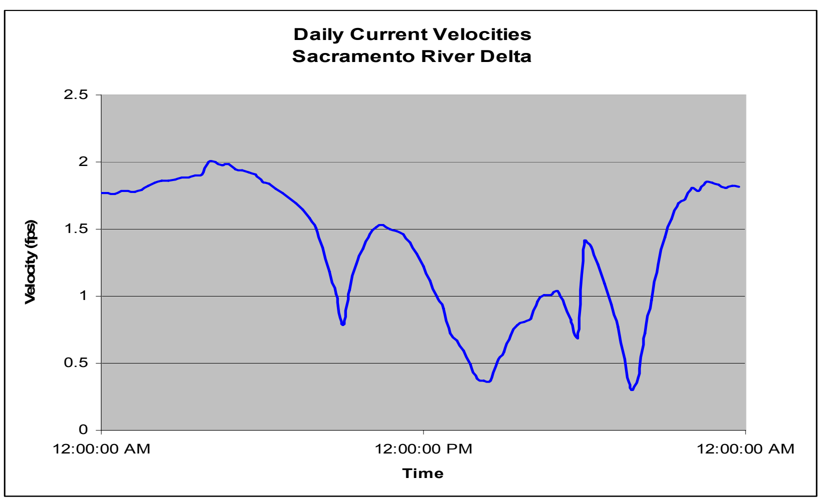

Figure L–14. Diurnal Sacramento River Currents

Based on the limited data available, a conceptual plan and cost for fine-mesh wedgewire screens was developed for an installation at PPP. Fine-mesh wedgewire screens for PPP would be installed offshore in Suisun Bay approximately 800 feet north of the Unit 5 and 6 CWIS. This location is deep enough for five 84-inch diameter screen assemblies; shoreline or bulkhead wall placement would require dredging in front of the intake, dismantling the dock and continued maintenance to prevent sediment buildup. The screens' general placement at PPP is shown in Figure L–15. Approximate costs are summarized in Table L–25.

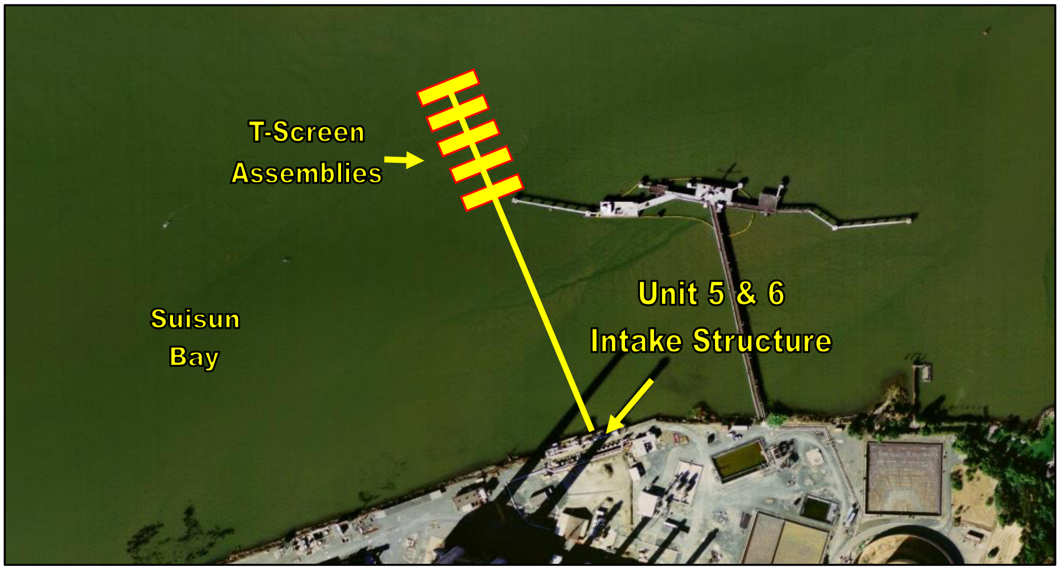

Figure L–15. Approximate Cylindrical Wedgewire Screen Location

Table L–25. Estimated Cost of Fine-Mesh Wedgewire Screens

	Installed cost ($)
5 T-screens (84" x 300")	1,940,000
Piping (120")	4,000,000
Indirect / contingency	891,000
PPP total	**6,831,000**

(a) T-screen cost includes air-burst cleaning system (GLV 2007).
(b) PCCP piping costs based on vendor price quotes and installation estimates for 120" pipe used in this study. Underwater installation costs may vary.

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Appendix A. Once-Through and Closed-Cycle Thermal Performance

		Unit 5			Unit 5		
		Once through	Closed cycle	Net increase	Once through	Closed cycle	Net increase
JAN	Backpressure (in. HgA)	1.05	1.87	**0.82**	1.05	1.87	**0.82**
	Heat rate Δ (%)	*-0.36*	*0.57*	***0.93***	*-0.36*	*0.57*	***0.93***
FEB	Backpressure (in. HgA)	1.16	1.93	**0.77**	1.16	1.93	**0.77**
	Heat rate Δ (%)	*-0.33*	*0.67*	***1.00***	*-0.33*	*0.67*	***1.00***
MAR	Backpressure (in. HgA)	1.38	2.00	**0.62**	1.38	2.00	**0.62**
	Heat rate Δ (%)	*-0.15*	*0.81*	***0.96***	*-0.15*	*0.81*	***0.96***
APR	Backpressure (in. HgA)	1.47	2.05	**0.57**	1.47	2.05	**0.57**
	Heat rate Δ (%)	*-0.04*	*0.89*	***0.93***	*-0.04*	*0.89*	***0.93***
MAY	Backpressure (in. HgA)	1.66	2.14	**0.48**	1.66	2.14	**0.48**
	Heat rate Δ (%)	*0.23*	*1.06*	***0.83***	*0.23*	*1.06*	***0.83***
JUN	Backpressure (in. HgA)	1.79	2.28	**0.49**	1.79	2.28	**0.49**
	Heat rate Δ (%)	*0.44*	*1.31*	***0.87***	*0.44*	*1.31*	***0.87***
JUL	Backpressure (in. HgA)	1.96	2.37	**0.41**	1.96	2.37	**0.41**
	Heat rate Δ (%)	*0.73*	*1.47*	***0.74***	*0.73*	*1.47*	***0.74***
AUG	Backpressure (in. HgA)	1.91	2.33	**0.43**	1.91	2.33	**0.43**
	Heat rate Δ (%)	*0.64*	*1.41*	***0.77***	*0.64*	*1.41*	***0.77***
SEP	Backpressure (in. HgA)	1.80	2.21	**0.41**	1.80	2.21	**0.41**
	Heat rate Δ (%)	*0.46*	*1.19*	***0.73***	*0.46*	*1.19*	***0.73***
OCT	Backpressure (in. HgA)	1.59	2.07	**0.48**	1.59	2.07	**0.48**
	Heat rate Δ (%)	*0.11*	*0.93*	***0.82***	*0.11*	*0.93*	***0.82***
NOV	Backpressure (in. HgA)	1.35	2.01	**0.66**	1.35	2.01	**0.66**
	Heat rate Δ (%)	*-0.19*	*0.82*	***1.01***	*-0.19*	*0.82*	***1.01***
DEC	Backpressure (in. HgA)	1.12	1.98	**0.85**	1.12	1.98	**0.85**
	Heat rate Δ (%)	*-0.34*	*0.76*	***1.10***	*-0.34*	*0.76*	***1.10***

Note: Heat rate delta represents change from design value calculated according to estimated ambient conditions for each month.

Appendix B. Itemized Capital Costs

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
CIVIL / STRUCTURAL / PIPING	--	--	--	--	--	--	--	--	--	--
Allocation for other accessories (bends, water hammers…)	lot	1	--	--	500,000	500,000	4,000.00	95	380,000	**880,000**
Allocation for pipe racks (approx 800 ft) and cable racks	t	80	--	--	2,500	200,000	17.00	105	142,800	**342,800**
Allocation for sheet piling and dewatering	lot	1	--	--	500,000	500,000	5,000.00	100	500,000	**1,000,000**
Allocation for testing pipes	lot	1	--	--	--	--	2,000.00	95	190,000	**190,000**
Allocation for Tie-Ins to existing condenser's piping	lot	1	--	--	250,000	250,000	2,000.00	95	190,000	**440,000**
Allocation for trust blocks	lot	1	--	--	50,000	50,000	500.00	95	47,500	**97,500**
Backfill for PCCP pipe (reusing excavated material)	m3	52,725	--	--	--	--	0.04	200	421,800	**421,800**
Bedding for PCCP pipe	m3	7,985	--	--	40	319,400	0.04	200	63,880	**383,280**
Bend for PCCP pipe 30" & 36" diam (allocation)	ea	40	--	--	5,000	200,000	25.00	95	95,000	**295,000**
Bend for PCCP pipe 72" diam (allocation)	ea	20	--	--	18,000	360,000	40.00	95	76,000	**436,000**
Bend for PCCP pipe 84" diam (allocation)	ea	150	--	--	20,000	3,000,000	50.00	95	712,500	**3,712,500**
Building architectural (siding, roofing, doors, painting…etc)	ea	2	--	--	250,000	500,000	3,000.00	82	492,000	**992,000**
Butterfly valves 24" c/w allocation for actuator & air lines	ea	4	28,000	112,000	--	--	50.00	95	19,000	**131,000**
Butterfly valves 30" c/w allocation for actuator & air lines	ea	28	30,800	862,400	--	--	50.00	95	133,000	**995,400**
Butterfly valves 60" c/w allocation for actuator & air lines	ea	4	75,600	302,400	--	--	60.00	95	22,800	**325,200**
Butterfly valves 72" c/w allocation for actuator & air lines	ea	20	96,600	1,932,000	--	--	75.00	95	142,500	**2,074,500**
Butterfly valves 84" c/w allocation for actuator & air lines	ea	12	124,600	1,495,200	--	--	75.00	95	85,500	**1,580,700**
Check valves 30"	ea	4	44,000	176,000	--	--	16.00	95	6,080	**182,080**
Check valves 60"	ea	4	108,000	432,000	--	--	30.00	95	11,400	**443,400**
Concrete basin walls (all in)	m3	350	--	--	250	87,500	8.00	82	229,600	**317,100**
Concrete elevated slabs (all in)	m3	538	--	--	275	147,950	10.00	82	441,160	**589,110**
Concrete for transformers and oil catch basin (allocation)	m3	200	--	--	275	55,000	10.00	82	164,000	**219,000**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Concrete slabs on grade (all in)	m3	2,730	--	--	220	600,600	4.00	82	895,440	**1,496,040**
Ductile iron cement pipe 12" diam. for fire water line	ft	4,000	--	--	100	400,000	0.60	95	228,000	**628,000**
Excavation and backfill for fire line & make-up (using excavated material for backfill except for bedding)	m3	16,437	--	--	--	--	0.08	200	262,992	**262,992**
Excavation for PCCP pipe	m3	84,245	--	--	--	--	0.04	200	673,960	**673,960**
Fencing around transformers	m	50	--	--	33	1,650	1.00	82	4,100	**5,750**
Flange for PCCP joints 30"	ea	24	--	--	2,260	54,240	16.00	95	36,480	**90,720**
Flange for PCCP joints 72"	ea	8	--	--	9,860	78,880	25.00	95	19,000	**97,880**
Flange for PCCP joints 84"	ea	16	--	--	13,210	211,360	30.00	95	45,600	**256,960**
Foundations for pipe racks and cable racks	m3	190	--	--	275	52,250	8.00	82	124,640	**176,890**
FRP flange 24"	ea	8	--	--	1,419	11,352	40.00	95	30,400	**41,752**
FRP flange 30"	ea	88	--	--	1,679	147,765	50.00	95	418,000	**565,765**
FRP flange 60'	ea	16	--	--	7,785	124,565	100.00	95	152,000	**276,565**
FRP flange 72"	ea	40	--	--	20,888	835,507	200.00	95	760,000	**1,595,507**
FRP flange 84"	ea	8	--	--	33,381	267,048	300.00	95	228,000	**495,048**
FRP pipe 24" diam.	ft	600	--	--	95	56,760	0.30	95	17,100	**73,860**
FRP pipe 60" diam.	ft	160	--	--	615	98,384	0.90	95	13,680	**112,064**
FRP pipe 84" diam.	ft	1,200	--	--	946	1,135,200	1.50	95	171,000	**1,306,200**
FRP pipe 96" diam.	ft	200	--	--	2,838	567,600	1.75	95	33,250	**600,850**
Harness clamp 30" & 36"c/w internal testable joint	ea	220	--	--	2,000	440,000	16.00	95	334,400	**774,400**
Harness clamp 72" c/w internal testable joint	ea	100	--	--	2,440	244,000	18.00	95	171,000	**415,000**
Harness clamp 84" c/w internal testable joint	ea	800	--	--	2,845	2,276,000	20.00	95	1,520,000	**3,796,000**
Joint for FRP pipe 24" diam.	ea	20	--	--	901	18,012	35.00	95	66,500	**84,512**
Joint for FRP pipe 84" diam.	ea	40	--	--	5,014	200,552	300.00	95	1,140,000	**1,340,552**
Joint for FRP pipe 60" diam.	ea	8	--	--	1,797	14,379	100.00	95	76,000	**90,379**
Joint for FRP pipe 96" diam.	ea	10	--	--	17,974	179,740	600.00	95	570,000	**749,740**
PCCP pipe 30" dia. for make-up	ft	4,000	--	--	125	500,000	0.70	95	266,000	**766,000**
PCCP pipe 72" diam.	ft	1,600	--	--	507	811,200	1.30	95	197,600	**1,008,800**
PCCP pipe 84" diam.	ft	15,200	--	--	562	8,542,400	1.50	95	2,166,000	**10,708,400**
Riser (FRP pipe 30" diam X55 ft)	ea	24	--	--	15,350	368,400	150.00	95	342,000	**710,400**
Structural backfill under towers & pump houses	m3	90,000	--	--	15	1,350,000	0.06	82	442,800	**1,792,800**
Structural steel for building	t	320	--	--	2,500	800,000	20.00	105	672,000	**1,472,000**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
CIVIL / STRUCTURAL / PIPING TOTAL	--	--	--	**5,312,000**	--	**26,557,694**	--	--	**16,644,462**	**48,514,156**
ELECTRICAL	--	--	--	--	--	--	--	--	--	--
4.16 kv cabling feeding MCC's	m	1,500	--	--	75	112,500	0.40	110	66,000	**178,500**
4.16kV switchgear - 4 breakers	ea	1	250,000	250,000	--	--	150.00	110	16,500	**266,500**
460 volt cabling feeding MCC's	m	1,000	--	--	70	70,000	0.40	110	44,000	**114,000**
480V Switchgear - 1 breaker 3000A	ea	6	30,000	180,000	--	--	80.00	110	52,800	**232,800**
Allocation for automation and control	lot	1	--	--	1,000,000	1,000,000	10,000.00	110	1,100,000	**2,100,000**
Allocation for cable trays and duct banks	m	1,500	--	--	75	112,500	1.00	110	165,000	**277,500**
Allocation for lighting and lightning protection	lot	1	--	--	150,000	150,000	1,500.00	110	165,000	**315,000**
Dry Transformer 2MVA xxkV-480V	ea	6	100,000	600,000	--	--	100.00	110	66,000	**666,000**
Lighting & electrical services for pump house building	ea	4	--	--	20,000	80,000	250.00	110	110,000	**190,000**
Local feeder for 200 HP motor 460 V (up to MCC)	ea	24	--	--	18,000	432,000	150.00	110	396,000	**828,000**
Local feeder for 4000 HP motor 4160 V (up to MCC)	ea	4	--	--	50,000	200,000	200.00	110	88,000	**288,000**
Oil Transformer 10/13.33MVA xx-4.16kV	ea	2	190,000	380,000	--	--	150.00	110	33,000	**413,000**
Primary breaker(xxkV)	ea	4	45,000	180,000	--	--	60.00	110	26,400	**206,400**
Primary feed cabling (assumed 13.8 kv)	m	3,000	--	--	175	525,000	0.50	110	165,000	**690,000**
ELECTRICAL TOTAL	--	--	--	**1,590,000**	--	**2,682,000**	--	--	**2,493,700**	**6,765,700**
MECHANICAL	--	--	--	--	--	--	--	--	--	--
Allocation for ventilation of buildings	ea	2	100,000	200,000	--	--	1,000.00	95	190,000	**390,000**
Cooling tower for unit 5	lot	1	6,800,000	6,800,000	--	--	--	--	--	**6,800,000**
Cooling tower for unit 6	lot	1	6,800,000	6,800,000	--	--	--	--	--	**6,800,000**
Overhead crane 50 ton in (in pump house) Including additional structure to reduce the span	ea	2	500,000	1,000,000	--	--	1,000.00	95	190,000	**1,190,000**
Pump 4160 V 4000 HP	ea	4	1,600,000	6,400,000	--	--	800.00	95	304,000	**6,704,000**
MECHANICAL TOTAL	--	--	--	**21,200,000**	--	**0**	--	--	**684,000**	**21,884,000**

Appendix C. Net Present Cost Calculation

Project year	Capital/start-up ($)	O & M ($)	Energy penalty ($)		Total ($)	Annual discount factor	Present value ($)
			Unit 1	Unit 2			
0	125,400,000	--	--	--	125,400,000	1	125,400,000
1	--	385,200	124,162	83,069	592,430	0.9346	553,685
2	--	392,904	131,400	87,912	612,216	0.8734	534,709
3	--	400,762	139,061	93,037	632,860	0.8163	516,603
4	--	408,777	147,168	98,461	654,406	0.7629	499,247
5	--	416,953	155,748	104,201	676,902	0.713	482,631
6	--	425,292	164,828	110,276	700,396	0.6663	466,674
7	--	433,798	174,438	116,705	724,941	0.6227	451,420
8	--	442,474	184,607	123,509	750,590	0.582	436,843
9	--	451,323	195,370	130,710	777,403	0.5439	422,829
10	--	460,350	206,760	138,330	805,440	0.5083	409,405
11	--	469,557	218,814	146,395	834,765	0.4751	396,597
12	--	569,711	231,571	154,929	956,211	0.444	424,558
13	--	581,105	245,072	163,962	990,138	0.415	410,907
14	--	592,727	259,359	173,521	1,025,607	0.3878	397,730
15	--	604,582	274,480	183,637	1,062,699	0.3624	385,122
16	--	616,673	290,482	194,343	1,101,498	0.3387	373,078
17	--	629,007	307,417	205,673	1,142,097	0.3166	361,588
18	--	641,587	325,340	217,664	1,184,591	0.2959	350,520
19	--	654,419	344,307	230,354	1,229,079	0.2765	339,840
20	--	667,507	364,380	243,784	1,275,670	0.2584	329,633
Total							**133,943,619**

M. REDONDO BEACH GENERATING STATION

AES REDONDO BEACH, LLC—REDONDO BEACH, CA

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1.0 GENERAL SUMMARY

Converting the existing once-through cooling systems at Redondo Beach Generating Station (RBGS) to wet cooling towers is technically feasible within the current boundaries of the station, but zoning constraints and proposed redevelopment plans by the City of Redondo Beach create significant obstacles that are unlikely to permit constructing four large wet cooling towers at the site.

In 2002 the City of Redondo Beach adopted the “Heart of the City” Specific Plan following a memorandum of understanding between AES Redondo Beach and the city that outlined possible plans of redeveloping and downsizing the existing site (Figure M−1). The Heart of the City plan calls for comprehensive redevelopment of the King Harbor area by improving access to the marina and creating a “Village Core” that would consist of small commercial shops and residential areas. Prominent pedestrian access areas would include pathways to the marina across a portion of the existing AES site. Voter disapproval led to the plan’s rescission and replacement with a “Heart Park” that would revitalize wetlands and preserve open space in the area, although there has been no agreement to proceed at the site.

The final redevelopment vision of the existing location is not clear, but the intent of both the city and the voters appears to favor a transition away from expanded industrial use of the area. Even without a comprehensive development plan in place, the existing site’s configuration and its proximity to commercial and residential areas present substantial obstacles for conformance with land use plans and zoning ordinances.

For these reasons, this study did not conduct a detailed evaluation of wet cooling towers for RBGS.

Figure M−1. General Vicinity of Redondo Beach Generating Station

2.0 BACKGROUND

RBGS currently operates 4 steam generating units (Units 5–8) on approximately x acres in the city of Redondo Beach, Los Angeles County, owned and operated by AES Redondo Beach, LLC. Four other steam units (Units 1-4 have been retired but remain on the facility property. Units at RBGS are used infrequently, with the 2006 combined capacity utilization rate equaling 5 percent.

Table M–1. General Information

Unit	In-service year	Rated capacity (MW)	2006 capacity utilization [a]	Condenser cooling water flow (gpm)
Unit 5	1954	175	1.7%	72,000
Unit 6	1957	175	1.7%	72,000
Unit 7	1967	480	6.7%	234,000
Unit 8	1967	480	5.6%	234,000
RBGS total		**1,310**	**5.0 %**	**612,000**

[a] Quarterly Fuel and Energy Report—2006 (CEC 2006).

Figure M–2. Site View

2.1 COOLING WATER SYSTEM

Cooling water for Units 5 and 6 is withdrawn through two submerged conduits extending into King Harbor and the Redondo Beach Marina. The submerged end of each is fitted with a velocity cap that redirects the intake flow and triggers a flight response in motile fish. The onshore portion of the intake consists of trash racks and vertical traveling screens. The four traveling screens (two per unit) are fitted with 5/8-inch wire mesh panels that are rotated automatically based on the pressure differential between screen's upstream and downstream faces (12 inches). A high-pressure spray removes any debris impinged on the screens, including any fish, for disposal at a landfill. Unit 5 is serviced by two circulating water pumps rated at 38,000 gallons per minute (gpm), for a total capacity of 76,000 gpm, or 110 million gallons per day (mgd). Unit 6 is serviced by two pumps rated at 37,000 gpm, for a total capacity of 74,000 gpm, or 106 mgd (AES 2005).

Cooling water for Units 7 and 8 is withdrawn through a submerged conduit that extends approximately 3,000 feet from the facility and is located between the constructed breakwaters that form the entrance to King Harbor. The submerged end of the conduit is fitted with a velocity cap that redirects the intake flow and triggers a flight response in motile fish. The onshore portion of the intake consists of trash racks and vertical traveling screens. The four traveling screens (two per unit) are fitted with 5/8-inch wire mesh panels that are rotated automatically based on the pressure differential between screen's upstream and downstream faces (9 inches). Each unit is serviced by two circulating water pumps, two per unit, each rated at 117,000 gpm, or 169 mgd, for a total capacity of 468,000 gpm, or 674 mgd.

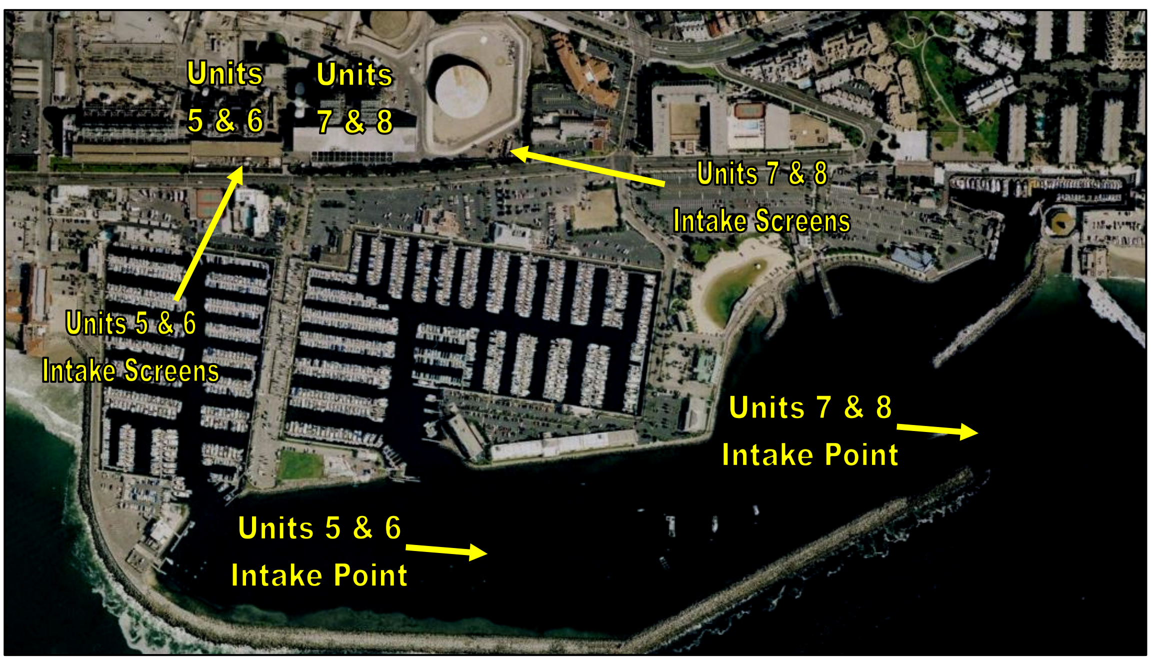

Figure M–3. Intake Locations

2.2 SECTION 316(B) PERMIT COMPLIANCE

Each CWIS currently in operation at RBGS uses a velocity cap to reduce the entrainment of motile fish through the system, although it is commonly thought of as an impingement reduction technology because it targets larger organisms. Velocity caps have been shown to reduce impingement rates when compared with a shoreline intake structure. Likewise, the location of the intake structure in an offshore setting may contribute to lower rates of entrainment when compared with a shoreline intake if the near-shore environment is more biologically productive. This study did not evaluate the effectiveness of either measure.

LARWQCB Order 00-085, adopted in 2000, states the following:

> SCE [Southern California Edison, previous owner]conducted a study (completed in 1982) that addressed the important ecological and engineering factors specified in Section 316(b) guidelines. The study demonstrated that the ecological impacts of the intake system are environmentally acceptable, and provided sufficient evidence that no modification for the location, design, construction or capacity of the existing systems was required. The design, construction and operation of the intake structures was then considered Best Available Technology Economically Achievable (BAT) (sic) as required by Section 316(b) of the Clean Water Act. (LARWQCB 2000, Finding 9)

The order does not contain any numeric or narrative limitations regarding impingement or entrainment resulting from CWIS operation, but does require bimonthly monitoring of impingement at each intake structure (coinciding with scheduled heat treatments). Based on the record available for review, RBGS has been compliant with this permit requirement.

The LARWQCB has notified RBGS of its intent to revisit requirements under CWA Section 316(b), including a determination of the best technology available (BTA) for minimization of adverse environmental impact, during the current permit reissuance process. A final decision regarding any Section 316(b)–related requirements has not been made as of the publication of this study.

3.0 WET COOLING SYSTEM RETROFIT

As noted above, wet cooling towers could be constructed at the current RBGS site, but zoning and local use constraints likely preclude this option. The two most immediate limits concern visible plume and noise.

The site's proximity to existing and future developments, both commercial and residential, would likely require any wet cooling tower to use plume abatement technologies. These towers would occupy a larger footprint than conventional towers and can be taller by 15 feet or more, depending on the various design elements. Furthermore, noise abatement measures would be required, although no measures may be reasonable available that will enable any tower to comply with local noise limitations (55 dBA during daylight hours) given the proximity of nearby office buildings (Figure M–4).

To provide sufficient cooling for the four active units, four cooling towers would be required. For Units 5 and 6, each tower would comprise approximately five 58-foot tall cells with a total length of 240 feet. The towers for Units 7 and 8 would be even longer, approximately 960 feet each, and be located less than 100 feet from the office building shown in Figure M–4. Splitting each tower into multiple arrays may allow for a different configuration and mitigate some of the impacts, but conflicts will remain regardless of the area selected for their placement.

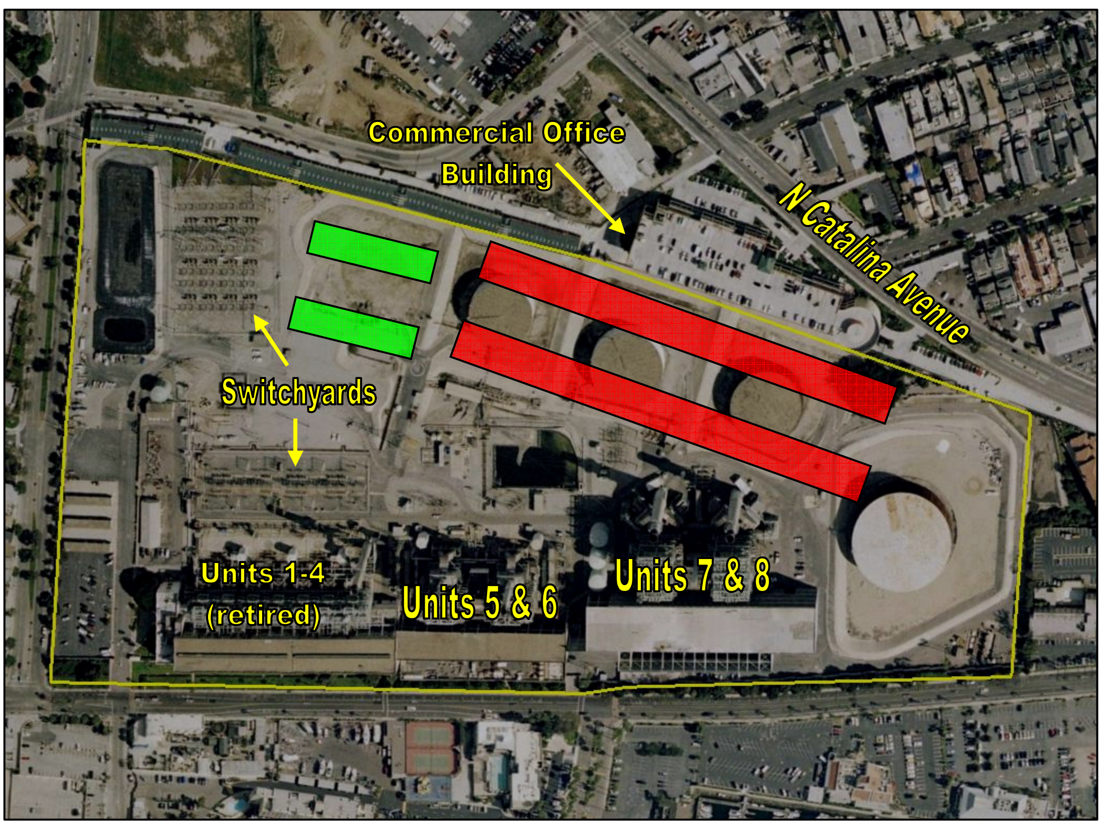

Figure M–4. Hypothetical Location of Cooling Towers

4.0 OTHER TECHNOLOGIES

Within the scope of this study, and using the OPC resolution's stated goal of reducing impingement and entrainment by 90–95 percent as a benchmark, the effectiveness of other technologies commonly used to address such impacts could not be conclusively determined for use at RBGS. As with many existing facilities, the location and configuration of the site complicates the use of some technologies that might be used successfully elsewhere. A more detailed analysis that also comprises a biological evaluation may determine the applicability of one or more of these technologies to RBGS. A brief summary of the applicability of these technologies follows.

4.1 MODIFIED RISTROPH SCREENS—FINE MESH

The principal concern with this technology is the successful return of viable organisms captured on the screens to the source water body. RBGS currently withdraws its cooling water through submerged conduits that extend 2,000 to 3,000 feet from the intake screens at the facility. Reconfiguring the intake structure to place the screens closer to the shoreline is impractical given the developed nature of the area (Redondo Beach Marina). The potential use of fine-mesh screens at RBGS would be dependent upon a biological evaluation that assessed whether impinged organisms could be successfully returned to either King Harbor or Santa Monica Bay and remain viable.

4.2 BARRIER NETS

Barrier nets may prove successful at RBGS in reducing impingement mortality, but their location within the marina or at the entrance to the harbor is infeasible because of the likely interference with recreational and commercial boating.

4.3 AQUATIC FILTRATION BARRIERS

Aquatic filtration barriers (AFBs) are subject to the same siting restrictions as barrier nets.

4.4 VARIABLE SPEED DRIVES

Variable speed drives (VSDs) were not considered for analysis at RBGS because the technology alone cannot be expected to achieve the desired level of reductions in impingement and entrainment, nor could it be combined with another technology to yield the desired reductions. Pumps that have been retrofitted with VSDs can reduce overall flow intake volumes by 10 to 50 percent over the current once-through configuration (USEPA 2001). The actual reduction, however, will vary based on the cooling water demand at different times of the year. At peak demand, the pumps will essentially function as standard circulating water pumps and withdraw water at the maximum rated capacity, thus negating any potential benefit. Use of VSDs may be an economically desirable option when pumps are retrofitted or replaced for other reasons, but VSDs were not considered further for this study.

4.5 CYLINDRICAL FINE-MESH WEDGEWIRE

Fine-mesh cylindrical wedgewire screens have not been deployed or evaluated at open coastal facilities for applications as large as would be required at RBGS (approximately 900 mgd). To function as intended, cylindrical wedgewire screens must be submerged in a water body with a consistent ambient current of 0.5 fps. Ideally, this current would be unidirectional so that screens may be oriented properly and any debris impinged on the screens will be carried downstream when the airburst cleaning system is activated.

Fine-mesh wedgewire screens for RBGS would be located offshore in the Pacific Ocean, west of the facility. Limited information regarding the subsurface currents in the near-shore environment near RBGS is available. Data suggest that these currents are multidirectional depending on the tide and season and fluctuate in terms of velocity, with prolonged periods below 0.5 fps (SCCOOS 2006). To attain sufficient depth (approximately 20 feet) and an ambient current that might allow deployment, screens would need to be located 2,000 feet or more offshore. Discussions with vendors who design these systems indicated that distances more than 1,000 to 1,500 feet become problematic due to the inability of the airburst system to maintain adequate pressure for sufficient cleaning (Someah 2007). Together, these considerations preclude further evaluation of fine-mesh cylindrical wedgewire screens at RBGS.

5.0 REFERENCES

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N. San Onofre Nuclear Generating Station

Southern California Edison—San Clemente, CA

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1.0 GENERAL SUMMARY

Retrofitting the existing once-through cooling system at San Onofre Nuclear Generating Station (SONGS) with closed-cycle wet cooling towers is technically and logistically feasible based on this study's design criteria, and will reduce cooling water withdrawals from the Pacific Ocean by approximately 95 percent. Impingement and entrainment impacts would be reduced by a similar proportion.

The site's location alongside San Onofre State Beach and parallel to the San Diego Freeway would likely require plume-abated cooling towers to prevent public safety hazards on the freeway. The preferred option selected for SONGS includes two cooling tower complexes (one per unit), each comprising six plume-abated wet cooling towers.

Construction-related shutdowns are estimated to take approximately 8 months for both units (concurrent). As a baseload facility, SONGS would incur a substantial financial loss as a result. The configuration of SONGS might enable a staggered retrofit (one unit at a time), which will reduce the amount of generating capacity removed from the grid during construction. As a nuclear facility, SONGS is subject to the Nuclear Regulatory Commission's (NRC) oversight and approval for substantial changes to the existing system operations as described in this chapter. It is unclear how the NRC's review and approval process might affect any downtime estimates.

The cooling tower configuration designed under the preferred option complies with all identified local use restrictions and includes necessary mitigation measures, where applicable.

1.1 COST

Initial capital and Net Present Cost (NPC) costs associated with the installation and operation of wet cooling towers at SONGS are summarized in Table N–1. Annualized costs based on 20-year average values for the various cost elements are summarized in Table N–2. A detailed cost analysis is presented in Section 4.0 of this chapter.

Table N–1. Cumulative Cost Summary

Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Total capital and start-up [a]	593,100,000	30.04	35
NPC_{20} [b]	2,620,900,000	132.74	153

[a] Includes all costs associated with the construction and installation of cooling towers and shutdown loss. The loss of revenue from shutdown is estimated to be $595 million.

[b] NPC_{20} includes all capital costs, operation and maintenance costs, and energy penalty costs over 20 years, discounted at 7.0 percent.

Table N–2. Annual Cost Summary

Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Initial capital [a]	56,000,000	2.84	3.27
Operations and maintenance	8,400,000	0.43	0.49
Energy penalty	144,500,000	7.32	8.43
Total SONGS annual cost	**208,900,000**	**10.59**	**12.19**

[a] Does not include revenue loss associated with shutdown, which is incurred in Year 0 only. The loss of revenue from shutdown is estimated to be $595 million.

1.2 ENVIRONMENTAL

Environmental changes associated with the conversion of the existing once-through cooling system at SONGS to a wet cooling tower system are summarized in Table N–3 and discussed further in Section 3.4 of this chapter.

Table N–3. Environmental Summary

		Unit 2	Unit 3
Water use	Design intake volume (gpm)	795,600	795,600
	Cooling tower makeup water (gpm)	38,200	38,200
	Reduction from capacity (%)	95	95
Energy efficiency	Summer heat rate increase (%)	3.74	3.74
	Summer energy penalty (%)	6.33	6.33
	Annual heat rate increase (%)	2.88	2.88
	Annual energy penalty (%)	5.48	5.48
Direct air emissions [a]	PM_{10} emissions (tons/yr) (maximum capacity)	458	458
	PM_{10} emissions (tons/yr) (2006 capacity utilization)	397	363

[a] Does not include stack emissions from sources used to supplement the projected generation shortfall, if obtained from fossil fuel facilities.

1.3 OTHER POTENTIAL FACTORS

Considerations outside this study's scope may limit the practicality or overall feasibility of a wet cooling tower retrofit at San Onofre.

The Unit 3 tower complex will require new or amended development permits for a coastal bluff that extends several thousand feet south of the facility's current boundary. Use of this area may be restricted due to conflicts with Coastal Act provisions that protect critical habitats along the coastal bluff. In developing size and cost estimates for the Unit 3 tower complex, this study assumes the availability of this area. In the event this area is not available, the goal of retrofitting the Unit 3 cooling system with wet cooling towers becomes infeasible due to the lack of sufficient space.

The construction-related downtime required to complete a cooling system retrofit at SONGS is estimated to be approximately 6 months per unit, during which time either Unit 2 or Unit 3 would not be available to generate electricity. The net impact is the temporary removal of 1,127 MWe from the grid.

2.0 BACKGROUND

SONGS is a nuclear-powered steam electric generating facility 2.5 miles south of the city of San Clemente at the northern edge of San Diego County and is principally owned and operated by Southern California Edison (SCE). The facility's main portion is located south of San Onofre State Beach alongside the Pacific Ocean on land leased from the U.S. Marine Corps' Camp Pendleton. The San Diego Freeway (I-5) parallels the eastern boundary of this section (Figure N–1). SCE operates two pressurized water reactor (PWR) units (Unit 2 and Unit 3), each rated at 1,127 MW, for a facility total of 2,254 MW. Unit 1, also a PWR unit, ceased commercial operation in 1992 and is in the latter stages of decommissioning. The total size of this area is approximately 84 acres. (See Table N–4.)

The SONGS facility also comprises an additional area, roughly 130 acres in size, on the eastern side of the San Diego Freeway. This area, referred to as the Mesa Complex, is also leased from Camp Pendleton and houses various administrative, maintenance, and support services for the facility. No power-generating activities occur at the Mesa Complex.

Table N–4. General Information

Unit	In-service year	Rated capacity (MW)	5-year capacity utilization [a]	Condenser cooling water flow (gpm)
Unit 2	1983	1,127	86.8%	795,600
Unit 3	1984	1,127	79.4%	795,600
SONGS total		**2,254**	**83.1%**	**1,591,200**

[a] A 5-year average capacity utilization factor is used for SONGS because 2006 output (68 percent) was substantially less than in preceding years. As a baseload facility, SONGS can be expected to operate at a higher utilization rate on average. Data were compiled from the Quarterly Fuel and Energy Report (2001–2006) published by the California Energy Commission (CEC 2001–2006).

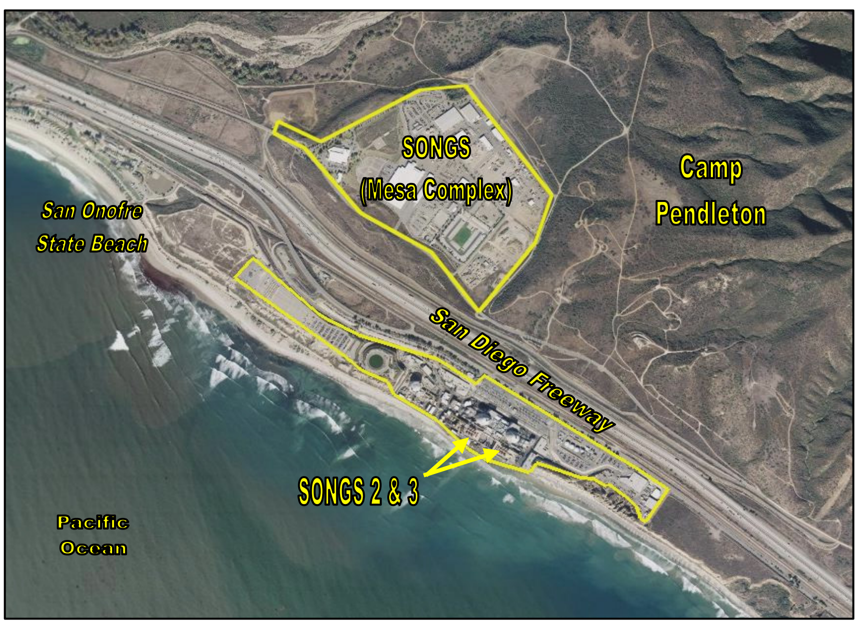

Figure N–1. San Onofre Nuclear Generating Station and Vicinity

2.1 COOLING WATER SYSTEM

SONGS operates two independent cooling water intake structures (CWISs) to provide condenser cooling water to Unit 2 and Unit 3. Once-through cooling water is combined with low-volume wastes generated by SONGS and discharged through two outfalls located 8,300 feet (Unit 2) and 5,900 feet (Unit 3) offshore in the Pacific Ocean. Surface water withdrawals and discharges for each unit are regulated by individual National Pollutant Discharge Elimination System (NPDES) permits CA0108073 for Unit 2; CA0108181 for Unit 3. Each permit is implemented by separate orders administered by the San Diego Regional Water Quality Control Board (SDRWQCB): R9-2005-0005 for Unit 2; R9-2005-0006 for Unit 3. The NPDES permit for Unit 1, which no longer produces wastewaters related to power generation, has been allowed to expire. Any remaining wastewaters produced at the Unit 1 site as a result of the decommissioning process are routed to the Unit 2 or Unit 3 outfalls and discharged under the respective permits.

Figure N–2. Site View of Oceanside Complex

Cooling water for Unit 2 and Unit 3 is withdrawn through two separate submerged conduits, each extending 3,183 feet offshore in the Pacific Ocean and terminating at an approximate depth of 32 feet. The submerged end of the conduit is fitted with a velocity cap to minimize the entrainment of motile fish into the system by converting the vertical flow to a lateral flow, thus triggering a flight response from fish.

The onshore portion of each intake consists of six vertical traveling screens fitted with 3/8-inch mesh panels. Screens are typically rotated based on the pressure differential between the upstream and downstream faces of the screen, although screens may also be rotated manually. A high-pressure spray removes any debris or fish that have become impinged on the screen face.

Captured debris is collected in a dumpster for disposal at a landfill. The through-screen velocity of water is 2.8 feet per second (fps). The vertical traveling screen assemblies are angled approximately 30o to the incoming flow that, combined with a series of vertical louvers placed in the forebay, guides fish to a quiet zone at the far end of the CWIS. A fish elevator periodically empties captured fish into a 4-foot-diameter conduit that returns them by gravity flow to a submerged location approximately 1,900 feet offshore.

Downstream of the six intake screens are four circulating water pumps, each rated at 207,000 gallons per minute (gpm), or 298 million gallons per day (mgd). Each unit has a design pump capacity totaling 828,000 gpm, or 1,192 mgd, for a facility total of 1,656,000 gpm, or 2,384 mgd. A portion of the intake flow is used for the saltwater cooling system (SWCS), which removes heat from auxiliary reactor systems and the turbine plant. Water for the SWCS is withdrawn from and returned to the main condenser flow.

2.2 SECTION 316(B) PERMIT COMPLIANCE

The CWIS currently in operation at SONGS uses velocity caps to reduce the entrainment of motile fish through the system, although the caps are commonly thought of as impingement-reduction technologies because they target larger organisms. Velocity caps have been shown to reduce impingement rates when compared with a shoreline intake structure.

Likewise, the location of the intake structure in a deep, offshore setting may contribute to lower rates of entrainment when compared with a shoreline intake if the near-shore environment is more biologically productive. Furthermore, each CWIS is angled to the incoming flow and incorporates other measures (vertical louvers) to prevent the impingement of organisms against the screens. Organisms that are diverted are returned to the source water through a combination fish elevator/return pipeline. This study did not evaluate the effectiveness of any of these measures.

The current orders for Unit 2 and Unit 3 do not contain numeric or narrative limitations regarding impingement or entrainment resulting from CWIS operation, but do require quarterly monitoring of impingement at each intake structure (coinciding with scheduled heat treatments). Because the current orders were adopted following implementation of the Phase II rule but prior to the Second Circuit Court's decision and EPA's notice of suspension, each contains a requirement to adhere to the rule's compliance schedule.

These requirements consist of various data collection provisions and studies that were to be submitted in support of an eventual best technology available (BTA) determination made by the SDRWQCB. Based on the record available for review, SONGS has been compliant with this permit requirement. No information from the SDRWQCB is available indicating how it intends to proceed with the permit requirements in light of the changes to the Phase II rule.

SONGS maintains a coastal development permit issued by the California Coastal Commission (CCC). In 1991, the CCC adopted permit conditions requiring SONGS to develop and fund various mitigation measures that address adverse impacts caused by the facility's operation, including the intake structures. These conditions include the installation and operation of fish barrier devices at the intakes as well as restoration measures to enhance the affected areas. This study did not evaluate compliance with CCC permit requirements (CCC 2005).

3.0 WET COOLING SYSTEM RETROFIT

3.1 OVERVIEW

This study evaluates the use of saltwater wet cooling towers at SONGS, with the current source water (Pacific Ocean) continuing to provide makeup water to the facility. Conversion of the existing once-through cooling system to wet cooling towers will reduce the facility's current intake capacity by approximately 95 percent; rates of impingement and entrainment will decline by a similar proportion. Use of reclaimed water was considered for SONGS but not analyzed in detail because the available volume cannot serve as a replacement for once-through cooling water.

As a makeup water source, reclaimed water may be an attractive alternative when considering additional benefits its use may provide, such as avoidance of conflicts with effluent limitations or air emission standards. Securing a sufficient volume of makeup water from secondary or reclaimed sources in the vicinity (45 to 50 mgd in a freshwater configuration) is difficult and would require connections to multiple facilities. Use of reclaimed water is discussed further in Section 3.4.4.

The configuration of the wet cooling towers—their size and location—was based on best professional judgment (BPJ) using the criteria outlined in Chapter 5 and designed to meet the performance benchmarks in the most cost-effective manner. Plume-abated towers were selected based on the proximity to major infrastructure (San Diego Freeway) and potential public safety concerns.

A previous analysis of a wet cooling tower installation at SONGS, developed by PLG, Inc., for SCE in 1990, was also considered in determining the placement and general limitations of the final configuration selected for the site. Information not available to this study that offers a more complete characterization of the facility may lead to different conclusions regarding the physical configuration of the towers.

Based on a review of information provided by SCE and obtained from public records, installation of wet cooling towers at SONGS is difficult and may conflict with protected uses of adjoining state lands, but remains a logistically feasible option. This study assumes such conflicts can be overcome. Conversion to a wet cooling tower system will reduce the facility's available output by an annual average of 4.45 percent (approximately 100 MW). This is likely to be a major consideration if such a project moves forward. The final design of the plume-abated cooling towers, described below, represents the most practical installation that could be developed for the facility.

This study developed a conceptual design of wet cooling towers sufficient to meet the cooling demand for the steam turbine portion of the combined-cycle unit at SONGS at its rated output during peak climate conditions. Cost estimates are based on vendor quotes developed using the available information and the various design constraints identified at SONGS.

The overall practicality of retrofitting the combined-cycle unit at SONGS will require an evaluation of factors outside the scope of this study, such as the projected life span of the generating units and their role in the overall reliability of electricity production and transmission in California, particularly the San Diego region.

3.2 DESIGN BASIS

3.2.1 CONDENSER SPECIFICATIONS

For this study, the conceptual design of the cooling towers selected for SONGS is based on the assumption that the condenser flow rate and thermal load will remain unchanged from the current system. Although no provision is included to re-optimize the condenser performance for service with a cooling tower, some modifications to the condenser (tube sheet and water box reinforcement) may be necessary to handle the increased water pressures that will result from the increased total pump head required to raise water to the elevation of the cooling tower riser.[1] The practicality and difficulty of these modifications depend on the configuration of each unit, but are assumed to be feasible at SONGS. Additional costs associated with condenser modifications are included in the discussion of capital expenditures (Section 3.4).

If wet cooling towers were installed, SONGS, as a facility with a projected remaining life span of 15 years or more (currently licensed to operate through 2022), would likely pursue an overall strategy that included re-optimizing the condenser to minimize performance losses resulting from a conversion. Re-optimization would require extensive demolition and excavation of the existing site to gain access to the existing condensers (23 feet below grade level) and reconfigure the tubes and supply and return lines connecting to the water boxes.

Because of the complexity and level of detail required to develop an accurate estimate of a condenser re-optimization for SONGS, no attempt is made to characterize the cost or impact on facility downtime during construction in this study. A previous analysis conducted for the Diablo Canyon Power Plant notes significant increases in cost and shutdown loss to accomplish the necessary modifications (BES 2003).

Information provided by SONGS was largely used as the basis for the cooling tower design. In some cases, the data were incomplete or conflicted with values obtained from other sources. Where possible, questionable values were verified or corrected using other known information about the condenser. The condenser specification data sheets provided by SCE did not contain information detailing the total surface area or heat transfer coefficients for the condenser tubes.

In lieu of this information, a replacement value was calculated based on other known characteristics about the system (e.g., design inlet temperature, condenser rise, thermal load, tube material, etc.) using Heat Exchange Institute guidelines (HEI 2007). The resulting calculation is referred to as the “U-A” value and is substituted into the relevant equations as necessary.

Table N–5 summarizes the condenser design specifications for Unit 2 and Unit 3 used in this study.

[1] In this context, re-optimization refers to a comprehensive overhaul of the condenser, such as re-tubing or converting the flow from single to multiple passes. Modifications are generally limited to reinforcement measures to enable the condenser to withstand the increased pressures.

Table N–5. Condenser Design Specifications

	Unit 2	Unit 3
Thermal load (MMBTU/hr)	7950	7950
Surface area (ft^2)	*NA*	*NA*
Condenser flow rate (gpm)	795,600	795,600
Tube material	Titanium 338-73	Titanium 338-73
Heat transfer coefficient (U_d)	NA	NA
"U-A" value (BTU/hr·°F)	~560,800,000	~560,800,000
Cleanliness factor	0.9	0.9
Inlet temperature (°F)	64	64
Temperature rise (°F)	19	19
Steam condensate temperature (°F)	102.7	102.7
Turbine exhaust pressure (in. HgA)	2.1	2.1

3.2.2 AMBIENT ENVIRONMENTAL CONDITIONS

SONGS is in San Diego County, approximately 2.5 miles south of the city of San Clemente. Cooling water is withdrawn through two submerged offshore intakes extending 3,183 feet into the Pacific Ocean. Condenser inlet temperature data were provided by SCE for January through November of 2006. Additional information to supplement this data set was obtained from the National Oceanographic and Atmospheric Administration (NOAA) *Coastal Water Temperature Guide—Dana Point, CA* (NOAA 2007).

The wet bulb temperature used in the development of the overall cooling tower design was obtained from American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) publications. Data for San Clemente, California, indicate a 1 percent ambient wet bulb temperature of 70° F (ASHRAE 2006). An approach temperature of 12° F was selected based on the site configuration and vendor input. At the design wet bulb and approach temperatures, the cooling towers will yield "cold" water at a temperature of 82° F. Monthly maximum wet bulb temperatures used in the development of energy penalty estimates in Section 4.6 were obtained from National Climatic Data Center (NCDC) climate normals for Oceanside, California (NCDC 2006). Climate data used in this analysis are summarized in Table N–6.

Table N-6. Surface Water and Ambient Wet Bulb Temperatures

	Surface (°F)	Ambient wet bulb (°F)
January	59.8	52.2
February	59.9	53.5
March	61.6	56.4
April	61.3	58.2
May	64.8	63.3
June	68.1	66.4
July	68.6	69.3
August	67.4	70.0
September	67.6	64.8
October	65.6	59.6
November	64.3	53.0
December	60.8	51.8

3.2.3 LOCAL USE RESTRICTIONS

3.2.3.1 NOISE

Development in the vicinity of SONGS is regulated by the County of San Diego General Plan and the Local Coastal Plan (LCP) as well as by Camp Pendleton's guidelines or restrictions. Due to the proximity of the city of San Clemente, that city's general plan is also considered when modifications to SONGS are proposed that have the potential to affect the city. The San Diego General Plan and LCP outline narrative noise criteria to be used as a guide for future development, but do not identify numeric noise limits for new construction.

Based on consultation with the County of San Diego Department of Planning and Land Use, any measures limiting noise from a wet cooling tower at SONGS would be considered based on the project's final design criteria with respect to the relevant ordinances and development codes of San Diego County, the city of San Clemente, and Camp Pendleton. In general, noise would likely not be permitted to exceed 70 dBA at the nearest area of impact. Given the undeveloped nature of the surrounding area and the proximity to noise from the San Diego Freeway, stringent limitations on noise from wet cooling towers are unlikely. Accordingly, the overall design of the wet cooling tower installation for SONGS does not require any measures to specifically address noise, such as low-noise fans or barrier walls.

The proximity to public recreational areas (San Onofre State Beach) and protected areas may warrant measures to mitigate lower-level noise impacts, but these cannot be determined within the framework of this study.

3.2.3.2 BUILDING HEIGHT

According to the San Diego County General Plan, SONGS is within a land use zone designated as public or semipublic. Consultation with the County of San Diego Department of Planning and Land Use indicates building height restrictions would be evaluated on a conditional use basis with input from relevant agencies with oversight of the area (CCC, Camp Pendleton). Given the existing height of the current structures at SONGS, this study selected a height restriction of 75 feet above grade level for any new structures. The height of the wet cooling towers designed for SONGS, from grade level to the top of the fan deck, is 62 feet.

3.2.3.3 PLUME ABATEMENT

Local zoning ordinances do not contain any specific criteria for addressing impacts associated with a wet cooling tower plume. The proximity of SONGS to the San Diego Freeway, however, may necessitate incorporating plume abatement measures. As shown in Figure N–1, the San Diego Freeway parallels the eastern boundary of the beachfront complex for approximately 1.25 miles at a distance of fewer than 250 feet in some locations. Placement of a conventional (not plume-abated) wet cooling tower, combined with the direction of prevailing winds at the site (generally from the west), would likely create a public safety hazard on the heavily traveled freeway.

Furthermore, the proximity of SONGS to coastal recreational and protected areas, and the potential visual impact on these resources, may require plume abatement measures. California Energy Commission (CEC) siting guidelines and Coastal Act provisions evaluate the total size and persistence of a visual plume with respect to aesthetic standards for coastal resources; significant visual changes resulting from a persistent plume would likely be subject to additional controls.

For the above reasons, the cooling tower design evaluated for installation at SONGS includes plume abatement technologies for all cells.

3.2.3.4 DRIFT AND PARTICULATE EMISSIONS

Drift elimination measures that are considered best available control technology (BACT) are required for all cooling towers evaluated in this study, regardless of their location. State-of-the-art drift eliminators are included for each cooling tower cell at SONGS, with an accepted efficiency of 0.0005 percent. Because cooling tower PM_{10} emissions are a function of the rate of drift, drift eliminators are also considered BACT for PM_{10} emissions from wet cooling towers.

This efficiency can be verified by a proper in situ test, which accounts for site-specific climate, water, and operating conditions. Testing based on the Isokinetic Drift Test Code, published by the Cooling Tower Institute, is only required at initial start-up on one representative cell of each of the 12 towers, for an approximate cost of $720,000 (CTI 1994). This cost is not itemized in the final analysis and is instead included as part of the indirect cost estimate (Section 4.3).

3.2.3.5 FACILITY CONFIGURATION AND AREA CONSTRAINTS

The limited space available at the beachfront section of SONGS creates significant challenges for identifying sufficient area to accommodate the large cooling towers that will be necessary to serve Unit 2 and Unit 3. Much of this area is currently occupied by the power blocks for Unit 2 and Unit 3, the decommissioned site for Unit 1, the dry cask storage area (for spent fuel rods), the switchyard, and various support structures, parking areas, and maintenance buildings. Placement of wet cooling towers at SONGS will require removal and/or relocation of some of these structures as well as procurement of areas outside the current SCE property line.

The Mesa Complex, across the San Diego Freeway, was eliminated from consideration due to the hilly terrain that would require grading and excavation to prepare the site for cooling towers. Placement on the Mesa Complex side would require excavating tunnels under the freeway sufficiently sized to accommodate four 12-foot-diameter pipes. Even if these limitations could be overcome, the increased cost is likely to be significant, compared with an installation on the facility's beachfront side.

The north end of the SONGS property, as shown in Figure N–3, has few relatively close areas that can support a wet cooling tower complex. Area 1 comprises 510,000 square feet (1,700 feet by 300 feet) on a bluff overlooking San Onofre State Beach and is largely occupied by an employee parking lot.

Area 2 is the site of the retired Unit 1 complex and ongoing decommissioning activities occupying a 250,000-square-foot area immediately adjacent to Unit 2. This area could be used in conjunction with other areas to accommodate a portion of the cooling tower cells necessary for Unit 2 and to minimize some of the pipeline distances. However, it was eliminated from further consideration because it is not known when decommissioning activities will be completed and whether the area would be available for use at that time. Other areas were initially considered but ultimately eliminated because they currently house the spent fuel rod dry cask storage system and administration buildings (Area 3) and the facility switchyard (Area 4).

Area 1 was selected as the most practical location to accommodate the cooling towers for Unit 2. This study did not evaluate in detail the consequences of relocating the employee parking area, most likely to a location at the Mesa Complex, nor did it include the potential costs of that relocation.

The south end of the SONGS property, as shown in Figure N–4, is similarly constrained in terms of available siting locations. The combination of Area 5, occupied by the demineralizing system and employee parking, and Area 6, occupied by unidentified maintenance/support buildings, would be large enough to accommodate the cooling towers for Unit 3. These areas were eliminated from consideration, however, because their use would require removing several essential systems to other areas of the site. The disruption this would cause and the limited areas available for relocation are potentially significant issues that cannot be quantified within the scope of this study.

Area 7 is not within the boundaries of the current SCE property. It is an undeveloped coastal bluff overlooking the beach and comprises approximately 800,000 square feet (2,000 feet by 400 feet) of state park land. Use of the bluff for wet cooling towers is problematic due to the presence of Southern Coastal Bluff Scrub, which has been identified by the California Department of Fish and Game as a rare habitat type.

Thus, under the Coastal Act, this area is considered an Environmentally Sensitive Habitat (ESHA) and is subject to limits on development that encroaches upon it. The CCC has noted that the coastal development permit (CDP) issued to SCE for SONGS does not allow for significant clearing of vegetation and would require, at a minimum, an amendment to allow constructing wet cooling towers in this area.

PLG, Inc., in an analysis developed for SCE in 1990, first proposed this area as the Unit 3 cooling towers site but did not address the potential conflicts its use would entail (PLG 1990). This study (as does the PLG report) develops a wet cooling tower configuration for Unit 3 that also assumes the availability of the coastal bluff area identified as Area 7, with the strong caveat that use of this area would have to overcome substantial hurdles to comply with Coastal Act provisions. Area 7 is considered in this study only because no other areas were identified that could conceivably accommodate the towers for Unit 3. In the event Area 7 is unavailable, it is unlikely that a reasonable cooling tower configuration could be developed without significant disruption to facility operations.

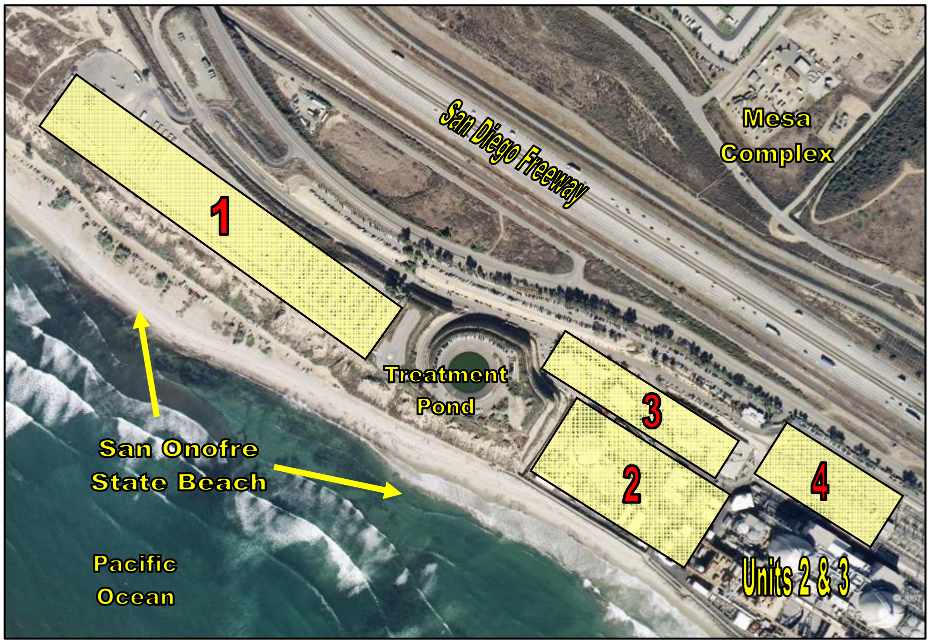

Figure N-3. SONGS Site View (North End)

Figure N–4. SONGS Site View (South End)

3.3 CONCEPTUAL DESIGN

Based on the design constraints discussed above, two wet cooling tower complexes, each consisting of six towers, were selected to replace the current once-through cooling system at SONGS, for a total of 12 towers. Each tower complex will operate independently and be dedicated to one unit. Each tower at SONGS consists of plume-abated cells arranged in a multicell, inline configuration.

3.3.1 SIZE

Each tower is constructed over a concrete collection basin 4 feet deep. The basin is larger than the footprint of the tower structure, extending an additional 2 feet in each direction. The concrete used for construction is suitable for saltwater applications. The principal tower material is fiberglass reinforced plastic (FRP) with stainless steel fittings. These materials are more resistant to the higher corrosive effects of saltwater. The dry coil sections that form the plume abatement portion of the towers are constructed of titanium rather than stainless steel to limit performance losses that might result from corrosion.

The size of the tower is primarily based on the thermal load rejected to the tower by the surface condenser and a 12° F approach to the ambient wet bulb temperature. Flow rates through the condenser, as well as the design cooling range and terminal temperature difference, remain unchanged.

General characteristics of the wet cooling tower selected for SONGS are summarized in Table N–7.

Table N–7. Wet Cooling Tower Design

	Tower Complex 1 (Unit 2)	Tower Complex 2 (Unit 3)
Thermal load (MMBTU/hr)	7950	7950
Circulating flow (gpm)	795,600	795,600
Number of cells	48	48
Plume-free design point	50°F dry bulb 90% relative humidity	50°F dry bulb 90% relative humidity
Tower type	Mechanical draft	Mechanical draft
Flow orientation	Counterflow	Counterflow
Fill type	Modular splash	Modular splash
Arrangement	Inline	Inline
Primary tower material	FRP	FRP
Tower dimensions (l x w x h) (ft) [a]	480 x 66 x 62	480 x 66 x 62
Tower footprint with basin (l x w) (ft) [a]	484 x 70	484 x 70

[a] Six individual towers of these dimensions form each cooling tower complex.

3.3.2 LOCATION

The initial site selection for each tower was based on the desire to locate each tower as close as possible to its respective generating unit to minimize the supply and return pipe distances and any increases in total pump head and brake horsepower. The available options at SONGS do not allow for close placement. Figure N–5 identifies the approximate location of Tower Complex 1 (Unit 2) and supply and return piping. Figure N–6 identifies the approximate location of Tower Complex 2 (Unit 3) and supply and return piping.

Figure N–5. Location of Tower Complex 1

Figure N-6. Location of Tower Complex 2

3.3.3 PIPING

The routing of the main supply and return pipelines to and from the condensers is based on the 1990 PLG report, which assumed placement of long sections at the foot of the bluff overlooking the beach. All supply and return pipes are made of prestressed concrete cylinder pipe (PCCP) suitable for saltwater applications. Pipes extending from the towers to the edge of the bluff will be located underground. These pipes range in size from 120 to 140 inches in diameter.

Pipes extending from the bluff to the condenser are also PCCP, but placed above ground. The location of the condensers at SONGS (23 feet below grade level) makes a direct connection to the supply and return lines difficult. This study assumes supply and return lines would be connected to the existing intake and discharge pipes at some point beyond the seawall that serves as the western boundary of the main facility.

All riser piping (extending from the foot of the tower to the level of water distribution) is constructed of FRP.

Appendix B details the total quantity of each pipe size and type for SONGS.

3.3.4 FANS AND PUMPS

Each tower cell uses an independent single-speed fan. The fan size and motor power are the same for each cell in all 12 towers.

This analysis includes new pumps to circulate water between the condensers and cooling tower. Pumps are sized according to the flow rate for the tower, the relative distance between the tower and condenser, and the total head required to deliver water to the top of the cooling tower riser. A separate, multilevel pump house is constructed for each cooling tower complex and is sized to accommodate the motor control centers (MCCs) and appropriate electrical switchgear. The electrical installation includes all necessary transformers, cabling, cable trays, lighting, and lightning protection. A 50-ton overhead crane is also included to allow for pump servicing.

Fan and pump characteristics associated with a wet cooling tower at SONGS are summarized in Table N–8. The net electrical demand of the fans and new pumps are discussed further as part of the energy penalty analysis in Section 4.6.

Table N–8. Cooling Tower Fans and Pumps

		Tower Complex 1 (Unit 2)	Tower Complex 1 (Unit 3)
Fans	Number	48	48
	Type	Single speed	Single speed
	Efficiency	0.95	0.95
	Motor power (hp)	259	259
Pumps	Number	5	5
	Type	50% recirculating Mixed flow Suspended bowl Vertical	50% recirculating Mixed flow Suspended bowl Vertical
	Efficiency	0.88	0.88
	Motor power (hp)	7,000	7,000

3.4 ENVIRONMENTAL EFFECTS

Converting the existing once-through cooling system at SONGS to wet cooling towers will significantly reduce the intake of seawater from the Pacific Ocean and will presumably reduce impingement and entrainment by a similar proportion. Because closed-cycle systems will almost always result in condenser cooling water temperatures higher than those found in a comparable once-through system, wet towers will increase the operating heat rates at Unit 2 and Unit 3, thereby decreasing the facility's overall efficiency. Additional power will also be consumed by the tower fans and circulating pumps.

As a PWR facility, SONGS is generally limited in how it can respond to these changes. While fossil fuel facilities may be able to increase the amount of fuel consumed to compensate for any shortfall, the complexities of a nuclear-fueled steam-generating unit and the inherent safety precautions that govern its operation generally preclude SONGS from increasing the thermal input to the system. Thus, any compensation for the reduced output must be obtained from other facilities on the grid.

Depending on the fuel source and efficiency of the facility providing the additional electricity, emissions for pollutants such as PM10, SOx, and NOx may increase and may require additional control measures or the purchase of emission credits to meet air quality regulations. The towers themselves will constitute a new source of PM10 emissions; the annual mass increase will largely depend on the utilization capacity of the generating units the tower serves.

If SONGS retains its NPDES permit to discharge wastewater to the Pacific Ocean with a wet cooling tower system, it may have to address revised effluent limitations resulting from the substantial change in the quantity and characteristics of the discharge. Impacts from the discharge of elevated-temperature wastes associated with the current once-through system, if any, will be minimized by using a wet cooling system.

3.4.1 AIR EMISSIONS

Drift volumes from wet cooling towers are expected to be within the range of 0.5 gallons for every 100,000 gallons of circulating water in the towers. At SONGS, this corresponds to a rate of approximately 8.2 gpm based on the maximum combined flow in the two tower complexes. The relative distances of the wet cooling towers from most facility structures (Figure N–5 and Figure N–6) do not appear to create any immediate concern over the effects of salt deposition on the switchyard or other sensitive equipment. Depending on the relocation of parking areas and other structures, drift is likely to be considered more of a nuisance rather than a threat to public health or safety, and will manifest itself as a whitish coating on exposed surfaces.

Total PM_{10} emissions from the SONGS cooling towers are a function of the number of hours in operation, overall water quality in the tower, and the evaporation rate of drift droplets prior to deposition on the ground. Makeup water at SONGS will be obtained from the same source currently used for once-through cooling water (Pacific Ocean). At 1.5 cycles of concentration and assuming an initial Total Dissolved Solids (TDS) value of 35 parts per thousand (ppt), the water within the cooling towers will reach a maximum TDS level of roughly 53 ppt. Any drift droplets exiting the tower will have the same TDS concentration.

As a nuclear facility, SONGS does not emit significant quantities of PM_{10}, SO_x, CO_2, or NO_x from its current operations. The emission of PM_{10} in substantial quantity from the wet cooling towers is likely to trigger enforcement of air quality regulations and may require SCE to obtain necessary operating permits from the San Diego County Air Pollution Control District (APCD). Table N–9 summarizes the estimated drift and PM_{10} emissions from the SONGS wet cooling towers.

Table N–9. Full Load Drift and Particulate Estimates

	PM_{10} (lbs/hr)	PM_{10} (tons/year)	Drift (gpm)	Drift (lbs/hr)
Tower Complex 1	105	458	4.1	1,991
Tower Complex 2	105	458	4.1	1,991
Total SONGS PM_{10} and drift emissions	**210**	**916**	**8.2**	**3,982**

3.4.2 MAKEUP WATER

The volume of makeup water required by the cooling tower at SONGS is the sum of evaporative loss and the blowdown volume required to maintain the circulating water in the tower at the design TDS concentration. Drift expelled from the tower represents an insignificant volume by comparison and is accounted for by rounding up estimates of evaporative losses. Makeup water volumes are based on design conditions, and may fluctuate seasonally depending on climate conditions and facility operations. Use of wet cooling towers will reduce once-through cooling water withdrawals from the Pacific Ocean by approximately 95 percent over the current design intake capacity. (See Table N–10.)

Table N–10. Makeup Water Demand

	Tower circulating flow (gpm)	Evaporation (gpm)	Blowdown (gpm)	Total makeup water (gpm)
Tower Complex 1	795,600	12,800	25,600	38,400
Tower Complex 2	795,600	12,800	25,600	38,400
Total SONGS makeup water demand	**1,591,200**	**25,600**	**51,200**	**76,800**

The existing circulating water pumps are rated at 207,000 gpm while makeup water demand is only 38,400 per unit. In this case, the difference between these two values makes it unlikely that the existing pumps can be repurposed for use with the new system. The design developed for DCPP includes four new circulating water new circulating water pumps (two per unit) rated at 30,000 gpm each.

The existing once-through cooling system at SONGS does not treat water withdrawn from the Pacific Ocean, with the exception of screening for debris and larger organisms and periodic chlorination to control biofouling in the condenser tubes. Biofouling is controlled by periodic heat treatments that raise the temperature of the circulating water to 100º F.

Makeup water will continue to be withdrawn from the Pacific Ocean.

The wet cooling tower system proposed for SONGS includes water treatment for standard operational measures, i.e., fouling and corrosion control. Chemical treatment allowances are included in annual O&M costs. It is assumed that the current once-through cooling water quality will be acceptable for use in a seawater cooling tower (with continued screening and chlorination) and will not require any pretreatment to enable its use.

3.4.3 NPDES PERMIT COMPLIANCE

At maximum operation, wet cooling towers at SONGS will discharge approximately 73 mgd of blowdown in addition to other in-plant waste streams, such as regeneration wastes, boiler blowdown, and treated sanitary wastes. These low-volume wastes may add an additional 20 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, SONGS will be required to modify its existing individual wastewater discharge (NPDES) permit.

Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES permits CA0108073 (Unit 2) and CA0108181 (Unit 3), as implemented by SDRWQCB orders R9-2005-0005 (Unit 2) and R9-2005-0006 (Unit 3). All wastewaters are discharged to the Pacific Ocean through discharge conduits extending 8,350 feet and 5,900 feet offshore, terminating at a depth of 49 feet. The existing order contains effluent limitations based on the 2001 California Ocean Plan.

SONGS will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities (40 CFR 423.13(d)(1)). These ELGs set numeric limitations for chromium and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity). Because ELGs are technology-based limitations, mixing zones or dilution factors are not applicable when determining compliance; limits must be met at the point of discharge from the cooling tower prior to commingling with any other waste stream. ELGs for cooling tower blowdown target priority pollutants that are contributed by maintenance chemicals and do not apply when limits may be exceeded as a result of background concentrations or other sources. Further discussion can be found in Chapter 4, Section 3.6.

Conversion to wet cooling towers will alter the volume and composition of a facility's wastewater discharge because wet towers concentrate certain pollutants in the effluent waste stream. The cooling towers designed for SONGS operate at 1.5 cycles of concentration, i.e., the blowdown discharge will contain a dissolved solids concentration 50 percent higher than the makeup water.

Changes to discharge composition may affect compliance with water quality objectives included in the Ocean Plan. If compliance with these objectives becomes problematic, alternative treatment or discharge methods may be necessary. Compliance may be achieved by altering the discharge configuration in such a way as to increase dilution (e.g., diffuser ports), or by seeking a mixing zone and dilution credits as permissible under the Ocean Plan. Alternately, some low volume waste streams (e.g., boiler blowdown, laboratory drains) may be diverted, with necessary permits, for treatment at a POTW.

If more pollutant-specific treatment methods, such as filtration or precipitation technologies, become necessary to meet WQBELs, the initial capital cost may range from $2 to $5.50 per 1,000 gallons of treatment capacity, with annual costs of approximately $0.5 per gallon of capacity, depending on the method of treatment (FRTR 2002). Hazardous material disposal fees and permits would further increase costs.

This evaluation did not include alternative discharge or effluent treatment measures in the conceptual design because the variables used to determine final WQBELs, which would be used to determine the type and scope of the desired compliance method, cannot be quantified here. Likewise, the final cost evaluation (Section 4.0) does not include any allowance for these possibilities.

Thermal discharge standards are based on narrative criteria established for discharges to coastal waters under the Thermal Plan, which requires that existing discharges of elevated-temperature wastes comply with effluent limitations necessary to assure the protection of designated beneficial uses. The SDRWQCB has implemented this provision by establishing a maximum discharge temperature of no more than 25º F in excess of the temperature of the receiving water during normal operations (SDRWQCB 2005a, 2005b).

Information available for review indicates SONGS has consistently been able to comply with this requirement. Because cooling tower blowdown will be taken from the "cold" side of the tower, conversion to a wet cooling system will significantly reduce the discharge temperature (to less than 82º F) and the size of any related thermal plume in the receiving water.

3.4.4 RECLAIMED WATER

The use of reclaimed or alternative water sources could potentially eliminate all surface water withdrawals at SONGS. Doing so would completely eliminate impingement and entrainment concerns, and might enable the facility to avoid possible effluent quality and permit compliance issues, depending on the quality of reclaimed water available for use. In addition, wet cooling towers using reclaimed water would be expected to have lower PM_{10} emissions due to the lower TDS levels.

The California State Water Resources Control Board (SWRCB), in 1975, issued a policy statement requiring the consideration of alternative cooling methods in new power plants, including the use of reclaimed water, over the use of freshwater (SWRCB 1975). There is no similar policy regarding the use of marine waters, but the clear preference of state agencies is to encourage alternative cooling methods, including the use of reclaimed water, wherever possible.

The present volume of available reclaimed water within a 15-mile radius of SONGS (46 mgd) does not meet the current once-through cooling demand; thus, the use of reclaimed water is only applicable as a source of makeup water for a wet cooling tower system. This study did not pursue a detailed investigation of the use of reclaimed water because the conversion of the SONGS once-through cooling systems to saltwater cooling towers enables the facility to meet the performance targets for impingement and entrainment impact reductions outlined in the 2006 California Ocean Protection Council (OPC) Resolution on Once-Through Cooling Water (see Chapter 1).

To be acceptable for use as makeup water in cooling towers, reclaimed water must meet tertiary treatment and disinfection standards under California Code of Regulations (CCR) Title 22. If the reclaimed water is not treated to the required levels, SONGS would be required to provide sufficient treatment prior to use in the cooling towers.

Two combined outfalls to the Pacific Ocean were identified within a 15-mile radius of SONGS. These outfalls are managed by municipal agencies or authorities and combine the treated effluent from several publicly owned treatment works (POTWs) in the region. The combined discharge from these outfalls is 46 mgd. Figure N–8 shows the relative locations of these facilities to SONGS.

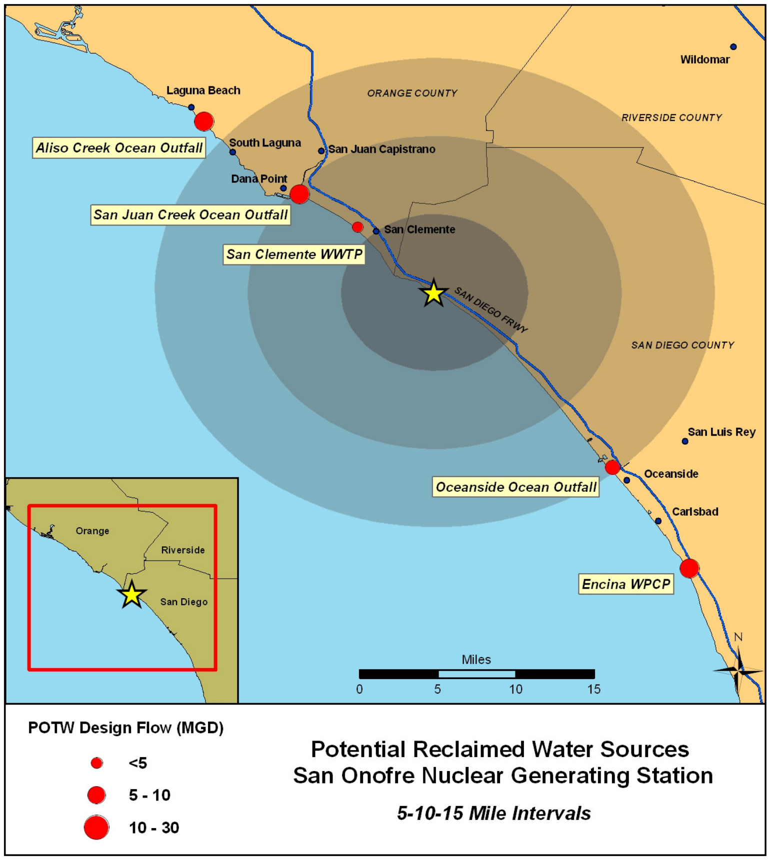

Figure N–7. Reclaimed Water Sources

- *Oceanside Ocean Outfall—City of Oceanside*
  Discharge volume: 27 mgd
  Distance: 15 miles SE
  Treatment level: Secondary

  The Oceanside Ocean Outfall (OOO) discharges treated effluent received from the San Luis Rey Wastewater Treatment Plant and La Salina Wastewater Treatment Plant operated by the city of Oceanside, the Fallbrook Public Utility District, and the U.S. Marine Corps Base at Camp Pendleton. The OOO extends approximately 8,000 feet offshore into the Pacific Ocean, terminating at a depth of 103 feet. No information is available regarding the volume of water currently reclaimed for other uses.

- *San Juan Creek Ocean Outfall—South Orange County Water Authority (SOCWA)*
  Discharge volume: 19 mgd
  Distance: 9.5 miles NW
  Treatment level: Secondary

  The San Juan Creek Ocean Outfall (SJCOO) discharges treated effluent received from the city of San Juan Capistrano, in addition to the South Coast, Santa Margarita, Trabuco Canyon, and Moulton Niguel water districts. The SJCOO extends approximately 10,500 feet offshore, southwest of Doheny State Beach. A portion of the wastewater generated in the SOCWA region is reclaimed for other purposes at the South Coast Water District's Advanced Water Treatment Plant. The volume of water discharged through the SJCOO represents the available volume of water that could be used to supply a portion of the makeup water demand at SONGS (45 to 50 mgd as freshwater towers).

- *San Clemente Wastewater Treatment Plant—San Clemente*
  Discharge volume: 4.7 mgd
  Distance: 6 miles NW
  Treatment level: Tertiary

  A portion of the tertiary treated water is used for local irrigation projects. No additional information available.

The costs associated with installing transmission pipelines (excavation/drilling, material, labor), in addition to design and permitting costs, are difficult to quantify in the absence of a detailed analysis of various site-specific parameters that influence the final configuration. Based on data compiled for this study and others, the estimated installed cost of a 60-inch prestressed concrete cylinder pipe, sufficient to provide 50 mgd to SONGS, is $600 per linear foot, or approximately $3.2 million per mile. Additional considerations, such as pump capacity and any required treatment, would increase the total cost. This estimate is based on excavating and installing a pipeline on land. It may be feasible or more practical to establish a connection to the outfalls by pipelines installed in the ocean.

Regulatory concerns beyond the scope of this investigation, however, may make the use of reclaimed water comparable or preferable to the use of saltwater from marine sources as makeup water. Reclaimed water may enable SONGS to reduce PM_{10} emissions from the cooling tower, which is a concern, given the current nonattainment status of the San Diego air basin, or to eliminate potential conflicts with water discharge limitations. SONGS might also realize other benefits by using reclaimed water in the form of reduced O&M costs. At any facility where wet cooling towers are a feasible alternative, reclaimed water may be used as a makeup water source. The practicality of its use, however, depends on the overall cost, availability, and additional environmental benefits that may occur.

3.4.5 THERMAL EFFICIENCY

The use of wet cooling towers at SONGS will increase the temperature of the condenser inlet water by 6 to 13° F above the surface water temperature, depending on the ambient wet bulb temperature at the time. The generating units at SONGS are designed to operate at the conditions described in Table N–11. The resulting monthly difference between once-through and wet cooling tower condenser inlet temperatures at SONGS is described in Figure N–8.

Table N–11. Design Thermal Conditions

	Unit 2	Unit 3
Design backpressure (in. HgA)	2.1	2.1
Design water temperature (°F)	64	64
Turbine inlet temp (°F)	521	521
Turbine inlet pressure (psia)	821	821
Full load heat rate (BTU/kWh)	9,940	9,940

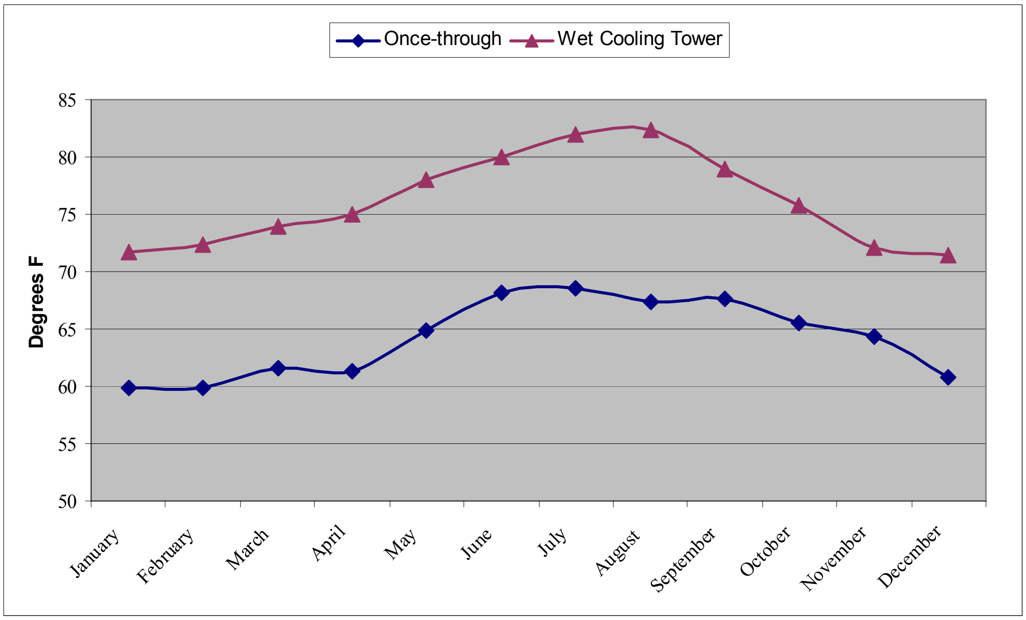

Figure N–8. Condenser Inlet Temperatures

Backpressures for the once-through and wet cooling tower configurations were calculated using the design criteria described in the sections above on a monthly basis using ambient climate data (Table N–6). In general, backpressures associated with the wet cooling tower were elevated by 0.5 to 0.85 inches HgA compared with the current once-through system (Figure N–9 and Figure N–11).

Heat rate adjustments were calculated by comparing the theoretical change in available energy that occurs at different turbine exhaust backpressures, assuming the thermal load and turbine inlet pressure remain constant, i.e., at the maximum load rating.4 The relative change at different backpressures was compared with the value calculated for the design conditions (i.e., at design turbine inlet and exhaust backpressures) and plotted as a percentage of the maximum operating heat rate to develop estimated correction curves (Figure N–10 and Figure N–12). A comparison was then made between the relative heat rates of the once-through and wet cooling systems for a given month. The difference between these two values represents the net increase in heat rate that would be expected in a converted system.

Table N–12 summarizes the annual average heat rate increase for each unit as well as the increase associated with the peak demand period of July-August-September. Monthly values were used to develop an estimate of the monetized value of these heat rate changes (Section 4.6). Month-by-month calculations are presented in Appendix A.

Table N–12. Summary of Estimated Heat Rate Increases

	Unit 2	Unit 3
Peak (July-August-September)	3.74%	3.74%
Annual average	2.88%	2.88%

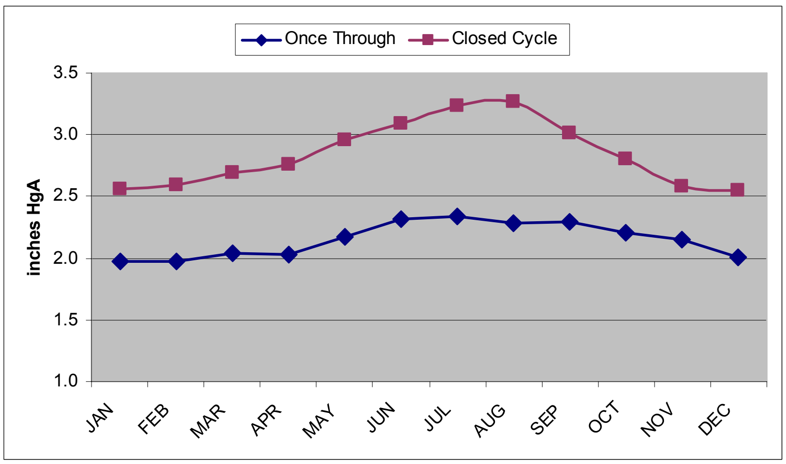

Figure N–9. Estimated Backpressures (Unit 2)

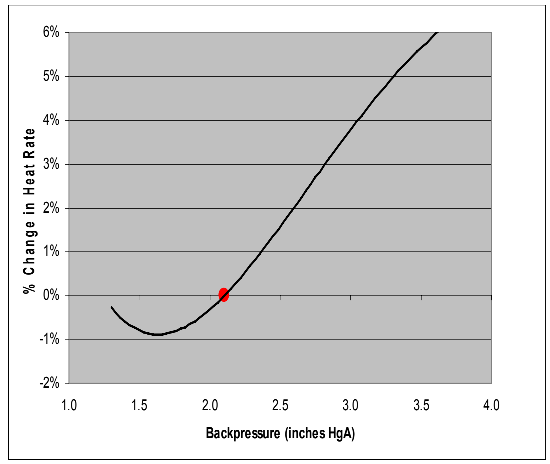

Figure N–10. Estimated Heat Rate Correction (Unit 2)

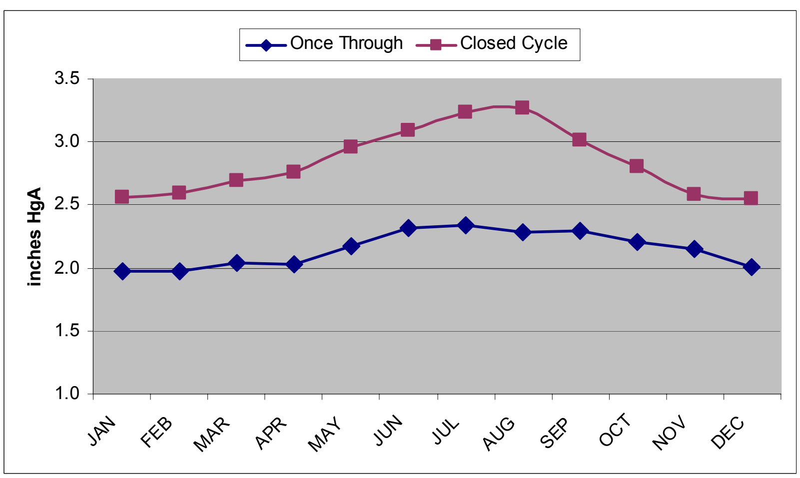

Figure N–11. Estimated Backpressures (Unit 3)

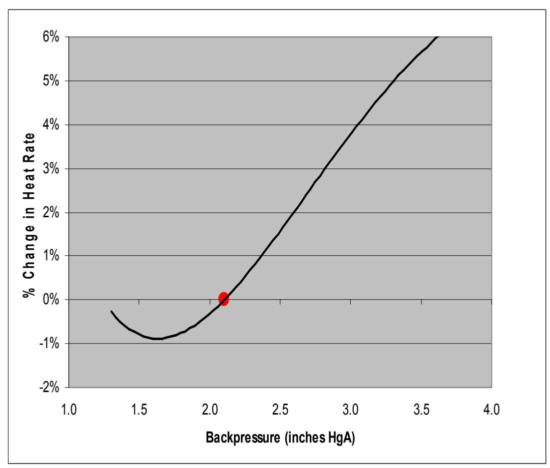

Figure N–12. Estimated Heat Rate Correction (Unit 3)

4.0 RETROFIT COST ANALYSIS

The wet cooling system retrofit estimate for SONGS is based on incorporating plume-abated wet cooling towers as a replacement for the existing once-through systems for each unit. Standard cost elements for this project include the following:

- Direct (cooling tower installation, civil/structural, mechanical, piping, electrical, and demolition)
- Indirect (smaller project costs not itemized)
- Contingency (allowance for unknown project variables)
- Operations and maintenance (non–energy related cooling tower operations)
- Energy penalty (includes increased parasitic use from fans and pumps as well as decreased thermal efficiency)
- Revenue loss from shutdown (net loss in revenue during construction phase)

The cost analysis does not include allowances for elements that are not quantified in this study, such as land acquisition, effluent treatment, or air emission reduction credits. The methodology used to develop cost estimates is discussed in Chapter 5.

4.1 COOLING TOWER INSTALLATION

The requirement to use plume-abated towers at SONGS increases the per-cell cost by a factor of approximately 2.9 over the cost of conventional tower cells (compared with the cost estimates for other facilities in this study). Table N–13 summarizes the design-and-build cost estimate for each tower developed by vendors, inclusive of all labor and management required for its installation.

The dry components of the plume-abated cooling towers were designed with titanium tubing instead of stainless steel. Titanium is more resistant to corrosion and performance losses that would result from continued exposure to salt drift from the tower. Use of stainless steel tubing would decrease the cost of the towers by a total of $27 million, but with additional maintenance costs and potentially diminished performance.

Table N–13. Wet Cooling Tower Design-and-Build Cost Estimate

	Unit 2	Unit 3	SONGS total
Number of cells	48	48	**96**
Cost/cell ($)	1,770,833	1,770,833	**1,770,833**
Total SONGS D&B Cost ($)	**85,000,000**	**85,000,000**	**170,000,000**

4.2 OTHER DIRECT COSTS

A significant portion of the cost incurred for the wet cooling tower installation results from the various support structures and materials (pipes, pumps, etc.), as well the necessary equipment and labor required to prepare the cooling tower site and connect the towers to the cooling system. At SONGS, these costs comprise approximately 50 percent of the initial capital cost. Line item costs are detailed in Appendix B.

Deviations from or additions to the general cost elements discussed in Chapter 5 are discussed below. Other direct costs (non–cooling tower) are summarized in Table N–14.

- *Civil, Structural, and Piping*
  The significant distances at which the cooling tower complexes must be placed from their respective units (approximately 3,500 feet for each complex), and the large size of the necessary pipes (144 inches), represent substantial increases in cost over an average facility. In total, the cooling tower configurations developed for SONGS require more than 19,000 feet of supply and return piping. An additional allowance is included in this category to reflect the installation of pipelines on a steep grade from the top of the bluffs to the beach.
- *Mechanical and Electrical*
  Initial capital costs in this category reflect incorporating new pumps (eight total) to circulate cooling water between the tower and condenser. No new pumps are required to provide makeup water from the Pacific Ocean. Electrical costs are based on the battery limit after the main feeder breakers.
- *Demolition*
  A small allowance is made for the demolition of the existing parking lot that will serve as the location for Tower Complex 1.

Table N–14. Summary of Other Direct Costs

	Equipment ($)	Bulk material ($)	Labor ($)	SONGS total ($)
Civil/structural/piping	13,900,000	68,500,000	40,700,000	**123,100,000**
Mechanical	25,100,000	0	1,900,000	**27,000,000**
Electrical	3,800,000	8,500,000	5,500,000	**17,800,000**
Demolition	0	0	100,000	**100,000**
Total SONGS other direct costs	**42,800,000**	**77,000,000**	**48,200,000**	**168,000,000**

4.3 INDIRECT AND CONTINGENCY

Indirect costs are calculated as 30 percent of all direct costs (civil/structural, mechanical, electrical, demolition, and cooling towers). An additional allowance is included for reinforcement of the condenser to withstand the increased pressures resulting from incorporating wet cooling towers. Each condenser may require reinforcement of the tube sheet bracing with 6-inch x 1-inch steel, and water box reinforcement/replacement with 5/8-inch carbon steel. Based on the data outlined in Chapter 5, a conservative estimate of 5 percent of all direct costs is included to account for possible condenser modifications. The location of the condensers (23 feet below grade) and the difficulty in accessing them for modifications may increase costs further, but cannot be evaluated within the scope of this study.

The contingency cost is calculated as 30 percent of the sum of all direct and indirect costs, including condenser reinforcement. At SONGS, potential costs in this category include relocation or demolition of small buildings and parking lots and the potential interference with underground structures, as well as the generally higher costs of construction projects at a secure nuclear facility. Disruption of coastal resources, if permitted, may require mitigation measures to allow the project to proceed. Soils were not characterized for this analysis. The instability of sandy soils may require additional pilings to support any large structures built at the site. Initial capital costs are summarized in Table N–15.

Table N–15. Summary of Initial Capital Costs

	Cost ($)
Cooling towers	170,000,000
Civil/structural/piping	123,100,000
Mechanical	27,000,000
Electrical	17,800,000
Demolition	100,000
Indirect cost	101,400,000
Condenser modification	16,900,000
Contingency	136,900,000
Total SONGS capital cost	**593,200,000**

4.4 SHUTDOWN

A significant portion of the work relating to installing wet cooling towers can be completed without major disruption to operations. The principal disruption to the output of one or both units will result from the time and complexity of condenser reinforcements and the time needed to integrate the new cooling system and conduct acceptance testing.

For SONGS, a conservative estimate of 6 months per unit was developed. As a baseload facility, SONGS is typically operational 90 to 95 percent of the year; the difference between "low" and "high" output months is not significant; thus, the period selected for shutdown is based on the time of year when SONGS is "least" critical to the grid. The lost revenue estimate for SONGS is based on the average replacement cost for the month(s) of shutdown (November through April), less the estimated cost of generation for a nuclear facility ($/MWh). The estimated revenue loss for SONGS is $595 million and summarized in Table N-16.

Table N–16. Estimated Revenue Loss from Construction Shutdown

Estimated output (MWh)	Production savings ($/MWh)	Replacement cost ($/MWh)	Gross replacement cost ($)	Revenue loss ($)
8,261,443	12	84	693,961,212	**594,823,896**

This analysis did not consider shutdown with respect to the required availability of a particular generating unit, nor can it automatically be assumed that the generating profile for 2006 will be the same in each subsequent year. Net output data from 2006 may not reflect any contractual obligations that mandate a particular unit's availability during a given time period.

4.5 OPERATIONS AND MAINTENANCE

O&M costs for a wet cooling tower system at SONGS include routine maintenance activities, chemicals and treatment systems to control fouling and corrosion in the towers, management and labor, and an allowance for spare parts and replacement. Annual costs are calculated based on the circulating water flow capacity of the towers using a base cost of $4.00/gpm in Year 1 and $5.80/gpm in Year 12, with an annual escalator of 2 percent (USEPA 2001). Year 12 costs increase based on the assumption that maintenance needs, particularly for spare parts and replacements, will be greater for years 12–20. Annual O&M costs, based on the design circulating water flow for the 12 cooling towers at SONGS (1,591,200 gpm), are presented in Table N–17. These costs reflect maximum operation.

Table N–17. Annual O&M Costs (Full Load)

	Year 1 ($)	Year 12 ($)
Management/labor	1,591,200	2,307,240
Service/parts	2,545,920	3,691,584
Fouling	2,227,680	3,230,136
Total SONGS O&M cost	**6,364,800**	**9,228,960**

4.6 ENERGY PENALTY

The energy penalty is divided into two components: increased parasitic use resulting from the additional electrical demand of cooling tower fans and pumps; and the decrease in thermal efficiency resulting from elevated turbine backpressure values. As discussed above, it is unlikely that SONGS will be able to alter operations to compensate for the shortfall in electricity production resulting from the energy penalty; any changes to generation output will be absorbed as a direct loss of revenue. The energy penalty for SONGS is calculated by first estimating the increased parasitic demand from the cooling tower pumps and fans, expressed as a percentage of the rated capacity of the particular unit(s). Likewise, the change in the unit's heat rate is also expressed as a capacity percentage. The sum of these values represents the percentage reduction in revenue-generating electricity SONGS will be able to produce with a wet cooling tower system.

4.6.1 INCREASED PARASITIC USE (FANS AND PUMPS)

As a baseload facility with an annual capacity utilization average of 85 percent or greater, SONGS will likely require the maximum cooling capacity of the wet cooling towers when the generating units are operational. During cooler periods of the year, SONGS may be able to take one or more cooling tower cells offline and still obtain the required cooling level. This would also reduce the fans' cumulative electrical demand. For the purposes of this study, however, operations are evaluated at the design conditions, i.e., maximum load; no allowance is made for seasonal changes. The increased electrical demand associated with operation of the cooling tower fans is summarized in Table N–18.

Table N–18. Cooling Tower Fan Parasitic Use

	Tower Complex 1	Tower Complex 2	SONGS total
Units served	Unit 2	Unit 3	--
Generating capacity (MW)	1,127	1,127	**2,254**
Number of fans (one per cell)	48	48	**96**
Motor power per fan (hp)	259	259	--
Total motor power (hp)	12,429	12,429	**24,858**
MW total	9.27	9.27	**18.54**
Fan parasitic use (% of capacity)	**0.82%**	**0.82%**	**0.82%**

The addition of new circulating water pump capacity for the wet cooling towers will also increase the parasitic use of electricity at SONGS. Makeup water will continue to be withdrawn from the Pacific Ocean through the use of one of the existing circulating water pumps; the remaining pumps will be retired. The net increase in pump-related parasitic usage is the difference between the new wet cooling tower configuration (new plus retained pumps) and the existing once-through configuration. Because one of the main design assumptions maintains the existing flow rate through each condenser, the new circulating pumps are single speed and are assumed to operate at their full rated capacity. The increased electrical demand associated with operating the cooling tower pumps is summarized in Table N–19.

Table N–19. Cooling Tower Pump Parasitic Use

	Tower Complex 1	Tower Complex 2	SONGS total
Units served	Unit 2	Unit 3	--
Generating capacity (MW)	1127	1127	**2,254**
Existing pump configuration (hp)	11,400	11,400	**22,800**
New pump configuration (hp)	38,200	38,200	**76,400**
Difference (hp)	26,800	26,800	**53,600**
Difference (MW)	20.0	20.0	**40.0**
Net pump parasitic use (% of capacity)	**1.77%**	**1.77%**	**1.77%**

4.6.2 HEAT RATE CHANGE

Adjustments to the heat rate were calculated based on the ambient conditions for each month and reflect the estimated difference between operations with once-through and wet cooling tower systems. As noted above, the energy penalty analysis assumes SONGS will absorb the financial loss associated with the reduction in revenue-generating electricity. The monthly percentage changes in the heat rate for each unit at SONGS are presented in Figure N–13 and Figure N–14.

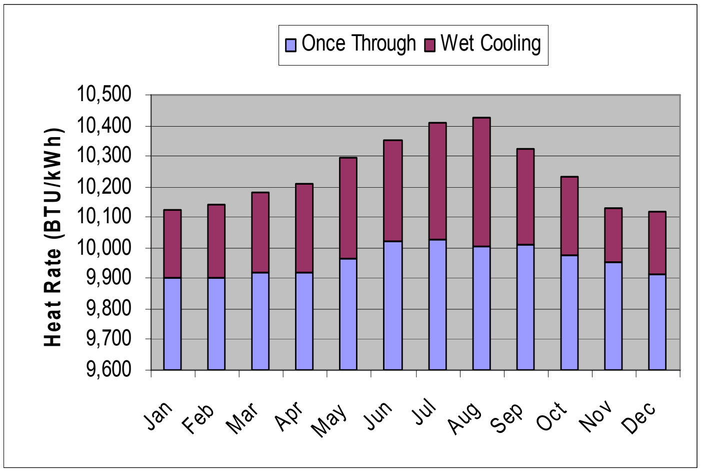

Figure N–13. Estimated Heat Rate Change (Unit 2)

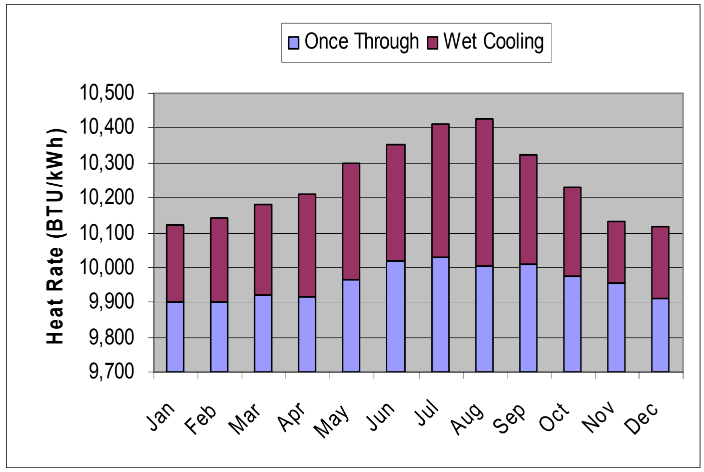

Figure N–14. Estimated Heat Rate Change (Unit 3)

4.6.3 CUMULATIVE ESTIMATE

The cost of the energy penalty for SONGS is calculated by first summing the three components of the penalty (efficiency + fan + pump), expressed as a percentage of the capacity, and multiplying this value by the net generation for each month. This yields the relative amount of revenue-generating electricity, expressed as MWh, that will be lost as a result of converting the once-through cooling system to wet cooling towers. The monthly cost is calculated using the average annual replacement cost ($84/MWh) obtained from the PG&E 2006 annual report. Based on 2006 net output, the monetary value of the annual energy penalty for SONGS will be approximately $80 million in Year 1. Table N–20 and Table N–21 summarize the Year 1 energy penalty estimates for each unit.

Table N–20. Unit 2 Energy Penalty—Year 1

Month	Replacement cost ($/MWh)	Net 2006 Generation (MWh)	Energy penalty				Generation shortfall (MWh)	Net Cost ($)
			Efficiency (%)	Fan (%)	Pump (%)	Total (%)		
January	84.00	712,715	2.22	0.82	1.77	4.82	34,336	2,884,246
February	84.00	545,288	2.39	0.82	1.77	4.99	27,206	2,285,276
March	84.00	0	2.63	0.82	1.77	5.23	0	0
April	84.00	730,296	2.95	0.82	1.77	5.54	40,470	3,399,445
May	84.00	820,213	3.35	0.82	1.77	5.95	48,808	4,099,842
June	84.00	804,330	3.37	0.82	1.77	5.97	47,981	4,030,439
July	84.00	826,713	3.83	0.82	1.77	6.43	53,154	4,464,948
August	84.00	832,706	4.21	0.82	1.77	6.81	56,670	4,760,316
September	84.00	806,706	3.16	0.82	1.77	5.76	46,457	3,902,347
October	84.00	835,284	2.59	0.82	1.77	5.19	43,336	3,640,233
November	84.00	809,927	1.78	0.82	1.77	4.38	35,470	2,979,444
December	84.00	842,201	2.06	0.82	1.77	4.66	39,250	3,297,001
							Unit 3 total	**39,743,537**

Table N–21. Unit 3 Energy Penalty—Year 1

Month	Replacement cost ($/MWh)	Net 2006 Generation (MWh)	Energy penalty				Generation shortfall (MWh)	Net Cost ($)
			Efficiency (%)	Fan (%)	Pump (%)	Total (%)		
January	84.00	837,731	2.22	0.82	1.77	4.82	40,359	3,390,168
February	84.00	754,393	2.39	0.82	1.77	4.99	37,638	3,161,627
March	84.00	755,515	2.63	0.82	1.77	5.23	39,512	3,319,008
April	84.00	730,296	2.95	0.82	1.77	5.54	40,470	3,399,445
May	84.00	763,024	3.35	0.82	1.77	5.95	45,405	3,813,983
June	84.00	807,492	3.37	0.82	1.77	5.97	48,170	4,046,283
July	84.00	828,197	3.83	0.82	1.77	6.43	53,250	4,472,963
August	84.00	835,310	4.21	0.82	1.77	6.81	56,848	4,775,202
September	84.00	807,408	3.16	0.82	1.77	5.76	46,497	3,905,743
October	84.00	737,869	2.59	0.82	1.77	5.19	38,282	3,215,692
November	84.00	0	1.78	0.82	1.77	4.38	0	0
December	84.00	712,715	2.06	0.82	1.77	4.66	33,215	2,790,096
							Unit 3 total	**40,290,210**

4.7 NET PRESENT COST

The Net Present Cost (NPC) of a wet cooling system retrofit at SONGS is the sum of all annual expenditures over the 20-year life span of the project, discounted according to the year in which the expense is incurred, and the selected discount rate. The NPC represents the total change in revenue streams, in 2007 dollars, that SONGS can expect over 20 years as a direct result of converting to wet cooling towers. The following values were used to calculate the NPC at a 7 percent discount rate:

- *Capital and Start-up.* Includes all capital, indirect, contingency, and shutdown costs. All costs in this category are incurred in Year 0. (See Table N–15 and Table N–16.)
- *Annual O&M*. Base cost values for Year 1 and Year 12 are adjusted for subsequent years using a 2 percent year-over-year escalator. Because SONGS is a baseload facility and operates at a relatively high capacity utilization factor, O&M costs for the NPC calculation were estimated at 100 percent of their maximum value. (See Table N–17.)
- *Annual Energy Penalty.* As a baseload facility, SONGS can be expected to operate at a high capacity utilization rate over its remaining life span. This study uses the 5-year average MWh output (2001–2006) as the basis for calculating the energy penalty in Years 1 through 20, including a year-over-year wholesale price escalation of 5.8 percent (based on the Producer Price Index). (See Table N–20 and Table N–21.)

Using these values, the NPC20 for SONGS is $2,621 million. Appendix C contains detailed annual calculations used to develop this cost.

4.8 ANNUAL COST

The annual cost incurred by SONGS for the retrofit of the once-through cooling system is the sum of the annual amortized capital cost plus the annual average of O&M and energy penalty expenditures. Capital costs are amortized at a 7 percent discount rate over 20 years. O&M and energy penalty costs are calculated in the same manner as for the NPC_{20} (Section Table N–22).

Table N–22. Annual Cost

Discount rate (%)	Capital ($)	Annual O&M ($)	Annual energy penalty ($)	Annual cost ($)
7.00	56,000,000	8,400,000	144,500,000	**208,900,000**

4.9 COST-TO-GROSS REVENUE COMPARISON

Financial data available to conduct a detailed analysis of the economic impact that a wet cooling system retrofit will have on annual revenues for SGS are limited. As an investor-owned utility, SCE's gross revenues will include costs for transmission and distribution. An approximation of gross annual revenues was calculated using public data sources (US EIA 2005) that showed SCE's average annual retail rate was $125/MWh. This rate was applied to the monthly net generating outputs for each unit in 2006 (CEC 2006) to arrive at a facility-wide revenue estimate.

This estimate does not reflect seasonal adjustments that may translate to higher or lower per-MWh retail rates through the year, nor does it include other liabilities such as taxes or other operational costs.

The estimated gross revenue for SONGS is summarized in Table N–23. A comparison of annual costs to annual gross revenue is summarized in Table N–24.

Table N–23. Estimated Gross Revenue

	Retail rate ($/MWh)	Net generation (MWh)		Estimated gross revenue ($)		
		Unit 2	Unit 3	Unit 2	Unit 3	SONGS total
January	125	712,715	837,731	89,089,350	104,716,375	**193,805,725**
February	125	545,288	754,393	68,160,960	94,299,125	**162,460,085**
March	125	0	755,515	0	94,439,375	**94,439,375**
April	125	730,296	730,296	91,287,000	91,287,000	**182,574,000**
May	125	820,213	763,024	102,526,625	95,378,010	**197,904,635**
June	125	804,330	807,492	100,541,250	100,936,500	**201,477,750**
July	125	826,713	828,197	103,339,125	103,524,625	**206,863,750**
August	125	832,706	835,310	104,088,250	104,413,750	**208,502,000**
September	125	806,706	807,408	100,838,250	100,926,000	**201,764,250**
October	125	835,284	737,869	104,410,500	92,233,680	**196,644,180**
November	125	809,927	0	101,240,875	0	**101,240,875**
December	125	842,201	712,715	105,275,125	89,089,350	**194,364,475**
	SONGS total	**8,566,379**	**8,569,950**	**1,070,797,310**	**1,071,243,790**	**2,142,041,100**

Table N–24. Cost-Revenue Comparison

Estimated gross annual revenue ($)	Initial capital		O&M		Energy penalty		Total annual cost	
	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross
2,142,000,000	56,000,000	2.6	8,400,000	0.4	144,500,000	6.7	**208,900,000**	**9.8**

5.0 OTHER TECHNOLOGIES

Within the scope of this study, and using the OPC resolution's stated goal of reducing impingement and entrainment by 90–95 percent as a benchmark, the effectiveness of other technologies commonly used to address such impacts could not be conclusively determined for use at SONGS. As with many existing facilities, the location and configuration of the site complicates the use of some technologies that might be used successfully elsewhere. A more detailed analysis that also comprises a biological evaluation may determine the applicability of one or more of these technologies to SONGS. A brief summary of the applicability of these technologies follows.

5.1 MODIFIED RISTROPH SCREENS—FINE MESH

The principal concern with this technology is the successful return of viable organisms captured on the screens to the source water body. SONGS currently withdraws its cooling water through a submerged conduit extending approximately 3,100 feet offshore at a depth of 35 feet. Returning any collected organisms to a similar location would be impractical. It is unclear whether organisms could be returned to a near-shore location closer to the facility and remain viable.

5.2 BARRIER NETS

Barrier nets are unproven in an open ocean environment.

5.3 AQUATIC FILTRATION BARRIERS

Aquatic filtration barriers (AFBs) are unproven in an open ocean environment.

5.4 VARIABLE SPEED DRIVES

Variable speed drives (VSDs) were not considered for analysis at SONGS because the technology alone cannot be expected to achieve the desired level of reductions in impingement and entrainment, nor could it be combined with another technology to yield the desired reductions.

Pumps that have been retrofitted with VSDs can reduce overall flow intake volumes by 10–35 percent over the current once-through configuration (USEPA 2001). The actual reduction, however, will vary based on the cooling water demand at different times of the year. At peak demand, the pumps will essentially function as standard circulating water pumps and withdraw water at the maximum rated capacity, negating any potential benefit. Use of VSDs may be an economically desirable option when pumps are retrofitted or replaced for other reasons, but were not considered further for this study.

5.5 CYLINDRICAL FINE-MESH WEDGEWIRE

Fine-mesh cylindrical wedgewire screens have not been deployed or evaluated at open coastal facilities for applications as large as required at SONGS (approximately 2,300 mgd). To function as intended, cylindrical wedgewire screens must be submerged in a water body with a consistent ambient current of 0.5 fps. Ideally, this current would be unidirectional so that screens may be oriented properly and any debris impinged on the screens will be carried downstream when the airburst cleaning system is activated.

Fine-mesh wedgewire screens for SONGS would be located offshore in the Pacific Ocean, west of the facility. Information regarding the subsurface currents in the near-shore environment close to SONGS is limited. Data suggest that these currents are multidirectional, depending on the tide and season, and fluctuate in terms of velocity, with prolonged periods below 0.5 fps (SCCOOS 2006).

To attain sufficient depth (approximately 20 feet) and an ambient current that might allow deployment, screens would need to be located 2,000 feet or more offshore. Discussions with vendors who design these systems indicated that distances more than 1,000 to 1,500 feet become problematic due to the inability of the airburst system to maintain adequate pressure for sufficient cleaning (Someah 2007). Together, these considerations preclude further evaluation of fine-mesh cylindrical wedgewire screens at SONGS.

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Appendix A. Once-Through and Closed-Cycle Thermal Performance

		Unit 2			Unit 3		
		Once through	Closed cycle	Net increase	Once through	Closed cycle	Net increase
JAN	Backpressure (in. HgA)	1.97	2.56	**0.58**	1.97	2.56	**0.58**
	Heat rate Δ (%)	*-0.39*	*1.83*	***2.22***	*-0.39*	*1.83*	***2.22***
FEB	Backpressure (in. HgA)	1.98	2.60	**0.62**	1.98	2.60	**0.62**
	Heat rate Δ (%)	*-0.38*	*2.01*	***2.39***	*-0.38*	*2.01*	***2.39***
MAR	Backpressure (in. HgA)	2.04	2.69	**0.65**	2.04	2.69	**0.65**
	Heat rate Δ (%)	*-0.21*	*2.42*	***2.63***	*-0.21*	*2.42*	***2.63***
APR	Backpressure (in. HgA)	2.03	2.75	**0.72**	2.03	2.75	**0.72**
	Heat rate Δ (%)	*-0.24*	*2.71*	***2.95***	*-0.24*	*2.71*	***2.95***
MAY	Backpressure (in. HgA)	2.17	2.95	**0.78**	2.17	2.95	**0.78**
	Heat rate Δ (%)	*0.23*	*3.59*	***3.35***	*0.23*	*3.59*	***3.35***
JUN	Backpressure (in. HgA)	2.32	3.09	**0.77**	2.32	3.09	**0.77**
	Heat rate Δ (%)	*0.79*	*4.16*	***3.37***	*0.79*	*4.16*	***3.37***
JUL	Backpressure (in. HgA)	2.34	3.23	**0.89**	2.34	3.23	**0.89**
	Heat rate Δ (%)	*0.90*	*4.73*	***3.83***	*0.90*	*4.73*	***3.83***
AUG	Backpressure (in. HgA)	2.28	3.27	**0.99**	2.28	3.27	**0.99**
	Heat rate Δ (%)	*0.66*	*4.87*	***4.21***	*0.66*	*4.87*	***4.21***
SEP	Backpressure (in. HgA)	2.29	3.02	**0.72**	2.29	3.02	**0.72**
	Heat rate Δ (%)	*0.70*	*3.86*	***3.16***	*0.70*	*3.86*	***3.16***
OCT	Backpressure (in. HgA)	2.20	2.80	**0.60**	2.20	2.80	**0.60**
	Heat rate Δ (%)	*0.34*	*2.94*	***2.59***	*0.34*	*2.94*	***2.59***
NOV	Backpressure (in. HgA)	2.15	2.58	**0.43**	2.15	2.58	**0.43**
	Heat rate Δ (%)	*0.15*	*1.94*	***1.78***	*0.15*	*1.94*	***1.78***
DEC	Backpressure (in. HgA)	2.01	2.55	**0.54**	2.01	2.55	**0.54**
	Heat rate Δ (%)	*-0.29*	*1.77*	***2.06***	*-0.29*	*1.77*	***2.06***

Note: Heat rate delta represents change from design value calculated according to estimated ambient conditions for each month.

Appendix B. Itemized Capital Costs

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
CIVIL / STRUCTURAL / PIPING	--	--	--	--	--	--	--	--	--	--
Allocation for additional costs for installing pipes in steep hill	lot	1	--	--	1,000,000	1,000,000	10,000.00	100	1,000,000	**2,000,000**
Allocation for other accessories (bends, water hammers…)	lot	1	--	--	500,000	500,000	4,000.00	85	340,000	**840,000**
Allocation for pipe racks (approx 1200 ft) and cable racks	t	120	--	--	2,500	300,000	17.00	105	214,200	**514,200**
Allocation for sheet piling and dewatering	lot	1	--	--	2,500,000	2,500,000	25,000.00	100	2,500,000	**5,000,000**
Allocation for testing pipes	lot	2	--	--	--	--	2,000.00	95	380,000	**380,000**
Allocation for Tie-Ins to existing condenser's piping	lot	1	--	--	250,000	250,000	2,000.00	85	170,000	**420,000**
Allocation for trust blocks	lot	1	--	--	50,000	50,000	500.00	95	47,500	**97,500**
Backfill for PCCP pipe (reusing excavated material)	m3	88,365	--	--	--	--	0.04	200	706,920	**706,920**
Bedding for PCCP pipe	m3	63,365	--	--	25	1,584,125	0.04	200	506,920	**2,091,045**
Bend for PCCP pipe 120" diam (allocation)	ea	10	--	--	35,000	350,000	100.00	95	95,000	**445,000**
Bend for PCCP pipe 144" diam. (allocation)	ea	35	--	--	75,000	2,625,000	180.00	95	598,500	**3,223,500**
Bend for PCCP pipe 42" & 48" diam (allocation)	ea	34	--	--	5,000	170,000	25.00	95	80,750	**250,750**
Building architectural (siding, roofing, doors, painting…etc)	ea	4	--	--	250,000	1,000,000	3,000.00	95	1,140,000	**2,140,000**
Butterfly valves 120" c/w allocation for actuator & air lines	ea	4	252,000	1,008,000	--	--	80.00	85	27,200	**1,035,200**
Butterfly valves 144" c/w allocation for actuator & air lines	ea	12	429,000	5,148,000	--	--	100.00	85	102,000	**5,250,000**
Butterfly valves 30" c/w allocation for actuator & air lines	ea	96	30,800	2,956,800	--	--	50.00	85	408,000	**3,364,800**
Butterfly valves 48" c/w allocation for actuator & air lines	ea	10	46,200	462,000	--	--	50.00	85	42,500	**504,500**
Butterfly valves 96" c/w allocation for actuator & air lines	ea	16	151,200	2,419,200	--	--	75.00	85	102,000	**2,521,200**
Check valves 48"	ea	2	66,000	132,000	--	--	24.00	85	4,080	**136,080**
Check valves 96"	ea	8	216,000	1,728,000	--	--	40.00	85	27,200	**1,755,200**
Concrete basin walls (all in)	m3	1,869	--	--	225	420,525	8.00	75	1,121,400	**1,541,925**
Concrete elevated slabs (all in)	m3	1,702	--	--	250	425,500	10.00	75	1,276,500	**1,702,000**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Concrete for transformers and oil catch basin (allocation)	m3	200	--	--	250	50,000	10.00	75	150,000	**200,000**
Concrete slabs on grade (all in)	m3	16,075	--	--	200	3,215,000	4.00	75	4,822,500	**8,037,500**
Ductile iron cement pipe 12" diam. for fire water line	ft	6,000	--	--	100	600,000	0.60	95	342,000	**942,000**
Excavation and backfill for fire line, blowdown & make-up (using excavated material for backfill except for bedding)	m3	21,785	--	--	--	--	0.08	200	348,560	**348,560**
Excavation for PCCP pipe	m3	####	--	--	--	--	0.04	200	1,794,080	**1,794,080**
Fencing around transformers	m	50	--	--	30	1,500	1.00	75	3,750	**5,250**
Flange for PCCP joints 120"	ea	12	--	--	39,795	477,540	40.00	95	45,600	**523,140**
Flange for PCCP joints 144"	ea	24	--	--	68,000	1,632,000	75.00	95	171,000	**1,803,000**
Flange for PCCP joints 30"	ea	96	--	--	2,260	216,960	16.00	95	145,920	**362,880**
Flange for PCCP joints 42"	ea	2	--	--	3,270	6,540	18.00	95	3,420	**9,960**
Foundations for pipe racks and cable racks	m3	280	--	--	250	70,000	8.00	75	168,000	**238,000**
FRP flange 30"	ea	288	--	--	1,679	483,595	50.00	85	1,224,000	**1,707,595**
FRP flange 48"	ea	26	--	--	3,000	78,000	75.00	85	165,750	**243,750**
FRP flange 96"	ea	56	--	--	40,000	2,240,000	500.00	85	2,380,000	**4,620,000**
FRP pipe 96" diam.	ft	400	--	--	2,838	1,135,200	1.75	85	59,500	**1,194,700**
Harness clamp 120" c/w internal testable joint for PCCP pipe	ea	250	--	--	4,310	1,077,500	25.00	95	593,750	**1,671,250**
Harness clamp 144" c/w internal testable joint	ea	1,300	--	--	5,275	6,857,500	30.00	95	3,705,000	**10,562,500**
Harness clamp 42" & 48" c/w internal testable joint	ea	340	--	--	2,000	680,000	16.00	95	516,800	**1,196,800**
Joint for FRP pipe 96" diam.	ea	20	--	--	17,974	359,480	600.00	85	1,020,000	**1,379,480**
PCCP pipe 120" diam.	ft	4,000	--	--	1,285	5,140,000	3.50	95	1,330,000	**6,470,000**
PCCP pipe 144" diam.	ft	15,200	--	--	1,820	27,664,000	5.00	95	7,220,000	**34,884,000**
PCCP pipe 42" dia.for blowdown	ft	400	--	--	195	78,000	0.90	95	34,200	**112,200**
PCCP pipe 48" dia. for make-up water line	ft	6,400	--	--	260	1,664,000	1.00	95	608,000	**2,272,000**
Riser (FRP pipe 30" diam X55 ft)	ea	96	--	--	15,350	1,473,580	150.00	85	1,224,000	**2,697,580**
Structural steel for building	t	840	--	--	2,500	2,100,000	20.00	105	1,764,000	**3,864,000**
CIVIL / STRUCTURAL / PIPING TOTAL	**--**	**--**	**--**	**13,854,000**	**--**	**68,475,546**	**--**	**--**	**40,730,500**	**123,060,046**
DEMOLITION	--	--	--	--	--	--	--	--	--	--
Demolition of parking lot	ea	1	--	--	--	--	1,000.00	100	100,000	**100,000**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
DEMOLITION TOTAL	--	--	--	**0**	--	**0**	--	--	**100,000**	**100,000**
ELECTRICAL	--	--	--	--	--	--	--	--	--	--
4.16 kv cabling feeding MCC's	m	4,000	--	--	75	300,000	0.40	85	136,000	**436,000**
4.16kV switchgear - 8 breakers	ea	1	350,000	350,000	--	--	250.00	85	21,250	**371,250**
480 volt cabling feeding MCC's	m	2,000	--	--	70	140,000	0.40	85	68,000	**208,000**
480V Switchgear - 1 breaker 3000A	ea	16	30,000	480,000	--	--	80.00	85	108,800	**588,800**
Allocation for automation and control	lot	1	--	--	2,000,000	2,000,000	20,000.00	85	1,700,000	**3,700,000**
Allocation for cable trays and duct banks	m	7,000	--	--	75	525,000	1.00	85	595,000	**1,120,000**
Allocation for lighting and lightning protection	lot	1	--	--	200,000	200,000	2,000.00	85	170,000	**370,000**
Dry Transformer 2MVA xxkV-480V	ea	16	100,000	1,600,000	--	--	100.00	85	136,000	**1,736,000**
Lighting & electrical services for pump house building	ea	4	--	--	90,000	360,000	1,000.00	85	340,000	**700,000**
Local feeder for 250 HP motor 460 V (up to MCC)	ea	96	--	--	18,000	1,728,000	150.00	85	1,224,000	**2,952,000**
Local feeder for 7000 HP motor 4160 V (up to MCC)	ea	8	--	--	60,000	480,000	250.00	85	170,000	**650,000**
Oil Transformer 20MVA xx-4.16kV	ea	4	250,000	1,000,000	--	--	200.00	85	68,000	**1,068,000**
Primary breaker(xxkV)	ea	8	45,000	360,000	--	--	60.00	85	40,800	**400,800**
Primary feed cabling (assumed 13.8 kv)	m	16,000	--	--	175	2,800,000	0.50	85	680,000	**3,480,000**
ELECTRICAL TOTAL	--	--	--	**3,790,000**	--	**8,533,000**	--	--	**5,457,850**	**17,780,850**
MECHANICAL	--	--	--	--	--	--	--	--	--	--
Allocation for ventilation of buildings	ea	4	100,000	400,000	--	--	1,000.00	85	340,000	**740,000**
Cooling tower for unit 2	lot	1	85,000,000	85,000,000	--	--	--	--	--	**85,000,000**
Cooling tower for unit 3	lot	1	85,000,000	85,000,000	--	--	--	--	--	**85,000,000**
Overhead crane 50 ton in (in pump house) Including additional structure to reduce the span	ea	4	500,000	2,000,000	--	--	1,000.00	85	340,000	**2,340,000**
Pump 4160 V 2000 HP	ea	4	1,000,000	4,000,000	--	--	500.00	85	170,000	**4,170,000**
Pump 4160 V 7000 HP	ea	10	1,870,000	18,700,000	--	--	1,200.00	85	1,020,000	**19,720,000**
MECHANICAL TOTAL	--	--	--	**195,100,000**	--	**0**	--	--	**1,870,000**	**196,970,000**

Appendix C. Net Present Cost Calculation

Project year	Capital/start-up ($)	O & M ($)	Energy penalty ($)		Total ($)	Annual discount factor	Present value ($)
			Unit 1	Unit 2			
0	1,187,823,896	--	--	--	1,187,823,896	1	**1,187,823,896**
1	--	6,364,800	39,743,538	40,290,210	86,398,548	0.9346	**80,748,083**
2	--	6,492,096	42,060,586	42,639,130	91,191,812	0.8734	**79,646,929**
3	--	6,621,938	44,512,718	45,124,991	96,259,647	0.8163	**78,576,750**
4	--	6,754,377	47,107,810	47,755,778	101,617,964	0.7629	**77,524,345**
5	--	6,889,464	49,854,195	50,539,940	107,283,599	0.713	**76,493,206**
6	--	7,027,253	52,760,695	53,486,418	113,274,367	0.6663	**75,474,710**
7	--	7,167,799	55,836,643	56,604,677	119,609,118	0.6227	**74,480,598**
8	--	7,311,155	59,091,920	59,904,729	126,307,803	0.582	**73,511,141**
9	--	7,457,378	62,536,978	63,397,175	133,391,531	0.5439	**72,551,654**
10	--	7,606,525	66,182,884	67,093,230	140,882,640	0.5083	**71,610,646**
11	--	7,758,656	70,041,346	71,004,765	148,804,768	0.4751	**70,697,145**
12	--	9,413,539	74,124,757	75,144,343	158,682,639	0.444	**70,455,092**
13	--	9,601,810	78,446,230	79,525,259	167,573,299	0.415	**69,542,919**
14	--	9,793,846	83,019,645	84,161,581	176,975,073	0.3878	**68,630,933**
15	--	9,989,723	87,859,691	89,068,201	186,917,615	0.3624	**67,738,944**
16	--	10,189,518	92,981,911	94,260,877	197,432,306	0.3387	**66,870,322**
17	--	10,393,308	98,402,756	99,756,287	208,552,351	0.3166	**66,027,674**
18	--	10,601,174	104,139,637	105,572,078	220,312,889	0.2959	**65,190,584**
19	--	10,813,198	110,210,978	111,726,930	232,751,105	0.2765	**64,355,681**
20	--	11,029,462	116,636,278	118,240,610	245,906,349	0.2584	**63,542,201**
Total							**2,621,493,453**

O. Scattergood Generating Station

Los Angeles Dept. of Water and Power—Los Angeles, CA

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Appendices

1.0 GENERAL SUMMARY

Retrofitting the existing once-through cooling system at Scattergood Generating Station (SGS) with closed-cycle wet cooling towers is technically and logistically feasible based on this study's design criteria, and will reduce cooling water withdrawals from Santa Monica Bay by approximately 95 percent. Impingement and entrainment impacts would be reduced by a similar proportion.

The proximity SGS to the south runway at Los Angeles International Airport (LAX) will likely require incorporating plume abatement technologies into any final tower design. The preferred option selected for SGS includes 4 plume-abated wet cooling towers with individual cells arranged in an inline configuration to accommodate limited space at the site.

Construction-related shutdowns are estimated to take approximately 4 weeks per unit (concurrent), although SGS is not expected to incur any financial loss as a result based on 2006 capacity utilization rates for all units. The cooling tower configuration designed under the preferred option complies with all identified local use restrictions and includes necessary mitigation measures, where applicable.

1.1 COST

Initial capital and net presents costs associated with the installation and operation of wet cooling towers at SGS are summarized in Table O–1. Annualized costs based on 20-year average values for the various cost elements are summarized in Table O–2. A detailed cost analysis is presented in Section 4.0 of this chapter.

Table O–1. Cumulative Cost Summary

Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2005 output) ($/MWh)
Total capital and start-up [a]	160,500,000	22.82	107
NPV_{20} [b]	193,700,000	27.54	129

[a] Includes all costs associated with the construction and installation of cooling towers and shutdown loss, if any.
[b] NPV_{20} includes all capital costs, operation and maintenance costs, and energy penalty costs over 20 years discounted at 7 percent.

Table O–2. Annual Cost Summary

Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2005 output) ($/MWh)
Capital and start-up [a]	15,200,000	2.16	10.15
Operations and maintenance	900,000	0.13	0.60
Energy penalty	2,600,000	0.37	1.74
Total SGS annual cost	**18,700,000**	**2.66**	**12.49**

[a] Does not include revenue loss associated with shutdown, if any, which is incurred in Year 0 only.

1.2 ENVIRONMENTAL

Environmental changes associated with a cooling tower retrofit for SGS are summarized in Table O–3 and discussed further in Section 3.4.

Table O–3. Environmental Summary

		Unit 1	Unit 2	Unit 3
Water use	Design intake volume (gpm)	78,000	78,000	188,000
	Cooling tower makeup water (gpm)	3,400	3,400	9,000
	Reduction from capacity (%)	96	96	95
Energy efficiency [a]	Summer heat rate increase (%)	1.28	1.28	1.35
	Summer energy penalty (%)	2.61	2.61	3.84
	Annual heat rate increase (%)	1.27	1.27	1.19
	Annual energy penalty (%)	2.60	2.60	3.68
Direct air emissions [b]	PM_{10} emissions (tons/yr) (maximum capacity)	45	45	108
	PM_{10} emissions (tons/yr) (2005 capacity utilization)	6.3	18.4	17.7

[a] Reflects the comparative increase between once-through and wet cooling systems, but does not account for any operational changes to address the change in efficiency, such as increased fuel consumption (see Section 4.6).
[b] Reflects emissions from the cooling tower only; does not include any increase in stack emissions.

1.3 OTHER POTENTIAL FACTORS

Considerations outside this study's scope may limit the practicality or overall feasibility of a wet cooling tower retrofit at Scattergood.

The final location selected for the Unit 1 and Unit 2 cooling towers will likely require modifications to, or relocation of, the existing switchyard to minimize interference resulting from drift deposition. The selected design of plume-abated towers described in this chapter represents the most plausible installation that can be developed for the SGS based on the information available. Options not considered in this study, such as the relocation of the switchyard, might make alternative configurations more feasible. Constraints on placement and design are discussed further in Section 3.2.3.

2.0 BACKGROUND

The Scattergood Generating Station (SGS) is a natural gas–fired steam electric generating facility located in the city of Los Angeles, Los Angeles County, owned and operated by the Los Angeles Department of Water and Power (LADWP). SGS currently operates three conventional steam turbine units (Unit 1, Unit 2, and Unit 3) with a combined generating capacity of 803 MW. The facility occupies approximately 56 acres of an industrial site across Vista del Mar from Dockweiler State Beach and Santa Monica Bay. A portion of the northern boundary of the property borders the City of Los Angeles Hyperion Wastewater Treatment Plant (WWTP) (Figure O–1).

Table O–4. General Information

Unit	In-service year	Rated capacity (MW)	2005 capacity utilization [a]	Condenser cooling water flow (gpm)
Unit 1	1958	179	26.4%	78,000
Unit 2	1959	179	29.7%	78,000
Unit 3	1974	445	20.6%	188,000
SGS total		**803**	**23.9%**	**344,000**

[a] *Quarterly Fuel and Energy Report—2005* (CEC 2005).

Figure O–1. General Vicinity of Scattergood Generating Station

2.1 COOLING WATER SYSTEM

SGS operates one cooling water intake structure (CWIS) to provide condenser cooling water to the three generating units (Figure O–2). Once-through cooling water is combined with low-volume wastes generated by SGS and discharged through a single submerged outfall to the Pacific Ocean, located approximately 1,200 feet offshore at a depth of 11 feet. Surface water withdrawals and discharges are regulated by NPDES Permit CA0000370, as implemented by Los Angeles Regional Water Quality Control Board (LARWQCB) Order 00-083.[1]

Cooling water is obtained from the Pacific Ocean through a submerged intake conduit terminating 1,600 feet offshore at a depth of approximately 15 feet. The submerged end of the conduit is fitted with a velocity cap to minimize the entrainment of motile fish into the system by converting the vertical flow to a lateral flow, thus triggering a flight response from fish.

The onshore portion of the CWIS comprises eight screen bays, each fitted with a vertical traveling screen with 3/8-inch by 3/4-inch mesh panels. Four screen bays serve Unit 3, while the remaining four are divided between Unit 1 and Unit 2 (two each). Screens are rotated manually every 8 hours. A high-pressure spray removes any debris or fish that have become impinged on the screen face. Captured debris is collected in a dumpster for disposal in a landfill. Downstream of each screen is a circulating water pump. The pumps for Unit 1 and Unit 2 are each rated at 39,000 gallons per minute (gpm), or 56 million gallons per day (mgd). The four pumps for Unit 3 are each rated at 47,000 gpm, or 68 mgd. The total facility capacity is 344,000 gpm, or 495 mgd (LADWP 2005).

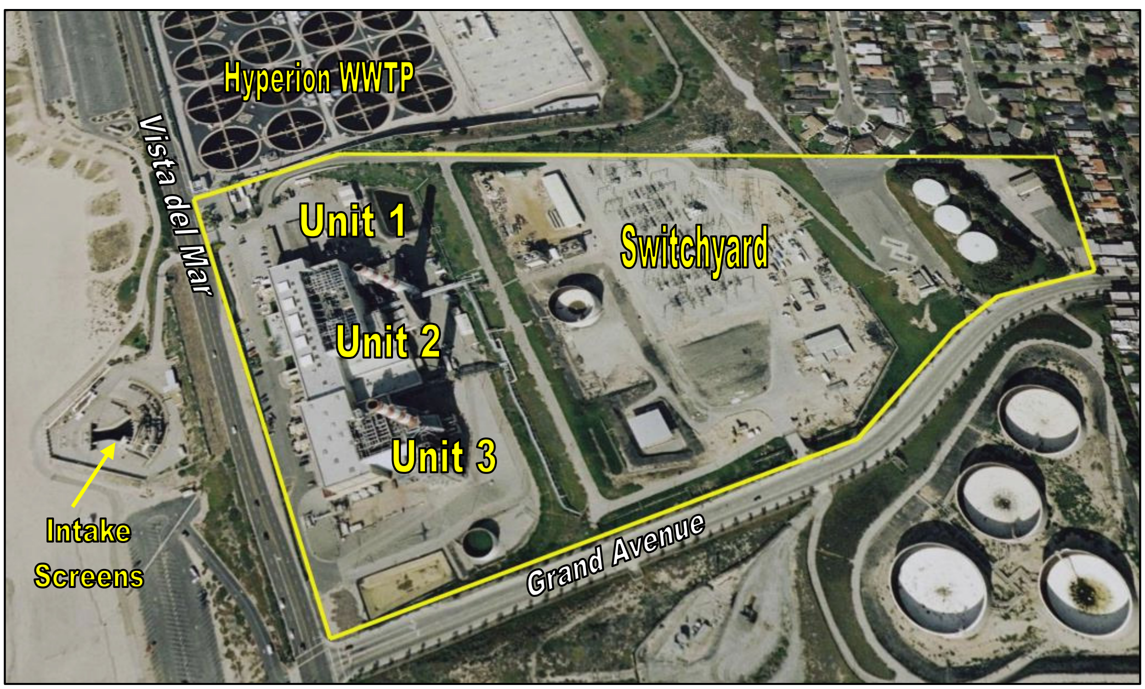

Figure O–2. Site View

[1] LARWQCB Order 00-083 expired on May 10, 2005, but has been administratively extended pending adoption of a renewed order.

At maximum capacity, SGS maintains a total pumping capacity rated at 495 mgd. On an annual basis, SGS withdraws substantially less than its design capacity due to its low generating capacity utilization (23.9 percent for 2005).[2] When in operation and generating the maximum load, SGS can be expected to withdraw water from the Pacific Ocean at a rate approaching its maximum capacity.

2.2 SECTION 316(B) PERMIT COMPLIANCE

The CWIS currently in operation at SGS uses a velocity cap to reduce the entrainment of motile fish through the system, although it is commonly thought of as an impingement-reduction technology because it targets larger organisms. Velocity caps have been shown to reduce impingement rates when compared with a shoreline intake structure. Likewise, the location of the intake structure in an offshore setting may contribute to lower rates of entrainment when compared with a shoreline intake if the near-shore environment is more biologically productive. This study did not evaluate the effectiveness of either measure.

LARWQCB Order 00-083 references an ecological study conducted by SGS from 1977 to 1981 to determine whether the CWIS was compliant with Section 316(b) of the Clean Water Act. Finding 8 of the order, adopted in 2000, notes:

> …the study…adequately addressed the important ecological and engineering factors specified in the guidelines, demonstrated that the ecological impacts of the intake system are environmentally acceptable, and provided evidence that no modifications to design, location, or capacity of the intake structure are required. (LARWQCB 2000, Finding 8)

The order does not contain any numeric or narrative limitations regarding impingement or entrainment resulting from CWIS operation, but does require semiannual monitoring of impingement at the intake structure (coinciding with scheduled heat treatments). Based on the record available for review, SGS has been compliant with this permit requirement.

The LARWQCB has notified SGS of its intent to revisit requirements under CWA Section 316(b), including a determination of best technology available (BTA) for minimization of adverse environmental impact, during the current permit reissuance process. A final decision regarding any Section 316(b)–related requirements has not been made as of the publication of this study.

[2] Unit-level generating data for 2006 were not available for SGS. All capacity utilization references in this chapter refer to 2005 output.

3.0 WET COOLING SYSTEM RETROFIT

3.1 OVERVIEW

This study evaluates the use of saltwater wet cooling towers at SGS, with the current source water (Pacific Ocean) continuing to provide makeup water to the facility. Conversion of the existing once-through cooling system to wet cooling towers will reduce the facility's current intake capacity by approximately 95 percent; rates of impingement and entrainment will decline by a similar proportion. Use of alternative water sources as a replacement for the once-through cooling water currently used at SGS is a potentially feasible option based on the volume of secondary treated water available in the vicinity. In a wet cooling tower system, the use of reclaimed water as the makeup water source (as opposed to the Pacific Ocean) is an attractive alternative when considering additional benefits its use may provide, such as avoidance of conflicts with effluent limitations or air emission standards. Use of reclaimed water is discussed further in Section 3.4.4.

The configuration of the wet cooling towers—their size and location—was based on best professional judgment (BPJ) using the criteria outlined in Chapter 5 and designed to meet the performance benchmarks in the most cost-effective manner. Information not available to this study that offers a more complete characterization of the facility may lead to different conclusions regarding the physical configuration of the towers.

This study developed a conceptual design of wet cooling towers sufficient to meet the cooling demand for each active generating unit at SGS at its rated output during peak climate conditions. Cost estimates are based on vendor quotes developed using the available information and the various design constraints identified at SGS.

The overall practicality of retrofitting the three units at SGS will require an evaluation of factors outside the scope of this study, such as the age and efficiency of the units and their role in the overall reliability of electricity production and transmission in California, particularly the Los Angeles region.

3.2 DESIGN BASIS

3.2.1 CONDENSER SPECIFICATIONS

For this study, the conceptual design of the cooling towers selected for SGS is based on the assumption that the condenser flow rate and thermal load to each will remain unchanged from the current system. Although no provision is included to re-optimize the condenser performance for service with a cooling tower, some modifications to the condenser (tube sheet and water box reinforcement) may be necessary to handle the increased water pressures that will result from the increased total pump head required to raise water to the elevation of the cooling tower risers.[3] The practicality and difficulty of these modifications are dependent on the age and configuration of each unit, but are assumed to be feasible at SGS. Condenser water boxes for all three units are

[3] In this context, re-optimization refers to a comprehensive overhaul of the condenser, such as re-tubing or converting the flow from single to multiple passes. Modifications are generally limited to reinforcement measures to enable the condenser to withstand the increased pressures.

located at grade level and appear to be readily accessible. Additional costs associated with condenser modifications are included in the discussion of capital expenditures (Section 4.3).

Information provided by SGS was largely used as the basis for the cooling tower design. In some cases, the data were incomplete or conflicted with values obtained from other sources. Where possible, questionable values were verified or corrected using other known information about the condenser. For example, the condenser specification sheet for Unit 3 indicates that the condenser's design steam inlet pressure is 1.18 inches HgA for the low-pressure zone and 1.65 inches HgA for the high-pressure zone. Other data note that the Unit 3 turbine, when operating at maximum load, will generally have exhaust backpressure values ranging from 2.5 to 2.8 inches HgA. The reason for the discrepancy is not clear, and insufficient information is available to determine how this would be affected by a conversion to a wet cooling tower system.

Likewise, backpressure values reported for Unit 1 at maximum load at different times of the year ranged from 2.0 to 2.6 inches HgA. Values in the higher end of the range were reported during months when the inlet water temperatures are typically at their lowest, with the lower values reported during warmer months. Again, the reasons why maximum load backpressures would be higher during colder months than they are during the summer are unclear, but may be correct if they are reflective of conditions that are unknown to this study.

In lieu of detailed operational data, calculations in this study are based on the system design specifications as provided by LADWP. Accordingly, the design backpressure value used for Unit 1 and Unit 2 is 1.5 inches HgA. For Unit 3, the design value is 1.65 inches HgA (for the high-pressure zone). Table O–5 summarizes the condenser design specifications for the three units.

Table O–5. Condenser Design Specifications

	Unit 1	Unit 2	Unit 3
Thermal load (MMBTU/hr)	695	695	1838.2
Surface area (ft^2)	95,100	95,100	237,000
Condenser flow rate (gpm)	78,000	78,000	188,000
Tube material	316 Stainless	316 Stainless	Cu-Ni (90-10)
Heat transfer coefficient (U_d)	340	340	459
Cleanliness factor	0.75	0.75	0.85
Inlet temperature (°F)	60	60	62
Temperature rise (°F)	17.83	17.83	19.51
Steam condensate temperature (°F)	91.7	91.7	94.8
Turbine exhaust pressure (in. HgA)	1.5	1.5	1.65 (hp zone)

3.2.2 AMBIENT ENVIRONMENTAL CONDITIONS

SGS is located in Los Angeles County along the shoreline of the Pacific Ocean approximately 1 mile south-southwest of the south runway at LAX. Cooling water is withdrawn from a submerged offshore location in the Pacific Ocean. Inlet temperature data specific to SGS were not available. Due to the proximity of El Segundo Generating Station (ESGS) and the substantially similar location of its respective intake structures (offshore in Santa Monica Bay), 2005 inlet temperature data provided by ESGS were used for SGS and serve as the basis for monthly once-through cooling water temperature values used in this study.

The wet bulb temperature used in the development of the overall cooling tower design was obtained from American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) publications. Data for Los Angeles at LAX indicate a 1 percent ambient wet bulb temperature of 69° F (ASHRAE 2006). An approach temperature of 12° F was selected based on the site configuration and vendor input. At the design wet bulb and approach temperatures, the cooling towers will yield “cold” water at a temperature of 81° F. Monthly maximum wet bulb temperatures used in the development of energy penalty estimates in Section 4.6 were calculated using data obtained from California Irrigation Management Information System (CIMIS) Monitoring Station 99 in Santa Monica (CIMIS 2006). Climate data used in this analysis are summarized in Table O–6.

Table O–6. Surface Water and Ambient Wet Bulb Temperatures

	Surface (°F)	Ambient wet bulb (°F)
January	59.2	54.3
February	60.3	56.1
March	61.5	57.7
April	63.1	60.7
May	66.0	65.7
June	68.0	68.3
July	71.4	69.3
August	72.2	69.4
September	67.0	65.5
October	63.5	60.3
November	62.0	56.3
December	60.7	55.5

3.2.3 LOCAL USE RESTRICTIONS

3.2.3.1 NOISE

Industrial development at SGS is regulated by the City of Los Angeles Municipal Code and the Westchester-Playa del Rey Community Plan. Both plans outline narrative criteria to be used as a guide for future development, but do not identify numeric noise limits for new construction. Based on consultation with the City of Los Angeles Department of Building and Safety, any measures limiting noise from a wet cooling tower would be addressed through a conditional use permit that evaluates the specific design of the project. Given the proximity of residential areas to the site (less than 800 feet to the east) and the proximity to Dockweiler State Beach (approximately 300 feet) this study used an ambient noise limit of 60 dBA at a distance of 800 feet in selecting the design elements of the wet tower installation. The wet cooling towers designed for SGS include low-noise fans and fan deck barrier walls to minimize noise associated with motor operation. Grade level sound barrier walls are not required.

3.2.3.2 BUILDING HEIGHT

SGS is located within the PF-1 zone, according to the planning and zoning code for Los Angeles. This zone is dedicated to heavy industry. Because it is located within the LAX Safety Corridor, the height of structures is generally limited to 150 feet above the 126-foot elevation contour. Most of the existing structures at SGS are located at an elevation of approximately 30 feet above sea level. East of the power blocks, the grade rises rapidly to a maximum elevation of approximately 155 feet above sea level (Figure O–3). The building code does not establish specific criteria for building height at other elevations within the PF-1 zone and instead relies on conditional use permitting that evaluates the specific design of the project. Given the existing height of the current structures at SGS and the proximity of residential and public recreational areas, this study selected a height restriction of 60 feet above grade level. The height of the wet cooling towers designed for SGS, from grade level to the top of the fan deck barrier wall, is 58 feet.

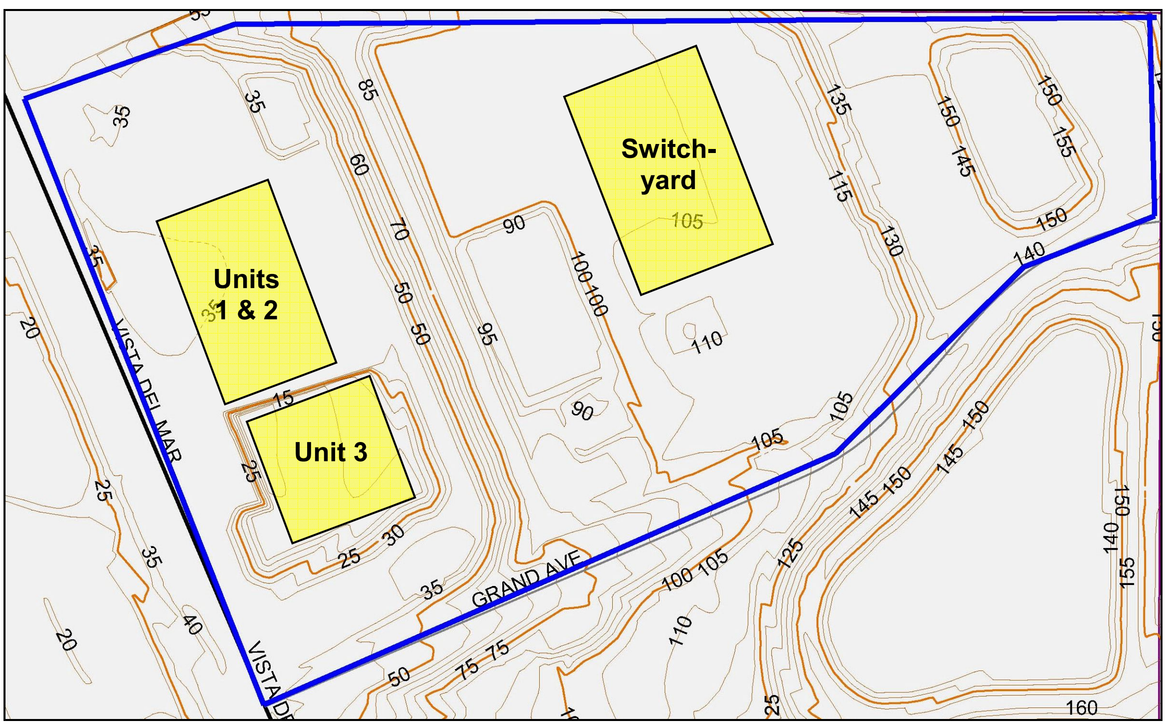

Figure O–3. Elevation Profile of SGS Site

3.2.3.3 PLUME ABATEMENT

Local zoning ordinances do not contain any specific criteria for addressing any impact associated with a wet cooling tower plume. Based on the proximity of SGS to LAX, however, plume abatement measures will likely be required. As shown in Figure O–1, SGS is located approximately 1 mile south-southwest of the airport. Further consideration must be made for the proximity of any eventual cooling tower to coastal recreational areas and the potential visual impact on those resources and nearby residential neighborhoods. California Energy Commission (CEC) siting guidelines and Coastal Act provisions evaluate the total size and persistence of a visual plume with respect to aesthetic standards for coastal resources; significant visual changes resulting from a persistent plume would likely be subject to additional controls.

Plume abatement towers were selected for evaluation at SGS due to the likelihood they would be required to eliminate potential impacts on operations at LAX. Section 3.2.3.5 details the available areas at SGS and placement of plume-abated towers.

3.2.3.4 DRIFT AND PARTICULATE EMISSIONS

Drift elimination measures that are considered best available control technology (BACT) are required for all cooling towers evaluated in this study regardless of their location. State-of-the-art drift eliminators are included for each cooling tower cell at SGS, with an accepted efficiency of 0.0005 percent. Because cooling tower PM_{10} emissions are a function of the rate of drift, drift eliminators are also considered BACT for PM_{10} emissions from wet cooling towers. This efficiency can be verified by a proper in situ test, which accounts for site-specific climate, water, and operating conditions. Testing based on the Isokinetic Drift Test Code published by the Cooling Tower Institute is only required at initial start-up on one representative cell of each tower, for an approximate cost of $60,000 per test, or approximately $240,000 for all four cooling towers at SGS (CTI 1994). This cost is not itemized in the final analysis and is instead included as part of the indirect cost estimate (Section 4.3).

3.2.3.5 FACILITY CONFIGURATION AND AREA CONSTRAINTS

The configuration of the SGS site, at only 56 acres spread across elevations ranging from 30 to 155 feet, creates several challenges in selecting a location for plume-abated cooling towers. As shown in Figure O–4, few areas are available that are large enough to accommodate wet cooling towers without the demolition and relocation of existing structures, and without also causing potential conflicts with other uses.

Area 1 is a small parcel located immediately to the north of Unit 1. The total area of this plot is approximately 30,000 square feet (200 feet by 150 feet). The entrance to SGS is located in this area, as is the lower end of the access road that leads to the upper areas of the property. The eastern edge of this area is currently occupied by a retention basin. Area 2 is a similarly sized parcel immediately south of Unit 3, with a total area of approximately 37,500 square feet (125 feet by 300 feet). This area is currently occupied by a retention basin and treatment tank.

Both areas are located very close to Vista del Mar and would require sufficient setback from the property line. Based on space requirements alone, it is feasible to locate the cooling tower for Unit 1 in Area 1 and the tower for Unit 2 in Area 2. Ultimately, however, these areas were not selected because the rapid rise in elevation to the east where the towers would be placed (rising from 30 to 85 feet) creates a barrier that may disrupt the necessary air flow through the plume-abated towers and negatively impact their performance.

Area 3 is 125,000 square foot parcel (250 feet by 500 feet) located immediately west of the switchyard at an elevation of approximately 100 feet. This area is sufficiently sized to accommodate the cooling towers for Unit 1 and Unit 2, but places them in a less-than-optimal configuration (roughly perpendicular to prevailing winds) and very close to the switchyard, where impacts from drift deposition on sensitive equipment and transmission lines may be significant. Two small cooling towers (used for bearing cooling water), as well as other small structures, are located in this area and would have to be removed or relocated to place cooling towers in this location. Sufficient capacity exists in the new cooling towers to compensate for the lost capacity of the small towers, although it is not known whether the equipment served by these towers would be adversely affected by switching from the current freshwater system to saltwater.

Area 4 is the largest contiguous parcel at SGS that is generally unoccupied, although small structures such as maintenance buildings would have to be relocated to allow placement here. The area, approximately 219,000 square feet (625 feet by 350 feet), is sufficient to accommodate the cooling tower for Unit 3, provided the tower is divided into two separate arrays. The configuration of this area enables towers to be placed in a generally longitudinal orientation with respect to the prevailing winds.

Area 5 is located at the easternmost portion of the facility and is occupied by three water storage tanks. Although this parcel is generally large enough to accommodate some of the necessary cooling towers, it was eliminated from consideration because its proximity to residential areas within the City of El Segundo would make it difficult, if not infeasible, to meet noise limitations in those areas.

Information from the Los Angeles County Assessor indicates that a parcel of land located south of Grand Avenue is currently owned by LADWP. This area is occupied by four decommissioned fuel oil storage tanks. Discussions with facility staff revealed that this area is slated for sale and cannot be used for any development related to SGS.

Based on the cooling tower design limitations discussed above, Area 3 and Area 4 were selected as the locations for the cooling towers. It is noted, however, that wet cooling towers placed in Area 3 will create a strong probability of interference with or damage to sensitive equipment in the switchyard resulting from salt drift deposition. Placement of wet cooling towers in this location will likely require relocation of the switchyard or replacement with gas insulated switchgear (GIS) to avoid these effects.

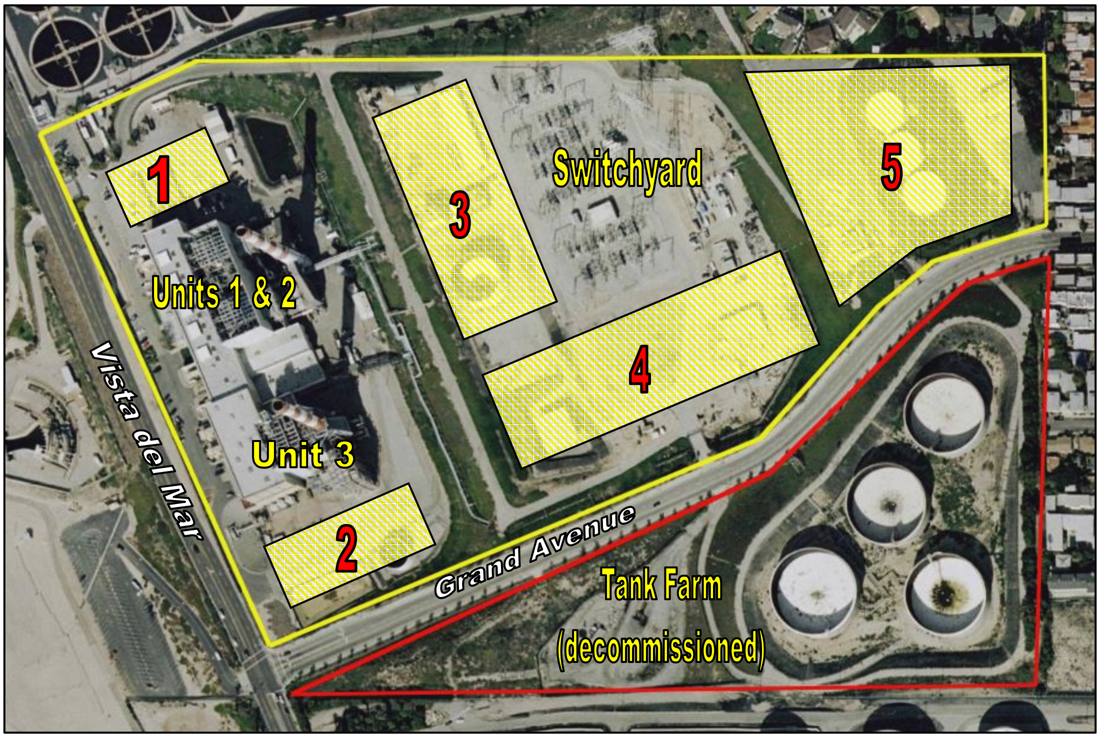

Figure O–4. Cooling Tower Siting Areas

3.3 CONCEPTUAL DESIGN

Based on the design constraints discussed above, four wet cooling towers were selected to replace the current once-through cooling system that currently serves Unit 1, Unit 2, and Unit 3 at SGS. Units 1 and 2 will each be served by an independently functioning tower, while Unit 3 will be served by two separate towers arranged in parallel. The Unit 3 towers will function independently (i.e., have separate pump houses and pumps) but will typically be used in conjunction with each other. Each tower at SGS consists of plume-abated cells configured in a multicell, inline arrangement.

3.3.1 SIZE

Each tower is constructed over a concrete collection basin 4 feet deep. The basin is larger than the footprint of the tower structure, extending an additional 2 feet in each direction. The concrete used for construction is suitable for saltwater applications. The principal tower material is fiberglass reinforced plastic (FRP), with stainless steel fittings. These materials are more resistant to the higher corrosive effects of saltwater.

The size of each tower is primarily based on the thermal load rejected to the tower by the surface condenser and a 12° F approach to the ambient wet bulb temperature. Flow rates through each condenser remain unchanged.

General characteristics of the wet cooling towers selected for SGS are summarized in Table O–7.

Table O–7. Wet Cooling Tower Design

	Tower 1 (Unit 1)	Tower 2 (Unit 2)	Tower Complex 3 (Unit 3)
Thermal load (MMBTU/hr)	695	695	1838
Circulating flow (gpm)	78,000	78,000	188,000
Number of cells	6	6	14
Plume free design point	50°F dry bulb 90% relative humidity	50°F dry bulb 90% relative humidity	50°F dry bulb 90% relative humidity
Tower type	Mechanical draft	Mechanical draft	Mechanical draft
Flow orientation	Counterflow	Counterflow	Counterflow
Fill type	Modular splash	Modular splash	Modular splash
Arrangement	Inline	Inline	Inline
Primary tower material	FRP	FRP	FRP
Tower dimensions (l x w x h) (ft) [1]	288 x 54 x 58	288 x 54 x 58	378 x 54 x 60
Tower footprint with basin (l x w) (ft) [1]	292 x 58	292 x 58	382 x 58

[1] For Unit 3, dimensions are applicable to each individual tower. Tower Complex 3 consists of two separate towers, each with these overall dimensions.

3.3.2 LOCATION

The initial site selection for each tower was based on the desire to locate each tower as close as possible to its respective generating unit to minimize the supply and return pipe distances and any increases in total pump head and brake horsepower. At SGS, the linear distance between the generating units is not significant (approximately 250 feet) and does not present any significant challenges with respect to supply and return pipelines. As noted above, the proximity of cooling towers to the switchyard is likely to cause drift deposition on sensitive equipment and transmission lines. Figure O–5 identifies the approximate location of each tower and supply and return piping.

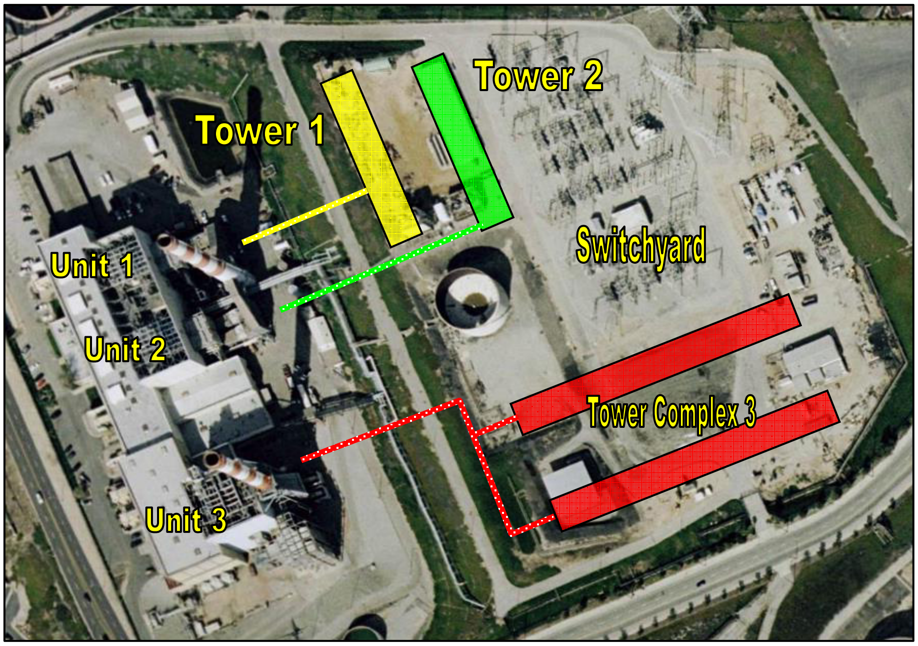

Figure O–5. Location of Cooling Towers

3.3.3 PIPING

The difference in elevation between the tower locations and the power block allows for the placement of most of the main supply and return pipelines above ground on pipe racks. All above-ground pipes are made of FRP. Short sections for the tower supply headers will be placed underground and made of prestressed concrete cylinder pipe (PCCP) suitable for saltwater applications. Pipelines connecting the condenser to the main supply and return lines are also placed above ground, which avoids the potential disruption that may be caused by excavation in and around the power block. The condensers at SGS are located at grade level, enabling a relatively straightforward connection.

Appendix B details the total quantity of each pipe size and type for SGS.

3.3.4 FANS AND PUMPS

Each tower cell uses an independent single-speed fan. The fan size and motor power are the same for each cell in all four towers at SGS.

This analysis includes new pumps to circulate water between the condensers and cooling towers. Pumps are sized according to the flow rate for each tower, the relative distance between the tower and condensers, and the total head required to deliver water to the top of the cooling tower riser. A separate, multilevel pump house is constructed for each cooling tower and is sized to accommodate the motor control centers (MCCs) and appropriate electrical switchgear. The electrical installation includes all necessary transformers, cabling, cable trays, lighting, and lightning protection. A 30-ton overhead crane is also included to allow for pump servicing.

Pumps serving the SGS cooling towers must overcome the difference in elevation between the power block and towers in addition to the elevation of the riser, for an approximate total of 110 feet.

Fan and pump characteristics associated with wet cooling towers at SGS are summarized in Table O–8. The net electrical demand of the fans and new pumps are discussed further as part of the energy penalty analysis in Section 4.6.

Table O–8. Cooling Tower Fans and Pumps

		Tower 1 (Unit 1)	Tower 2 (Unit 2)	Tower Complex 3 (Unit 3)
Fans	Number	6	6	14
	Type	Low noise Single speed	Low noise Single speed	Low noise Single speed
	Efficiency	0.95	0.95	0.95
	Motor power (hp)	211	211	211
Pumps	Number	2	2	4
	Type	50% recirculating Mixed flow Suspended bowl Vertical	50% recirculating Mixed flow Suspended bowl Vertical	50% recirculating Mixed flow Suspended bowl Vertical
	Efficiency	0.88	0.88	0.88
	Motor power (hp)	1,205	1,205	3,636

3.4 ENVIRONMENTAL EFFECTS

Conversion of the existing once-through cooling system at SGS to wet cooling towers will significantly reduce the intake of seawater from the Pacific Ocean and will presumably reduce impingement and entrainment by a similar proportion. Because closed-cycle systems will almost always result in condenser cooling water temperatures higher than those found in a comparable once-through system, wet towers will increase the operating heat rates at each of SGS's steam units, thereby decreasing the facility's overall efficiency. Additional power will also be consumed by the operation of tower fans and circulating pumps. Depending on how SGS chooses to address this change in efficiency, total stack emissions may increase for pollutants such as PM_{10}, SO_2, and NO_x, and may require additional control measures or the purchase of emission credits to meet air quality regulations. No control measures are currently available for CO_2 emissions, which will increase, on a per-kWh basis, by the same proportion as any change in the heat rate. The towers themselves will constitute an additional source of PM_{10} emissions, the annual mass of which will largely depend on the utilization capacity for the generating units served by the tower.

If SGS retains its National Pollutant Discharge Elimination System (NPDES) permit to discharge wastewater to the Pacific Ocean with a wet cooling tower system, it may have to address revised effluent limitations resulting from the substantial change in the quantity and characteristics of the discharge. Impacts from the discharge of elevated temperature wastes associated with the current once-through system, if any, will be minimized through the use of a wet cooling system.

3.4.1 AIR EMISSIONS

SGS is located in the South Central Coast air basin. Air emissions are permitted by the South Coast Air Quality Management District (SCAQMD) (Facility ID 800075).

Drift volumes are expected to be within the range of 0.5 gallons for every 100,000 gallons of circulating water in the towers. At SGS, this corresponds to a rate of approximately 1.75 gpm based on the maximum combined flow in the four towers. As discussed above, drift deposition has the potential to significantly impact the switchyard and transmission equipment.

Total PM_{10} emissions from the SGS cooling towers are a function of the number of hours in operation, overall water quality in the tower, and evaporation rate of drift droplets prior to deposition on the ground. Makeup water at SGS will be obtained from the same source currently used for once-through cooling water (Pacific Ocean). At 1.5 cycles of concentration and assuming an initial total dissolved solids (TDS) value of 35 parts per thousand (ppt), the water within the cooling towers will reach a maximum TDS level of roughly 53 ppt. Any drift droplets exiting the tower will have the same TDS concentration.

The cumulative mass emission of PM_{10} from SGS will increase as a result of the direct emissions from the cooling towers themselves. Stack emissions of PM_{10}, as well as SO_x, NO_x, and other pollutants, will increase due to the drop in fuel efficiency, although the cumulative increase will depend on actual operations and emission control technologies currently in use. Maximum drift and PM_{10} emissions from the cooling towers are summarized in Table O–9.[4]

2005 emission data for these pollutants is summarized in Table O–10 (CARB 2005). In 2005, SGS operated at an annual capacity utilization of 23.9 percent. Using this rate, the additional PM_{10} emissions from the cooling towers would increase the facility total by approximately 47 tons/year, or 106 percent.

Table O–9. Full Load Drift and Particulate Estimates

	PM10 (lbs/hr)	PM10 (tons/year)	Drift (gpm)	Drift (lbs/hr)
Tower 1	10	45	0.4	195
Tower 2	10	45	0.4	195
Tower Complex 3	25	108	0.9	472
Total SGS PM_{10} and drift emissions	**45**	**198**	**1.7**	**862**

Table O–10. 2005 Emissions of SO_x, NO_x, PM_{10}

Pollutant	Tons/year
NO_x	32.6
SO_x	43.2
PM_{10}	44.3

[4] This is a conservative estimate that assumes all dissolved solids present in drift droplets will be converted to PM_{10}. Studies suggest this may overestimate actual emission profiles for saltwater cooling towers (Chapter 4).

3.4.2 MAKEUP WATER

The volume of makeup water required by the four cooling towers at SGS is the sum of evaporative loss and the blowdown volume required to maintain the circulating water in the towers at the design TDS concentration. Drift expelled from the tower represents an insignificant volume by comparison and is accounted for by rounding up estimates of evaporative losses. Makeup water volumes are based on design conditions, and may fluctuate seasonally depending on climate conditions and facility operations. Use of wet cooling towers will reduce once-through cooling water withdrawals from the Pacific Ocean by approximately 95 percent over the current design intake capacity. Table O–11 summarizes the makeup water demand for SGS.

Table O–11. Makeup Water Demand

	Tower circulating flow (gpm)	Evaporation (gpm)	Blowdown (gpm)	Total makeup water (gpm)
Tower 1	78,000	1,200	2,400	3,600
Tower 2	78,000	1,200	2,400	3,600
Tower Complex 3	188,000	2,900	5,900	8,800
Total SGS makeup water demand	**344,000**	**5,300**	**10,700**	**16,000**

One circulating water pump, rated at 39,000 gpm, which is currently used to provide once-through cooling water to the facility, will be retained in a wet cooling system to provide makeup water to all four cooling towers. The capacity of the retained pump exceeds the makeup demand capacity by approximately 23,000 gpm. Any excess capacity will be routed through a bypass conduit and returned to the wet well at a point located behind the intake screens. Recirculating the excess capacity in this manner reduces additional costs that would be incurred if new pumps were required while maintaining the desired flow reduction. The intake of new water, measured at the intake screens, will be equal to the makeup water demand of the cooling towers. Figure O–6 presents a schematic of this configuration.

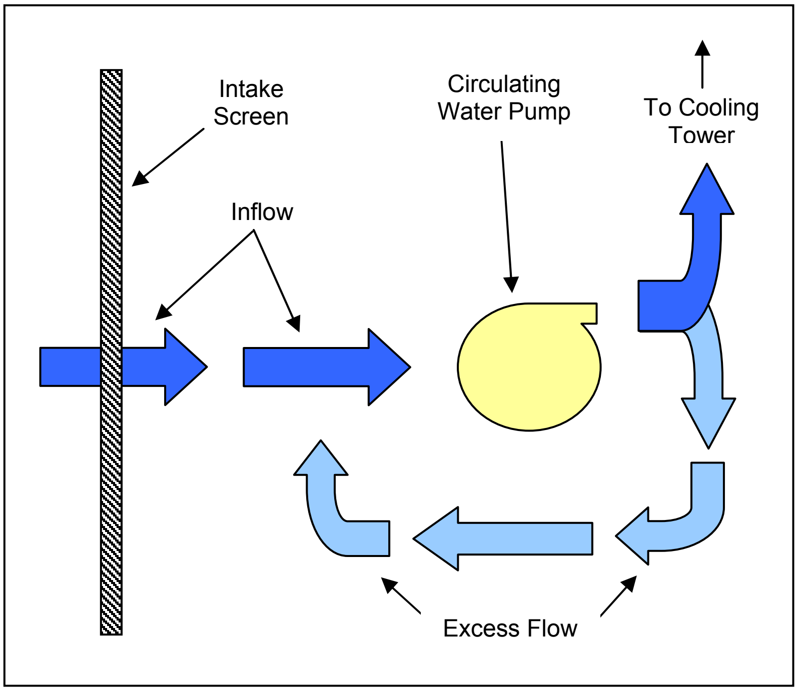

Figure O-6. Schematic of Intake Pump Configuration

The existing once-through cooling system at SGS does not treat water withdrawn from the Pacific Ocean, with the exception of screening for debris and larger organisms and periodic chlorination to control biofouling in the condenser tubes. Heat treatments are also periodically used to control mussel growth on pipes and condenser tubes by raising the temperature of the circulating water to 135º F. Conversion to a wet cooling tower system will not interfere with chlorination or heat treatment operations.

Makeup water will continue to be withdrawn from the Pacific Ocean.

The wet cooling tower system proposed for SGS includes water treatment for standard operational measures, i.e., fouling and corrosion control. Chemical treatment allowances are included in annual operations and maintenance (O&M) costs. It is assumed that the current once-through cooling water quality will be acceptable for use in a seawater cooling tower (with continued screening and chlorination) and will not require any pretreatment to enable its use.

3.4.3 NPDES PERMIT COMPLIANCE

At maximum operation, wet cooling towers at SGS will result in an effluent discharge of approximately 15 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, floor drain wastes, and cleaning wastes. These low-volume wastes may add an additional 0.25 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, SGS will be required to modify its existing individual wastewater discharge (NPDES) permit. Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0000370, as implemented by LARWQCB Order 00-083. All wastewaters are discharged to the Pacific Ocean through a submerged conduit extending approximately 1,200 feet offshore. The existing order contains effluent limitations based on the 1997 Ocean Plan and 1972 Thermal Plan.

SGS will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities (40 CFR 423.13(d)(1)). These ELGs set numeric limitations for chromium and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity). Because ELGs are technology-based limitations, mixing zones or dilution factors are not applicable when determining compliance; limits must be met at the point of discharge from the cooling tower prior to commingling with any other waste stream. ELGs for cooling tower blowdown target priority pollutants that are contributed by maintenance chemicals and do not apply when limits may be exceeded as a result of background concentrations or other sources. Further discussion can be found in Chapter 4, Section 3.6.

Conversion to wet cooling towers will alter the volume and composition of a facility's wastewater discharge because wet towers concentrate certain pollutants in the effluent waste stream. The cooling towers designed for SGS operate at 1.5 cycles of concentration, i.e., the blowdown discharge will contain a dissolved solids concentration 50 percent higher than the makeup water.

Changes to discharge composition may affect compliance with water quality objectives included in the Ocean Plan. If compliance with these objectives becomes problematic, alternative treatment or discharge methods may be necessary. Compliance may be achieved by altering the discharge configuration in such a way as to increase dilution (e.g., diffuser ports), or by seeking a mixing zone and dilution credits as permissible under the Ocean Plan. Alternately, some low volume waste streams (e.g., boiler blowdown, laboratory drains) may be diverted, with necessary permits, for treatment at a POTW.

If more pollutant-specific treatment methods, such as filtration or precipitation technologies, become necessary to meet WQBELs, the initial capital cost may range from $2 to $5.50 per 1,000 gallons of treatment capacity, with annual costs of approximately $0.5 per gallon of capacity, depending on the method of treatment (FRTR 2002). Hazardous material disposal fees and permits would further increase costs.

This evaluation did not include alternative discharge or effluent treatment measures in the conceptual design because the variables used to determine final WQBELs, which would be used to determine the type and scope of the desired compliance method, cannot be quantified here. Likewise, the final cost evaluation (Section 4.0) does not include any allowance for these possibilities.

Thermal discharge standards are based on narrative criteria established for coastal discharges under the Thermal Plan, which requires that existing discharges of elevated-temperature wastes comply with effluent limitations necessary to assure the protection of designated beneficial uses. The LARWQCB has implemented this provision by establishing a maximum discharge temperature of 100º F during normal operations in Order 00-083 (LARWQCB 2000). Information available for review indicates SGS has consistently been able to comply with this requirement. Because cooling tower blowdown will be taken from the "cold" side of the tower, conversion to a wet cooling system will significantly reduce the discharge temperature (to less than 81º F) and the size of any related thermal plume in the receiving water.

3.4.4 RECLAIMED WATER

The use of reclaimed or alternative water sources could potentially eliminate all surface water withdrawals at SGS. Doing so would completely eliminate impingement and entrainment concerns, and might enable the facility to avoid possible effluent quality and permit compliance issues, depending on the quality of reclaimed water available for use. In addition, wet cooling towers using reclaimed water would be expected to have lower PM_{10} emissions due to the lower TDS levels. The California State Water Resources Control Board (SWRCB), in 1975, issued a policy statement requiring the consideration of alternative cooling methods in new power plants, including the use of reclaimed water, over the use of freshwater (SWRCB 1975). There is no similar policy regarding the use of marine waters, but the clear preference of state agencies is to encourage alternative cooling methods, including the use of reclaimed water, wherever possible.

The present volume of available secondary treated water within a 15-mile radius of SGS (680 mgd) can meet the current once-through cooling demand for all three generating units (495 mgd), although the volume that is reliably available would require pipeline connections to two different sources to ensure an adequate and consistent flow. In lieu of secondary treated water as a replacement for once-through cooling, reclaimed water can be used as makeup water in cooling towers but must meet tertiary treatment and disinfection standards under California Code of Regulations (CCR) Title 22.

If the reclaimed water is not treated to the required levels, SGS would be required to provide sufficient treatment prior to use in the cooling towers. Currently, the West Basin Municipal Water District (WBMWD) treats approximately 30 mgd of secondary water from Hyperion WWTP to tertiary standards. This water is used for various projects throughout the South Bay region, such as the seawater barrier conservation project to protect underground aquifers. WBMWD's current available capacity is insufficient to meet the makeup water demand for the wet cooling towers at SGS (WBMWD 2007). Limited space at SGS will likely make any onsite treatment system problematic, depending on the system's size and configuration.

An additional consideration for the use of reclaimed water is the presence of any ammonia or ammonia-forming compounds in the reclaimed water. The condenser tubes for Unit 3 contain copper alloys (90-10 Cu-Ni) and can experience stress-corrosion cracking as a result of the interaction between copper and ammonia. Treatment for ammonia may include the addition of ferrous sulfate as a corrosion inhibitor or require ammonia-stripping towers to pretreat reclaimed water prior to use in the cooling towers (EPA 2001). The condenser tubes for Unit 1 and Unit 2 are made of 316 stainless steel.

Two publicly owned treatment works (POTWs) were identified within a 15-mile radius of SGS, with a combined discharge capacity of 680 mgd. Figure O–7 shows the relative locations of these facilities to SGS.

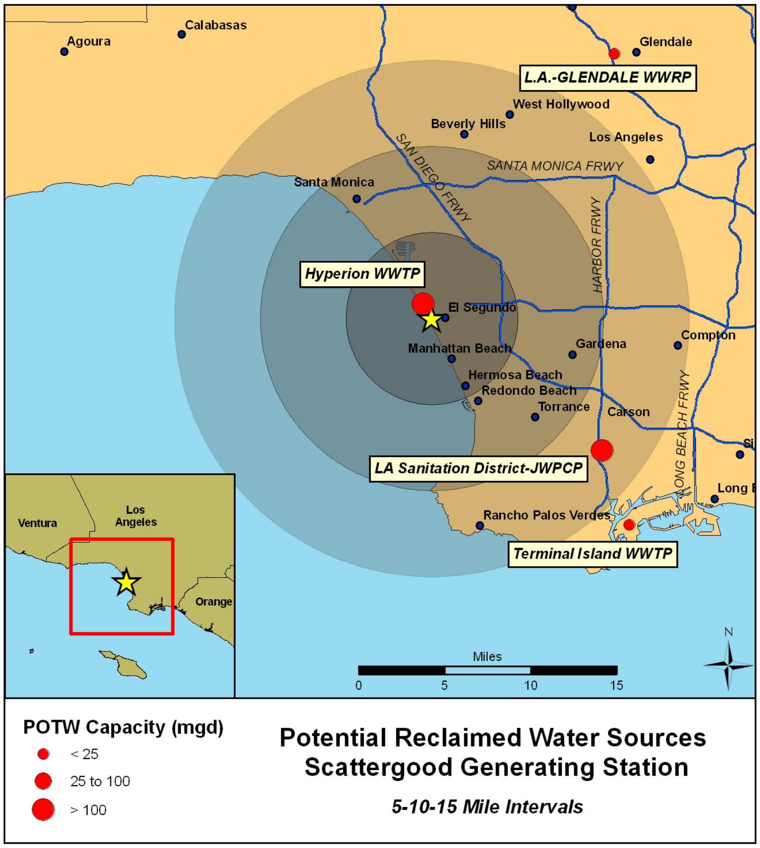

Figure O–7. Reclaimed Water Sources

- *Los Angeles Sanitation District, Hyperion Wastewater Treatment Plant—Los Angeles*
  Discharge volume: 350 mgd
  Distance: Adjacent to north end of SGS
  Treatment level: Secondary

  The CEC evaluated the use of secondary treated water from Hyperion as a replacement for once-through cooling in the Final Staff Assessment (FSA) to the El Segundo Power Replacement (ESPR) project in 2002. While the FSA did not directly consider use of Hyperion water at SGS, the conclusions in that study are generally applicable to SGS, given the similarities between the two facilities in terms of makeup demand and existing configuration.

  The assessment determined that the use of Hyperion's water was technically feasible (as a once-through replacement), although the evaluation was based on a once-through demand of 207 mgd that would have been required for the ESPR. Because the distance offshore (2,100 feet) of the ESGS outfall is insufficient to meet water quality standards for public beaches, secondary water used at ESGS would either be returned to Hyperion for discharge through the Hyperion "5 mile" outfall, treated prior to discharge, or used for another purpose (CEC 2002a).

Any water used in a wet cooling tower at SGS would have to be treated onsite at the facility to meet tertiary treatment standards. Hyperion currently provides only secondary treatment and does not appear to have sufficient area on which to construct a tertiary treatment system. WBMWD does not have sufficient excess capacity to meet the demand of freshwater towers at SGS (10 to 12 mgd). The 2002 FSA deemed tertiary treatment at ESGS infeasible due to the overall size of the treatment facility and the lack of sufficient space at the site (CEC 2002a). The final commission decision, however, found that this option was infeasible (CEC 2005). It is unclear if sufficient area is available at SGS to accommodate a treatment facility in addition to the wet cooling towers.

- *Los Angeles Sanitation District, Joint Water Pollution Control Plant (JWPCP)—Carson*
  Discharge volume: 330 mgd
  Distance: 13 miles southeast
  Treatment level: Secondary

  The facility representative at JWPCP indicated that the effluent is not currently considered a potential source of reclaimed water for irrigation due to high TDS concentrations (brine from the Hyperion WWTP is treated at Carson), but the suitability for use as a makeup water source is not currently known. TDS levels may be less than normally found in seawater and thus be at least comparable to the current makeup water source at SGS. In the future, a portion of the effluent may be used for a new hydrogen plant under consideration by BP (formerly British Petroleum), but no formal agreement currently exists. Even with such an agreement, sufficient capacity would remain to satisfy the full makeup water demand for freshwater towers at SGS (10 to 12 mgd).

The costs associated with installing transmission pipelines (excavation/drilling, material, labor), in addition to design and permitting costs, are difficult to quantify in the absence of a detailed analysis of various site-specific parameters that will influence the final configuration. The nearest facility with sufficient capacity to satisfy SGS's makeup demand (10 to 12 mgd for freshwater towers) is located adjacent to the SGS property (Hyperion). Based on data compiled for this study and others, the estimated installed cost of a 24-inch prestressed concrete cylinder pipe, sufficient to provide 12 mgd to SGS, is $300 per linear foot, or approximately $1.6 million per mile. Additional considerations, such as pump capacity and any required treatment, would increase the total cost.

Regulatory concerns beyond the scope of this investigation may make the use of reclaimed water comparable or preferable to the use of saltwater from marine sources as makeup water. Use of freshwater may reduce or eliminate drift deposition impacts on sensitive equipment. Reclaimed water may enable SGS to reduce PM_{10} emissions from the cooling tower, which is a concern given the current nonattainment status of the South Coast air basin, or eliminate potential conflicts with water discharge limitations. SGS might realize other benefits by using reclaimed water in the form of reduced O&M costs.

At any facility where wet cooling towers are a feasible alternative, reclaimed water may be used as a makeup water source; the practicality of its use, however, is a question of the overall cost, availability, and additional environmental benefit that may be realized.

3.4.5 THERMAL EFFICIENCY

The use of wet cooling towers at SGS will increase the temperature of the condenser inlet water by a range of 9 to 13° F above the surface water temperature, depending on the ambient wet bulb temperature at the time. The generating units at SGS are designed to operate at the conditions described in Table O–12. The resulting monthly difference between once-through and wet cooling tower condenser inlet temperatures at SGS is described in Figure O–8.

Table O–12. Design Thermal Conditions

	Unit 1	Unit 2	Unit 3
Design backpressure (in. HgA)	1.5	1.5	1.65
Design water temperature (°F)	60	60	62
Turbine inlet temp (°F)	1,000	1,000	1,000
Turbine inlet pressure (psia)	1,850	1,850	3,500
Full load heat rate (BTU/kWh) [1]	9,459	9,564	9,276

[1] CEC 2002b.

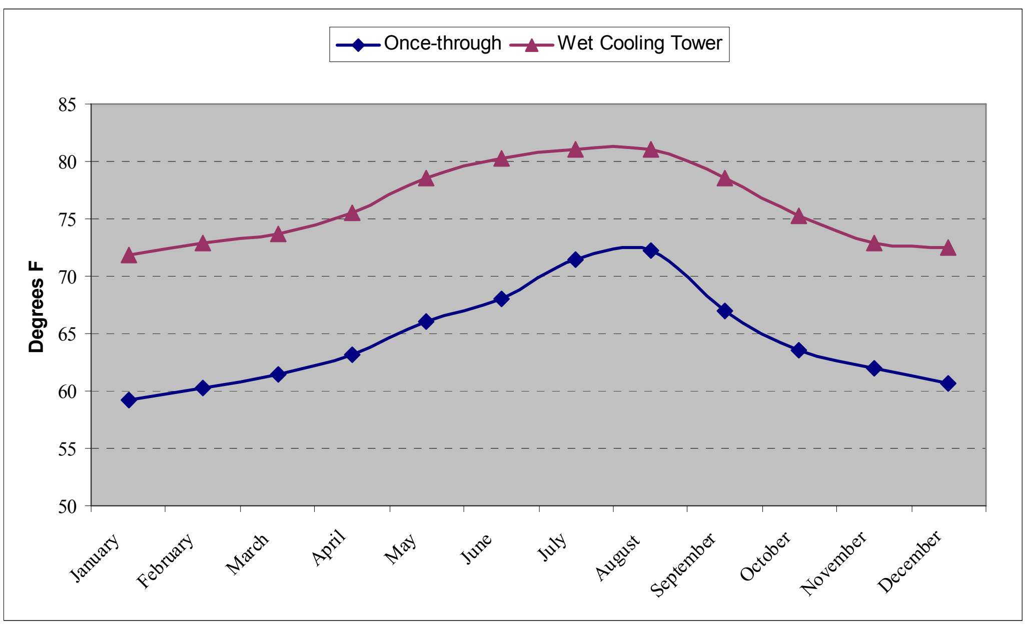

Figure O–8. Condenser Inlet Temperatures

Backpressures for the once-through and wet cooling tower configurations were calculated using the design criteria described in the sections above on a monthly basis using ambient climate data.

In general, backpressures associated with the wet cooling tower were elevated by 0.5 to 0.8 inches HgA compared with the current once-through system (Figure O–9, Figure O–11, and Figure O–13).

Heat rate adjustments were calculated by comparing the theoretical change in available energy that occurs at different turbine exhaust backpressures, assuming the thermal load and turbine inlet pressure remain constant, i.e., at the maximum load rating. The relative change at different backpressures was compared with the value calculated for the design conditions (i.e., at design turbine inlet and exhaust backpressures) and plotted as a percentage of the maximum operating heat rate to develop estimated correction curves (Figure O–10, Figure O–12, and Figure O–14). A comparison was then made between the relative heat rates of the once-through and wet cooling systems for a given month. The difference between these two values represents the net increase in heat rate that would be expected in a converted system.

Table O–13 summarizes the annual average heat rate increase for each unit as well as the increase associated with the peak demand period of July-August-September. Monthly values were used to develop an estimate of the monetized value of these heat rate changes (Section 4.6.2). Month-by-month calculations are presented in Appendix A.

Table O–13. Summary of Estimated Heat Rate Increases

	Unit 1	Unit 2	Unit 3
Peak (July-August-September)	1.28%	1.28%	1.35%
Annual average	1.27%	1.27%	1.19%

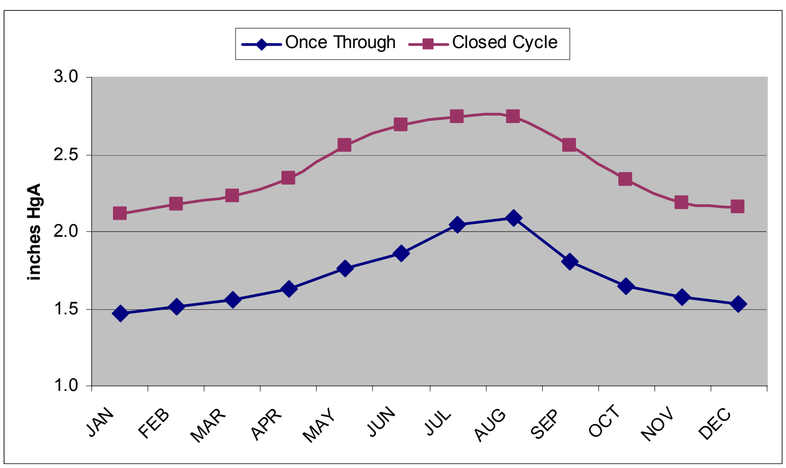

Figure O–9. Estimated Backpressures (Unit 1)

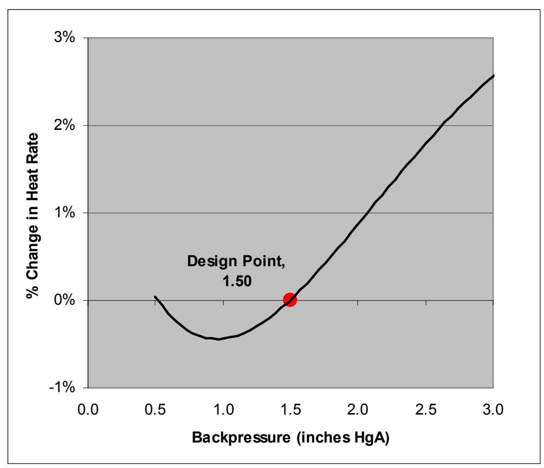

Figure O–10. Estimated Heat Rate Correction (Unit 1)

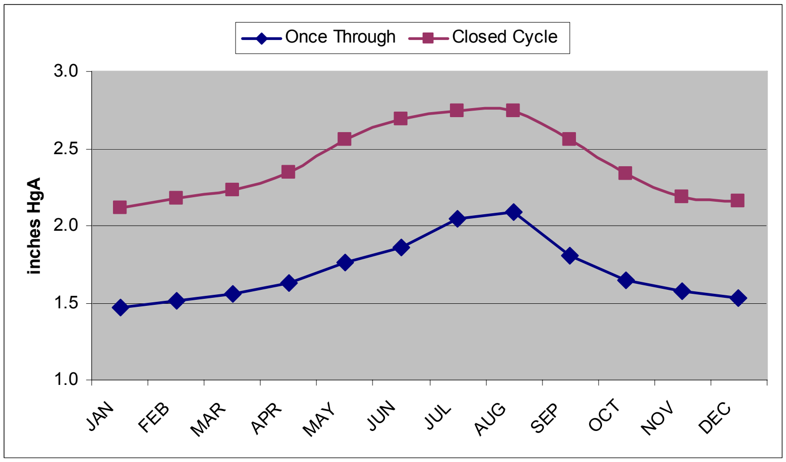

Figure O–11. Estimated Backpressures (Unit 2)

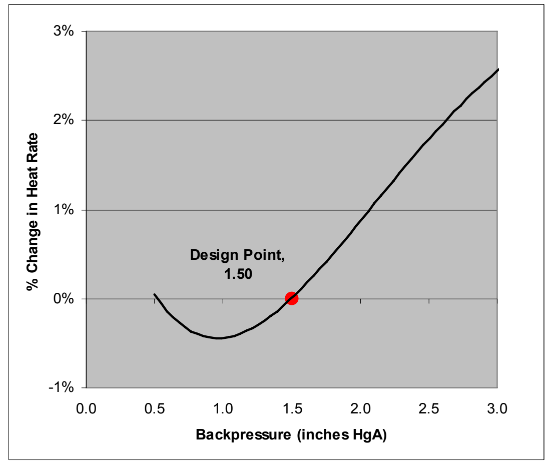

Figure O–12. Estimated Heat Rate Correction (Unit 2)

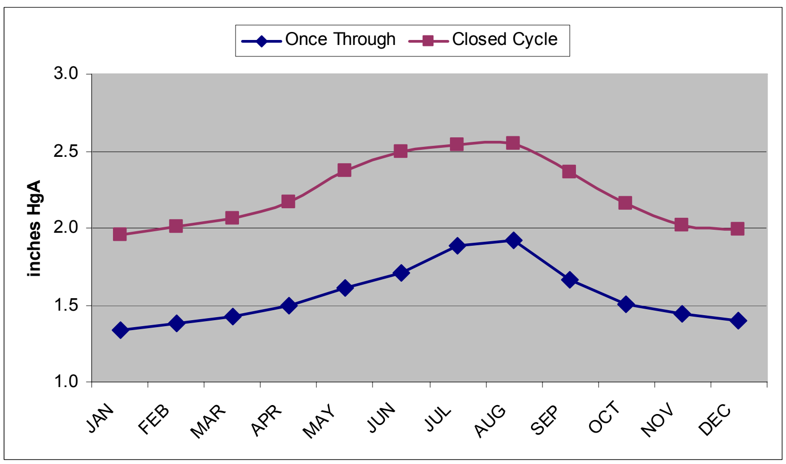

Figure O–13. Estimated Backpressures (Unit 3)

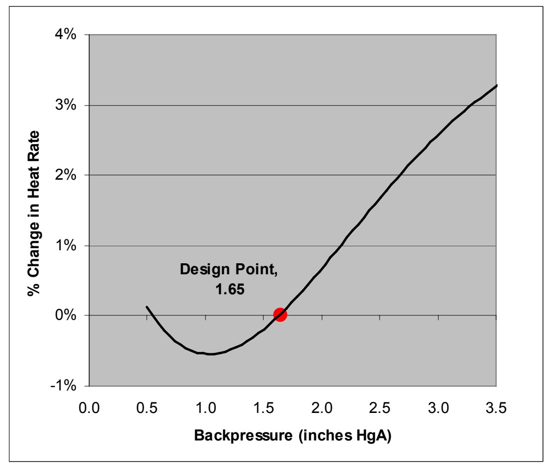

Figure O–14. Estimated Heat Rate Correction (Unit 3)

4.0 RETROFIT COST ANALYSIS

The wet cooling system retrofit estimate for SGS is based on incorporating plume-abated wet cooling towers as a replacement for the existing once-through system that serves the three generating units. Standard cost elements for this project include the following:

- Direct (cooling tower installation, civil/structural, mechanical, piping, electrical, and demolition)
- Indirect (smaller project costs not itemized)
- Contingency (allowance for unknown project variables)
- Operations and maintenance (nonenergy-related cooling tower operations)
- Energy penalty (includes increased parasitic use from fans and pumps as well as decreased thermal efficiency)
- Revenue loss from shutdown (net loss in revenue during construction phase)

The cost analysis does not include allowances for elements that are not quantified in this study, such as land acquisition, effluent treatment, or air emission reduction credits. The methodology used to develop cost estimates is discussed in Chapter 5.

4.1 COOLING TOWER INSTALLATION

The requirement to use plume-abated towers at SGS increases the per-cell cost by a factor of approximately 2.7 over the cost of conventional tower cells (compared with the cost of cells designed for ESGS). Table O–14 summarizes the design-and-build cost estimate for each tower developed by vendors, inclusive of all labor and management required for their installation.

Table O–14. Wet Cooling Tower Design-and-Build Cost Estimate

	Unit 1	Unit 2	Unit 3	SGS total
Number of cells	6	6	14	**26**
Cost/cell ($)	1,633,333	1,633,333	1,821,429	**1,734,615**
Total SGS D&B cost ($)	**9,800,000**	**9,800,000**	**25,500,000**	**45,100,000**

4.2 OTHER DIRECT COSTS

A significant portion of the cost incurred for the wet cooling tower installation results from the various support structures and materials (pipes, pumps, etc.), as well the necessary equipment and labor required to prepare the cooling tower site and connect the towers to the cooling system. At SGS, these costs comprise approximately 45 percent of the initial capital cost. Line item costs are detailed in Appendix B.

Deviations from or additions to the general cost elements discussed in Chapter 5 are discussed below. Other direct costs (non–cooling tower) are summarized in Table O–15.

Table O–15. Summary of Other Direct Costs

	Equipment ($)	Bulk material ($)	Labor ($)	SGS total ($)
Civil/structural/piping	4,800,000	17,800,000	14,400,000	37,000,000
Mechanical	9,000,000	0	500,000	9,500,000
Electrical	1,600,000	3,100,000	2,000,000	6,700,000
Demolition	0	0	400,000	400,000
Total SGS other direct costs	**15,400,000**	**20,900,000**	**17,300,000**	**53,600,000**

- *Civil, Structural, and Piping*
  The configuration of the SGS site allows each tower to be located within relative proximity to its respective generating unit. Most pipes are above ground and made of FRP.
- *Mechanical and Electrical*
  Initial capital costs in this category reflect incorporating new pumps (eight total) to circulate cooling water between the towers and condensers. No new pumps are required to provide makeup water from the Pacific Ocean. Electrical costs are based on the battery limit after the main feeder breakers. Because the cooling towers are located at an elevation approximately 70 feet above the condensers, larger-capacity pumps are required to circulate water from the condenser to the top of the riser.
- *Demolition*
  Costs for the demolition of the existing cooling towers and other small structures are included for SGS.

4.3 INDIRECT AND CONTINGENCY

Indirect costs are calculated as 25 percent of all direct costs (civil/structural, mechanical, electrical, demolition, and cooling towers). An additional allowance is included for reinforcement of the condenser to withstand the increased pressures resulting from incorporation of wet cooling towers. Each condenser may require reinforcement of the tube sheet bracing with 6-inch by 1inch steel, and water box reinforcement/replacement with 5/8-inch carbon steel. Based on the data outlined in Chapter 5, a conservative estimate of 5 percent of all direct costs is included to account for possible condenser modifications.

The contingency cost is calculated as 25 percent of the sum of all direct and indirect costs, including condenser reinforcement. At SGS, potential costs in this category include relocation or demolition of small buildings and structures and the potential interference with underground structures. Modifications or upgrades to sensitive equipment may be necessary to counteract drift deposition. Soils were not characterized for this analysis. SGS is situated at 30 feet above sea level adjacent to the Pacific Ocean. Seawater intrusion or the instability of sandy soils may require additional pilings to support any large structures built at the site. Initial capital costs are summarized in Table O–16.

Table O–16. Summary of Initial Capital Costs

	Cost ($)
Cooling towers	45,100,000
Civil/structural/piping	37,000,000
Mechanical	9,500,000
Electrical	6,700,000
Demolition	400,000
Indirect cost	24,700,000
Condenser modification	4,900,000
Contingency	32,100,000
Total SGS capital cost	**160,400,000**

4.4 SHUTDOWN

A portion of the work relating to installing wet cooling towers can be completed without significant disruption to the operations of SGS. Units will be offline depending on the length of time it takes to integrate the new cooling system and conduct acceptance testing. For SGS, a conservative estimate of 4 weeks per unit was developed. Based on 2005 generating output, however, no shutdown is forecast for any of the three units. Therefore, the cost analysis for SGS does not include any loss of revenue associated with shutdown at SGS.

This analysis did not consider shutdown with respect to the required availability of a particular generating unit, nor can it automatically be assumed that the generating profile for 2006 will be the same in each subsequent year. Net output data from 2006 may not reflect any contractual obligations that mandate a particular unit's availability during a given time period.

4.5 OPERATIONS AND MAINTENANCE

O&M costs for a wet cooling tower system at SGS include routine maintenance activities; chemicals and treatment systems to control fouling and corrosion in the towers; management and labor; and an allowance for spare parts and replacement. Annual costs are calculated based on the circulating water flow capacity of the towers using a base cost of $4.00/gpm in Year 1 and $5.80/gpm in Year 12, with an annual escalator of 2 percent (USEPA 2001). Year 12 costs increase based on the assumption that maintenance needs, particularly for spare parts and replacements, will be greater for years 12–20. Annual O&M costs, based on the design circulating water flow for the four cooling towers at SGS (344,000 gpm), are presented in Table O–17. These costs reflect maximum operation.

Table O–17. Annual O&M Costs (Full Load)

	Year 1 ($)	Year 12 ($)
Management/labor	344,000	499,525
Service/parts	551,200	799,240
Fouling	482,300	699,335
Total SGS O&M cost	**1,377,500**	**1,998,100**

4.6 ENERGY PENALTY

The energy penalty is divided into two components: increased parasitic use resulting from the additional electrical demand of cooling tower fans and pumps; and the decrease in thermal efficiency resulting from elevated turbine backpressure values. Monetizing the energy penalty at SGS requires some assumption as to how the facility will choose to alter its operations to compensate for these changes, if at all. One option would be to accept the reduced amount of revenue-generating electricity available and absorb the economic loss ("production loss option"). A second option would be to increase the firing rate to the turbine (i.e., consume more fuel) and produce the same amount of revenue-generating electricity as had been obtained with the once-through cooling system ("increased fuel option"). A more likely option, however, is some combination of the two.

Ultimately, the manner in which SGS would alter operations to address efficiency changes is driven by considerations unknown to this study (e.g., corporate strategy, contractual obligations, operating protocols and turbine pressure tolerances). In all summary cost estimates, this study calculates the energy penalty's monetized value by assuming the facility will use the increased fuel option to compensate for reduced efficiency and generate the amount of electricity equivalent to the estimated shortfall. With this option, the energy penalty is equivalent to the financial cost of additional fuel and is nominally less costly than the production loss option. This option, however, may not reflect long-term costs such as increased maintenance or system degradation that may result from continued operation at a higher-than-designed turbine firing rate.[5]

The energy penalty for SGS is calculated by first estimating the increased parasitic demand from the cooling tower pumps and fans, expressed as a percentage of each unit's or unit pair's rated capacity. Likewise, the change in the unit's heat rate is also expressed as a capacity percentage.

4.6.1 INCREASED PARASITIC USE (FANS AND PUMPS)

Depending on ambient conditions or the operating load at a given time, SGS may be able to take one or more cooling tower cells offline and still obtain the required level of cooling. This would also reduce the cumulative electrical demand from the fans. For the purposes of this study,

[5] Increasing the thermal load to the turbine will raise the circulating water temperature exiting the condenser. The cooling towers selected for this study are designed with a maximum water return temperature of approximately 120º F. Depending on each unit's operating conditions (i.e., condenser outlet temperature), the degree to which the thermal input to the turbine can be increased may be limited.

however, operations are evaluated at the design conditions, i.e., maximum load; no allowance is made for seasonal changes. The increased electrical demand associated with operation of the cooling tower fans is summarized in Table O–18.

Table O–18. Cooling Tower Fan Parasitic Use

	Tower 1	Tower 2	Tower Complex 3	SGS total
Units served	Unit 1	Unit 2	Unit 3	--
Generating capacity (MW)	179	179	445	**803**
Number of fans (one per cell)	6	6	14	**26**
Motor power per fan (hp)	211	211	211	--
Total motor power (hp)	1,263	1,263	2,947	**5,473**
MW total	0.94	0.94	2.20	**4.08**
Fan parasitic use (% of capacity)	**0.53%**	**0.53%**	**0.49%**	**0.51%**

The addition of new circulating water pump capacity for the wet cooling towers will also increase the parasitic use of electricity at SGS. Makeup water will continue to be withdrawn from the Pacific Ocean through the use of one of the existing circulating water pumps; the remaining pumps will be retired. The net increase in pump-related parasitic usage is the difference between the new wet cooling tower configuration (new plus retained pumps) and the existing once-through configuration. Because one of the main design assumptions maintains the existing flow rate through each condenser, the new circulating pumps are single speed and are assumed to operate at their full rated capacity when in use. The increased electrical demand associated with operation of the cooling tower pumps is summarized in Table O–19.

Table O–19. Cooling Tower Pump Parasitic Use

	Tower 1	Tower 2	Tower Complex 3	SGS total
Units served	Unit 1	Unit 2	Unit 3	--
Generating capacity (MW)	179	179	445	**803**
Existing pump configuration (hp)	680	680	3,000	**4,360**
New pump configuration (hp)	2,609	2,609	14,945	**20,164**
Difference (hp)	1,929	1,929	11,945	**15,804**
Difference (MW)	1.4	1.4	8.9	**11.8**
Net pump parasitic use (% of capacity)	**0.80%**	**0.80%**	**2.00%**	**1.47%**

4.6.2 HEAT RATE CHANGE

Adjustments to the heat rate were calculated based on the ambient conditions for each month and reflect the estimated difference between operations with once-through and wet cooling tower systems. As noted above, the energy penalty analysis assumes SGS will increase its fuel consumption to compensate for lost efficiency as well as the increased parasitic load from fans and pumps. The higher turbine firing rate will increase the thermal load rejected to the condenser, which, in turn, results in a higher backpressure value and corresponding increase in the heat rate. No data are available describing the changes in turbine backpressures above the design thermal loads. For the purposes of monetizing the energy penalty only, this study conservatively assumed an additional increase in the heat rate of 0.5 percent at the higher firing rate; the actual effect at AGS may be greater or less. Changes in the heat rate for each unit at SGS are presented in Figure O–15 through Figure O–17.

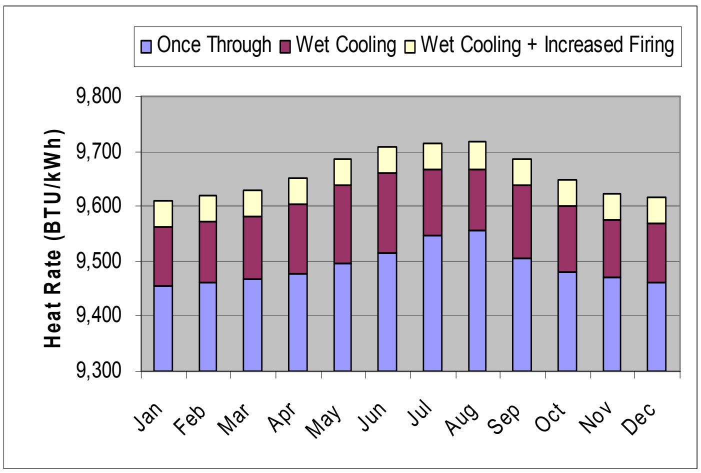

Figure O–15. Estimated Heat Rate Change (Unit 1)

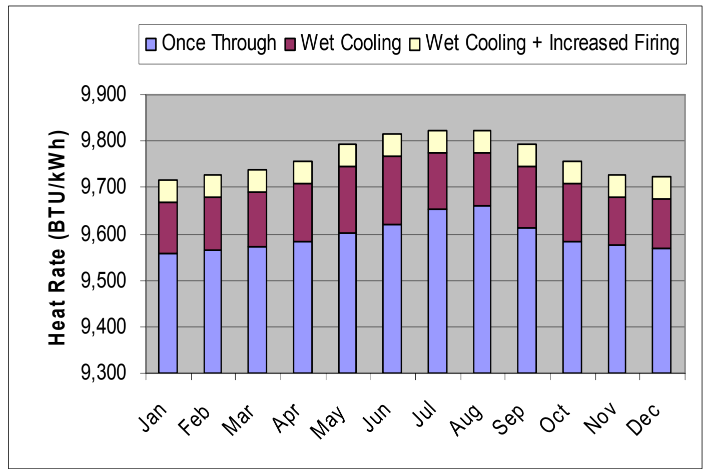

Figure O–16. Estimated Heat Rate Change (Unit 2)

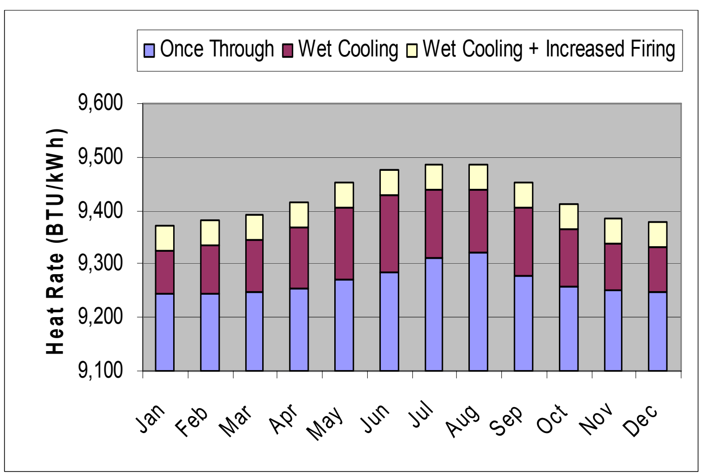

Figure O–17. Estimated Heat Rate Change (Unit 3)

4.6.3 CUMULATIVE ESTIMATE

Using the increased fuel option, the cumulative value of the energy penalty is obtained by first calculating the relative costs of generation ($/MWh) for the once-through and overfired wet cooling systems. The cost of generation for SGS is based on the relative heat rates developed in Section 4.6.2 and the average monthly wholesale natural gas cost ($/MMBTU) (ICE 2006a). The difference between these two values represents the increased cost, per MWh, that results from incorporating wet cooling towers. The net difference in cost, per month, is applied to the net MWh generated for the particular month, and summed to determine an annual estimate. Based on 2005 output data, the annual energy penalty for SGS will be approximately $1.5 million. Table O–20 though Table O–22 summarize the energy penalty estimates for each unit.

Table O–20. Unit 1 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2005 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	9,454	56.72	9,609	57.66	0.93	43,793	**40,772**
February	5.50	9,460	52.03	9,620	52.91	0.88	2,675	**2,361**
March	4.75	9,466	44.97	9,630	45.74	0.78	726	**565**
April	4.75	9,477	45.01	9,651	45.84	0.83	0	**0**
May	4.75	9,497	45.11	9,687	46.01	0.90	0	**0**
June	5.00	9,514	47.57	9,708	48.54	0.97	27,209	**26,367**
July	6.50	9,548	62.06	9,716	63.15	1.09	10,083	**11,022**
August	6.50	9,556	62.11	9,716	63.16	1.04	12,240	**12,778**
September	4.75	9,506	45.15	9,686	46.01	0.86	0	**0**
October	5.00	9,479	47.39	9,648	48.24	0.85	26,023	**22,028**
November	6.00	9,469	56.82	9,622	57.73	0.91	72,208	**65,994**
December	6.50	9,462	61.50	9,617	62.51	1.01	23,786	**23,929**
							Unit 1 total	**205,816**

Table O–21. Unit 2 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2005 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	9,559	57.35	9,716	58.30	0.94	55,471	**52,196**
February	5.50	9,565	52.61	9,727	53.50	0.89	58,955	**52,588**
March	4.75	9,571	45.46	9,737	46.25	0.79	59,964	**47,134**
April	4.75	9,582	45.51	9,758	46.35	0.84	60,751	**50,743**
May	4.75	9,603	45.61	9,795	46.53	0.91	68,799	**62,732**
June	5.00	9,620	48.10	9,816	49.08	0.98	70,651	**69,182**
July	6.50	9,653	62.75	9,823	63.85	1.10	63,113	**69,707**
August	6.50	9,662	62.80	9,824	63.86	1.05	67,671	**71,383**
September	4.75	9,611	45.65	9,794	46.52	0.87	60,432	**52,410**
October	5.00	9,584	47.92	9,755	48.78	0.86	42,084	**36,002**
November	6.00	9,574	57.45	9,728	58.37	0.92	0	**0**
December	6.50	9,567	62.19	9,723	63.20	1.02	36,084	**36,688**
							Unit 2 total	**600,765**

Table O–22. Unit 3 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2005 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	9,243	55.46	9,372	56.23	0.78	5,606	**4,363**
February	5.50	9,246	50.85	9,383	51.61	0.76	0	**0**
March	4.75	9,249	43.93	9,393	44.62	0.68	9,164	**6,251**
April	4.75	9,256	43.96	9,414	44.72	0.75	7,071	**5,315**
May	4.75	9,270	44.03	9,454	44.90	0.87	0	**0**
June	5.00	9,284	46.42	9,478	47.39	0.97	60,965	**59,069**
July	6.50	9,313	60.53	9,487	61.66	1.13	187,673	**212,140**
August	6.50	9,320	60.58	9,487	61.67	1.09	153,272	**166,416**
September	4.75	9,277	44.06	9,452	44.90	0.83	114,331	**95,428**
October	5.00	9,257	46.29	9,411	47.06	0.77	96,667	**74,521**
November	6.00	9,251	55.51	9,384	56.31	0.80	0	**0**
December	6.50	9,247	60.10	9,380	60.97	0.86	0	**0**
							Unit 3 total	**623,503**

4.7 NET PRESENT COST

The Net Present Cost (NPC) of a wet cooling system retrofit at SGS is the sum of all annual expenditures over the 20-year life span of the project and discounted according to the year in which the expense is incurred and the selected discount rate. The NPC represents the total change in revenue streams, in 2007 dollars, that SGS can expect over 20 years as a direct result of converting to wet cooling towers. The following values were used to calculate the NPC at a 7 percent discount rate:

- *Capital and Start-up.* Includes all capital, indirect, contingency, and shutdown costs. All costs in this category are incurred in Year 0. (See Table O–16.)
- *Annual O&M.* Base cost values for Year 1 and Year 12 are adjusted for subsequent years using a 2 percent year-over-year escalator. Because SGS has a relatively low capacity utilization factor, O&M costs for the NPV calculation were estimated at 50 percent of their maximum value. (See Table O–17.)
- *Annual Energy Penalty.* Sufficient information is not available to this study to forecast future generating capacity at SGS. In lieu of annual estimates, this study uses the net MWh output from 2006 for Year 1 through Year 20, including a year-over-year wholesale price escalation of 5.8 percent (based on the Producer Price Index). (See Table O–20 through Table O–22.)

Using these values, the NPC_{20} for SGS is $194 million. Appendix C contains detailed annual calculations used to develop this cost.

4.8 ANNUAL COST

The annual cost incurred by SGS for the retrofit of the once-through cooling system is the sum of the annual amortized capital cost plus the annual average of O&M and energy penalty expenditures. Capital costs are amortized at a 7 discount rate over 20 years. O&M and energy penalty costs are calculated in the same manner as for the NPC_{20} (Section 4.7).

Table O–23. Annual Cost

Discount rate (%)	Capital ($)	Annual O&M ($)	Annual energy penalty ($)	Annual cost ($)
7.00	15,200,000	900,000	2,600,000	**18,700,000**

4.9 COST-TO-GROSS REVENUE COMPARISON

Financial data available to conduct a detailed analysis of the economic impact that a wet cooling system retrofit will have on annual revenues for SGS are limited. As a publicly-owned utility, LADWP's gross revenues will include costs for transmission and distribution. An approximation of gross annual revenues was calculated using public data sources (US EIA 2005) that showed LADWP's average annual retail rate was $96/MWh. This rate was applied to the monthly net generating outputs for each unit in 2005 (CEC 2005) to arrive at a facility-wide revenue estimate. This estimate does not reflect seasonal adjustments that may translate to higher or lower per-

MWh retail rates through the year, nor does it include other liabilities such as taxes or other operational costs.

The estimated gross revenue for SGS is summarized in Table O–24. A comparison of annual costs to annual gross revenue is summarized in Table O–25.

Table O–24. Estimated Gross Revenue

	Wholesale price	Net generation (MWh)			Estimated gross revenue ($)			
	($/MWh)	Unit 1	Unit 2	Unit 3	Unit 1	Unit 2	Unit 3	SGS total
January	96	43,793	55,471	5,606	4,204,171	5,325,182	538,193	**10,067,545**
February	96	2,675	58,955	0	256,835	5,659,718	0	**5,916,553**
March	96	726	59,964	9,164	69,684	5,756,544	879,767	**6,705,995**
April	96	0	60,751	7,071	0	5,832,130	678,824	**6,510,954**
May	96	0	68,799	0	0	6,604,719	0	**6,604,719**
June	96	27,209	70,651	60,965	2,612,032	6,782,496	5,852,613	**15,247,141**
July	96	10,083	63,113	187,673	968,008	6,058,889	18,016,594	**25,043,491**
August	96	12,240	67,671	153,272	1,175,042	6,496,437	14,714,156	**22,385,634**
September	96	0	60,432	114,331	0	5,801,517	10,975,779	**16,777,296**
October	96	26,023	42,084	96,667	2,498,163	4,040,090	9,280,060	**15,818,314**
November	96	72,208	0	0	6,931,965	0	0	**6,931,965**
December	96	23,786	36,084	0	2,283,492	3,464,026	0	**5,747,518**
SGS total		**218,743**	**643,975**	**634,749**	**14,240,870**	**39,511,034**	**44,387,767**	**98,139,672**

Table O–25. Cost-Revenue Comparison

Estimated gross annual revenue ($)	Initial capital		O&M		Energy penalty		Total annual cost	
	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross
143,800,000	15,200,000	10.6	900,000	0.6	2,600,000	1.8	**18,700,000**	**13.0**

5.0 OTHER TECHNOLOGIES

Within the scope of this study, and using the OPC resolution's stated goal of reducing impingement and entrainment by 90–95 percent as a benchmark, the effectiveness of other technologies commonly used to address such impacts could not be conclusively determined for use at SGS. As with many existing facilities, the location and configuration of the site complicates the use of some technologies that might be used successfully elsewhere. A more detailed analysis that also comprises a biological evaluation may determine the applicability of one or more of these technologies to SGS. A brief summary of the applicability of these technologies follows.

5.1 MODIFIED RISTROPH SCREENS—FINE MESH

The principal concern with this technology is the successful return of viable organisms captured on the screens to the source water body. SGS currently withdraws its cooling water through a submerged conduit extending approximately 1,600 feet offshore at a depth of 20 feet. Returning any collected organisms to a similar location would be impractical. It is unclear whether organisms could be returned to a near-shore location closer to the facility and remain viable.

5.2 BARRIER NETS

Barrier nets are unproven in an open ocean environment.

5.3 AQUATIC FILTRATION BARRIERS

Aquatic filtration barriers (AFBs) are unproven in an open ocean environment.

5.4 VARIABLE SPEED DRIVES

Variable speed drives (VSDs) were not considered for analysis at SGS because the technology alone cannot be expected to achieve the desired level of reductions in impingement and entrainment, nor could it be combined with another technology to yield the desired reductions. Pumps that have been retrofitted with VSDs can reduce overall flow intake volumes by 10–35 percent over the current once-through configuration (USEPA 2001). The actual reduction, however, will vary based on the cooling water demand at different times of the year. At peak demand, the pumps will essentially function as standard circulating water pumps and withdraw water at the maximum rated capacity, thus negating any potential benefit. Use of VSDs may be an economically desirable option when pumps are retrofitted or replaced for other reasons, but they were not considered further for this study.

5.5 CYLINDRICAL FINE-MESH WEDGEWIRE

Fine-mesh cylindrical wedgewire screens have not been deployed or evaluated at open coastal facilities for applications as large as would be required at SGS (approximately 380 mgd). To function as intended, cylindrical wedgewire screens must be submerged in a water body with a consistent ambient current of 0.5 feet per second (fps). Ideally, this current would be unidirectional, so that screens may be oriented properly and any debris impinged on the screens will be carried downstream when the airburst cleaning system is activated.

Fine-mesh wedgewire screens for SGS would be located offshore in the Pacific Ocean, west of the facility. Limited information regarding the subsurface currents in the near-shore environment near SGS is available. Data suggest that these currents are multidirectional depending on the tide and season and fluctuate in terms of velocity, with prolonged periods below 0.5 fps (SCCOOS 2006). To attain sufficient depth (approximately 20 feet) and an ambient current that might allow deployment, screens would need to be located 2,000 feet or more offshore. Discussions with vendors who design these systems indicated that distances more than 1,000 to 1,500 feet become problematic due to the inability of the airburst system to maintain adequate pressure for sufficient cleaning (Someah 2007). Together, these considerations preclude further evaluation of fine-mesh cylindrical wedgewire screens at SGS.

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Appendix A. Once-Through and Closed-Cycle Thermal Performance

		Unit 1			Unit 2			Unit 3		
		Once through	Closed cycle	Net increase	Once through	Closed cycle	Net increase	Once through	Closed cycle	Net increase
JAN	Backpressure (in. HgA)	1.47	2.12	**0.65**	1.47	2.12	**0.65**	1.34	1.95	**0.61**
	Heat rate Δ (%)	*-0.05*	*1.08*	***1.14***	*-0.05*	*1.08*	***1.13***	*-0.36*	*0.54*	***0.90***
FEB	Backpressure (in. HgA)	1.51	2.18	**0.67**	1.51	2.18	**0.67**	1.38	2.01	**0.63**
	Heat rate Δ (%)	*0.01*	*1.20*	***1.19***	*0.01*	*1.20*	***1.19***	*-0.33*	*0.65*	***0.98***
MAR	Backpressure (in. HgA)	1.56	2.23	**0.67**	1.56	2.23	**0.67**	1.43	2.06	**0.64**
	Heat rate Δ (%)	*0.08*	*1.30*	***1.22***	*0.08*	*1.30*	***1.22***	*-0.29*	*0.75*	***1.04***
APR	Backpressure (in. HgA)	1.63	2.35	**0.72**	1.63	2.35	**0.72**	1.49	2.17	**0.68**
	Heat rate Δ (%)	*0.19*	*1.52*	***1.33***	*0.19*	*1.52*	***1.33***	*-0.22*	*0.98*	***1.20***
MAY	Backpressure (in. HgA)	1.76	2.56	**0.80**	1.76	2.56	**0.80**	1.61	2.37	**0.76**
	Heat rate Δ (%)	*0.41*	*1.90*	***1.50***	*0.41*	*1.90*	***1.50***	*-0.06*	*1.41*	***1.47***
JUN	Backpressure (in. HgA)	1.86	2.69	**0.84**	1.86	2.69	**0.84**	1.71	2.50	**0.79**
	Heat rate Δ (%)	*0.58*	*2.12*	***1.54***	*0.58*	*2.12*	***1.54***	*0.08*	*1.66*	***1.58***
JUL	Backpressure (in. HgA)	2.04	2.74	**0.70**	2.04	2.74	**0.70**	1.88	2.54	**0.66**
	Heat rate Δ (%)	*0.94*	*2.20*	***1.27***	*0.94*	*2.20*	***1.27***	*0.40*	*1.76*	***1.37***
AUG	Backpressure (in. HgA)	2.09	2.75	**0.66**	2.09	2.75	**0.66**	1.92	2.55	**0.62**
	Heat rate Δ (%)	*1.02*	*2.21*	***1.19***	*1.02*	*2.21*	***1.19***	*0.48*	*1.77*	***1.29***
SEP	Backpressure (in. HgA)	1.81	2.56	**0.75**	1.81	2.56	**0.75**	1.66	2.37	**0.71**
	Heat rate Δ (%)	*0.49*	*1.89*	***1.40***	*0.49*	*1.89*	***1.40***	*0.01*	*1.40*	***1.39***
OCT	Backpressure (in. HgA)	1.64	2.33	**0.69**	1.64	2.33	**0.69**	1.51	2.16	**0.65**
	Heat rate Δ (%)	*0.21*	*1.49*	***1.28***	*0.21*	*1.49*	***1.28***	*-0.20*	*0.95*	***1.16***
NOV	Backpressure (in. HgA)	1.58	2.19	**0.61**	1.58	2.19	**0.61**	1.45	2.02	**0.57**
	Heat rate Δ (%)	*0.11*	*1.21*	***1.10***	*0.11*	*1.21*	***1.10***	*-0.27*	*0.66*	***0.94***
DEC	Backpressure (in. HgA)	1.53	2.16	**0.63**	1.53	2.16	**0.63**	1.40	1.99	**0.60**
	Heat rate Δ (%)	*0.03*	*1.16*	***1.13***	*0.03*	*1.16*	***1.13***	*-0.32*	*0.61*	***0.93***

Note: Heat rate delta represents change from design value calculated according to estimated ambient conditions for each month.

Appendix B. Itemized Capital Costs

Description	Unit	Qty	Equipment		Bulk material		Labor			--	Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	Other	
CIVIL / STRUCTURAL / PIPING	--	--	--	--	--	--	--	--	--	--	--
Allocation for other accessories (bends, water hammers…)	lot	1	--	--	500,000	500,000	4,000.00	85	340,000	--	**840,000**
Allocation for pipe racks (approx 3000 ft) and cable racks	t	300	--	--	2,500	750,000	17.00	105	535,500	--	**1,285,500**
Allocation for retaining walls	lot	1	--	--	500,000	500,000	5,000.00	100	500,000	--	**1,000,000**
Allocation for sheet piling and dewatering	lot	2	--	--	500,000	1,000,000	5,000.00	100	1,000,000	--	**2,000,000**
Allocation for site surface finishing around cooling towers, repair of grass and slope protections damaged during works	lot	1	--	--	100,000	100,000	1,000.00	100	100,000	--	**200,000**
Allocation for testing pipes	lot	2	--	--	--	--	2,000.00	95	380,000	--	**380,000**
Allocation for Tie-Ins to existing condenser's piping	lot	1	--	--	250,000	250,000	2,000.00	85	170,000	--	**420,000**
Allocation for trust blocks	lot	2	--	--	25,000	50,000	250.00	95	47,500	--	**97,500**
Backfill for PCCP pipe (reusing excavated material)	m3	4,745	--	--	--	--	0.04	200	37,960	--	**37,960**
Bedding for PCCP pipe	m3	629	--	--	25	15,725	0.04	200	5,032	--	**20,757**
Bend for PCCP pipe 72" diam (allocation)	ea	12	--	--	18,000	216,000	40.00	95	45,600	--	**261,600**
Building architectural (siding, roofing, doors, painting…etc)	ea	4	--	--	57,500	230,000	690.00	75	207,000	--	**437,000**
Bulk excavation to get 90 ft finished level including allocation of 15$/m3 for transport toward disposal site	m3	20,000	--	--	--	--	0.04	200	160,000	300,000	**460,000**
Butterfly valves 30" c/w allocation for actuator & air lines	ea	31	30,800	954,800	--	--	50.00	85	131,750	--	**1,086,550**
Butterfly valves 36" c/w allocation for actuator & air lines	ea	16	33,600	537,600	--	--	50.00	85	68,000	--	**605,600**
Butterfly valves 48" c/w allocation for actuator & air lines	ea	4	46,200	184,800	--	--	50.00	85	17,000	--	**201,800**
Butterfly valves 60" c/w allocation for actuator & air lines	ea	8	75,600	604,800	--	--	60.00	85	40,800	--	**645,600**
Butterfly valves 72" c/w allocation for actuator & air lines	ea	8	96,600	772,800	--	--	75.00	85	51,000	--	**823,800**
Butterfly valves 96" c/w allocation for actuator & air lines	ea	4	151,200	604,800	--	--	75.00	85	25,500	--	**630,300**

Description	Unit	Qty	Equipment		Bulk material		Labor			--	Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	Other	
Carbon Steel Pipe 12" diam. Butt welded	ft	1,200	--	--	100	120,000	1.40	85	142,800	--	**262,800**
Check valves 24"	ea	6	40,000	240,000	--	--	12.00	85	6,120	--	**246,120**
Check valves 30"	ea	3	44,000	132,000	--	--	16.00	85	4,080	--	**136,080**
Check valves 48"	ea	4	66,000	264,000	--	--	24.00	85	8,160	--	**272,160**
Check valves 72"	ea	4	138,000	552,000	--	--	32.00	85	10,880	--	**562,880**
Concrete basin walls (all in)	m3	599	--	--	225	134,775	8.00	75	359,400	--	**494,175**
Concrete elevated slabs (all in)	m3	434	--	--	250	108,500	10.00	75	325,500	--	**434,000**
Concrete for transformers and oil catch basin (allocation)	m3	200	--	--	250	50,000	10.00	75	150,000	--	**200,000**
Concrete for trestles (excluding piles)	m3	517	--	--	250	129,250	10.00	75	387,750	--	**517,000**
Concrete slabs on grade (all in)	m3	3,534	--	--	200	706,800	4.00	75	1,060,200	--	**1,767,000**
Excavation for PCCP pipe	m3	7,605	--	--	--	--	0.04	200	60,840	--	**60,840**
Fencing around transformers	m	50	--	--	30	1,500	1.00	75	3,750	--	**5,250**
Flange for PCCP joints 24"	ea	3	--	--	1,725	5,175	12.00	95	3,420	--	**8,595**
Flange for PCCP joints 30"	ea	28	--	--	2,260	63,280	16.00	95	42,560	--	**105,840**
Foundations for pipe racks and cable racks	m3	700	--	--	250	175,000	8.00	75	420,000	--	**595,000**
FRP flange 30"	ea	94	--	--	1,679	157,840	50.00	85	399,500	--	**557,340**
FRP flange 48"	ea	16	--	--	3,000	48,000	75.00	85	102,000	--	**150,000**
FRP flange 60"	ea	16	--	--	7,786	124,569	100.00	85	136,000	--	**260,569**
FRP flange 72"	ea	28	--	--	20,888	584,855	200.00	85	476,000	--	**1,060,855**
FRP flange 96"	ea	8	--	--	40,000	320,000	500.00	85	340,000	--	**660,000**
FRP pipe 24" diam.	ft	2,000	--	--	95	189,200	0.30	85	51,000	--	**240,200**
FRP pipe 30" diam.	ft	1,600	--	--	121	194,044	0.40	85	54,400	--	**248,444**
FRP pipe 48" diam.	ft	80	--	--	331	26,488	0.60	85	4,080	--	**30,568**
FRP pipe 60" diam.	ft	3,000	--	--	615	1,844,700	0.90	85	229,500	--	**2,074,200**
FRP pipe 72" diam.	ft	310	--	--	851	263,934	1.20	85	31,620	--	**295,554**
FRP pipe 96" diam.	ft	1,400	--	--	2,838	3,973,200	1.75	85	208,250	--	**4,181,450**
Harness clamp 72" c/w internal testable joint	ea	100	--	--	2,440	244,000	18.00	95	171,000	--	**415,000**
Joint for FRP pipe 24" diam.	ea	50	--	--	901	45,030	35.00	85	148,750	--	**193,780**
Joint for FRP pipe 30" diam.	ea	40	--	--	1,126	45,026	50.00	85	170,000	--	**215,026**
Joint for FRP pipe 48" diam.	ea	2	--	--	2,129	4,257	70.00	85	11,900	--	**16,157**
Joint for FRP pipe 72" diam.	ea	10	--	--	3,122	31,218	200.00	85	170,000	--	**201,218**
Joint for FRP pipe 96" diam.	ea	35	--	--	17,974	629,090	600.00	85	1,785,000	--	**2,414,090**
Joint for FRP pipe 60" diam.	ea	75	--	--	1,797	134,805	100.00	85	637,500	--	**772,305**
PCCP pipe 72" diam.	ft	2,000	--	--	507	1,014,000	1.30	95	247,000	--	**1,261,000**
Piles for trestles	ea	72	--	--	5,000	360,000	50.00	100	360,000	--	**720,000**

Description	Unit	Qty	Equipment		Bulk material		Labor			--	Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	Other	
Pipe bridge gantries	m.t.	447	--	--	2,500	1,117,500	17.00	105	797,895	--	**1,915,395**
Pipe bridge trestles	m.t.	163	--	--	2,500	407,500	17.00	105	290,955	--	**698,455**
Riser (FRP pipe 30" diam X 55 ft)	ea	26	--	--	15,350	399,095	150.00	85	331,500	--	**730,595**
Structural steel for building	t	190	--	--	2,500	475,000	20.00	105	399,000	--	**874,000**
CIVIL / STRUCTURAL / PIPING TOTAL	**--**	**--**	**--**	**4,847,600**	**--**	**17,739,355**	**--**	**--**	**14,400,952**	**300,000**	**37,287,907**
DEMOLITION	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**
Demolition of tanks and shelter on south-west corner of Terrace Drive and Grand Ave	lot	1	--	--	--	--	250.00	100	25,000	--	**25,000**
Demolish 1 tank approx 100 ft diameter (located west of 230 kv switchyard	lot	1	--	--	--	--	1,500.00	100	150,000	--	**150,000**
Demolish building located north-east of the 138 kv substation (approx. 200 ft X 50 ft)	lot	1	--	--	--	--	2,000.00	100	200,000	--	**200,000**
Demolish cooling towers located east of 138 kv switchyard	lot	1	--	--	--	--	500.00	85	42,500	--	**42,500**
DEMOLITION TOTAL	**--**	**--**	**--**	**0**	**--**	**0**	**--**	**--**	**417,500**	**--**	**417,500**
ELECTRICAL	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**
4.16 kv cabling feeding MCC's	m	3,000	--	--	75	225,000	0.40	85	102,000	--	**327,000**
4.16kV switchgear - 5 breakers	ea	1	280,000	280,000	--	--	230.00	85	19,550	--	**299,550**
480 volt cabling feeding MCC's	m	1,500	--	--	70	105,000	0.40	85	51,000	--	**156,000**
480V Switchgear - 1 breaker 3000A	ea	4	30,000	120,000	--	--	80.00	85	27,200	--	**147,200**
Allocation for automation and control	lot	1	--	--	750,000	750,000	7,500.00	85	637,500	--	**1,387,500**
Allocation for cable trays and duct banks	m	3,000	--	--	75	225,000	1.00	85	255,000	--	**480,000**
Allocation for lighting and lightning protection	lot	1	--	--	90,000	90,000	900.00	85	76,500	--	**166,500**
Dry Transformer 2MVA xxkV-480V	ea	4	100,000	400,000	--	--	100.00	85	34,000	--	**434,000**
Lighting & electrical services for pump house building	ea	4	--	--	20,000	80,000	250.00	85	85,000	--	**165,000**
Local feeder for 1200 HP motor 4160 V (up to MCC)	ea	4	--	--	42,000	168,000	150.00	85	51,000	--	**219,000**
Local feeder for 200 HP motor 460 V (up to MCC)	ea	26	--	--	15,000	390,000	140.00	85	309,400	--	**699,400**
Local feeder for 4000 HP motor 4160 V (up to MCC)	ea	4	--	--	50,000	200,000	200.00	85	68,000	--	**268,000**
Oil Transformer 10/13.3MVA xx-4.16kV	ea	3	190,000	570,000	--	--	150.00	85	38,250	--	**608,250**
Primary breaker(xxkV)	ea	6	45,000	270,000	--	--	60.00	85	30,600	--	**300,600**

Description	Unit	Qty	Equipment		Bulk material		Labor			--	Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	Other	
Primary feed cabling (assumed 13.8 kv)	m	5,000	--	--	175	875,000	0.50	85	212,500	--	**1,087,500**
ELECTRICAL TOTAL	**--**	**--**	**--**	**1,640,000**	**--**	**3,108,000**	**--**	**--**	**1,997,500**	**--**	**6,745,500**
MECHANICAL	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**
Allocation for ventilation of buildings	ea	4	25,000	100,000	--	--	250.00	85	85,000	--	**185,000**
Cooling tower for unit 1	lot	1	9,800,000	9,800,000	--	--	--	--	--	--	**9,800,000**
Cooling tower for unit 2	lot	1	9,800,000	9,800,000	--	--	--	--	--	--	**9,800,000**
Cooling tower for unit 3	lot	1	25,500,000	25,500,000	--	--	--	--	--	--	**25,500,000**
Overhead crane 30 ton in (in pump house)	ea	4	75,000	300,000	--	--	100.00	85	34,000	--	**334,000**
Pump 4160 V 1200 HP	ea	4	800,000	3,200,000	--	--	420.00	85	142,800	--	**3,342,800**
Pump 4160 V 4000 HP	ea	4	1,360,000	5,440,000	--	--	800.00	85	272,000	--	**5,712,000**
MECHANICAL TOTAL	**--**	**--**	**--**	**54,140,000**	**--**	**0**	**--**	**--**	**533,800**	**--**	**54,673,800**

Appendix C. Net Present Cost Calculation

Project Year	Capital / Startup ($)	O & M ($)	Energy Penalty ($)			Total ($)	Annual Discount Factor	Present Value ($)
			Unit 1	Unit 2	Unit 3			
0	160,600,000	--	--	--		160,600,000	1	**160,600,000**
1	--	689,000	205,815	600,765	623,503	2,119,083	0.9346	**1,980,495**
2	--	702,780	217,814	635,789	659,853	2,216,237	0.8734	**1,935,661**
3	--	716,836	230,513	672,856	698,323	2,318,527	0.8163	**1,892,614**
4	--	731,172	243,952	712,083	739,035	2,426,242	0.7629	**1,850,980**
5	--	745,796	258,174	753,598	782,121	2,539,689	0.713	**1,810,798**
6	--	760,712	273,226	797,533	827,718	2,659,188	0.6663	**1,771,817**
7	--	775,926	289,155	844,029	875,974	2,785,084	0.6227	**1,734,272**
8	--	791,444	306,012	893,236	927,044	2,917,736	0.582	**1,698,122**
9	--	807,273	323,853	945,311	981,090	3,057,528	0.5439	**1,662,989**
10	--	823,419	342,733	1,000,423	1,038,288	3,204,863	0.5083	**1,629,032**
11	--	839,887	362,715	1,058,748	1,098,820	3,360,170	0.4751	**1,596,417**
12	--	1,019,031	383,861	1,120,473	1,162,881	3,686,246	0.444	**1,636,693**
13	--	1,039,412	406,240	1,185,796	1,230,677	3,862,125	0.415	**1,602,782**
14	--	1,060,200	429,924	1,254,928	1,302,426	4,047,478	0.3878	**1,569,612**
15	--	1,081,404	454,989	1,328,090	1,378,357	4,242,840	0.3624	**1,537,605**
16	--	1,103,032	481,514	1,405,518	1,458,715	4,448,780	0.3387	**1,506,802**
17	--	1,125,093	509,587	1,487,460	1,543,759	4,665,898	0.3166	**1,477,223**
18	--	1,147,594	539,296	1,574,179	1,633,760	4,894,828	0.2959	**1,448,380**
19	--	1,170,546	570,737	1,665,953	1,729,008	5,136,244	0.2765	**1,420,172**
20	--	1,193,957	604,011	1,763,078	1,829,809	5,390,855	0.2584	**1,392,997**
Total								**193,755,463**

Appendix 1. Capital Cost Summary

Table 1-A. Facility-level Capital Cost

Facility	Direct capital ($)	Cooling tower ($)	Indirect ($)	Contingency ($)	Total initial capital cost ($)
Alamitos	98,200,000	30,900,000	38,700,000	42,000,000	209,800,000
Contra Costa	47,600,000	12,800,000	18,100,000	19,600,000	98,100,000
Diablo Canyon	448,800,000	61,000,000	178,400,000	206,500,000	894,700,000
Harbor	13,400,000	2,600,000	4,800,000	5,200,000	26,000,000
Haynes (all units)	68,300,000	25,200,000	28,100,000	30,400,000	152,000,000
Haynes (8 only)	20,400,000	8,200,000	7,800,000	8,500,000	44,900,000
Huntington	73,800,000	11,700,000	24,500,000	26,500,000	136,500,000
Mandalay	26,100,000	3,200,000	10,200,000	11,100,000	50,600,000
Moss Landing (all units)	126,500,000	25,000,000	49,600,000	53,700,000	254,800,000
Moss Landing 1-2	34,800,000	25,000,000	13,800,000	14,900,000	88,500,000
Pittsburg	63,600,000	13,600,000	23,100,000	25,100,000	125,400,000
San Onofre	167,900,000	170,000,000	118,300,000	136,900,000	593,100,000
Scattergood	53,700,000	45,100,000	29,600,000	32,100,000	160,500,000

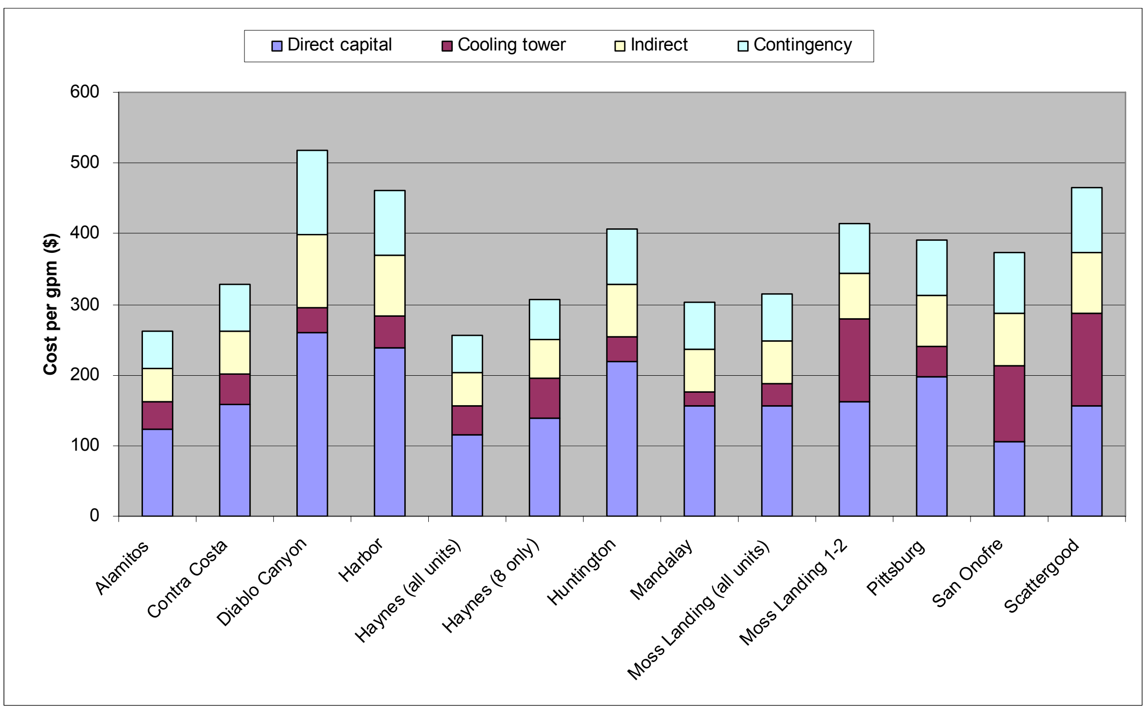

Figure 1-A. Facility-level Capital Cost ($ per gpm)

Appendix 2. Energy Penalty Summary

Table 2-A. Facility-level Energy Penalty

Facility	Thermal efficiency (peak) (%)	Thermal efficiency (annual) (%)	Fan (%)	Pump (%)	Total penalty (peak) (%)	Total penalty (annual) (%)
Alamitos	1.70	1.39	0.50	0.43	2.63	2.33
Contra Costa	0.56	0.76	0.55	0.80	1.91	2.11
Diablo Canyon	3.60	3.61	0.74	0.66	5.00	5.01
Harbor	0.59	0.48	0.33	0.33	1.25	1.14
Haynes	1.05	0.87	0.44	0.30	1.78	1.60
Haynes 8	0.56	0.45	0.26	0.01	0.82	0.72
Huntington Beach	1.59	1.20	0.50	0.64	2.73	2.34
Mandalay	0.43	0.73	0.51	0.40	1.34	1.64
Moss Landing	0.93	0.94	0.46	0.19	1.58	1.58
Moss Landing 1 & 2	0.55	0.57	0.29	0.21	1.05	1.06
Pittsburg	0.35	0.41	0.27	0.58	1.20	1.26
San Onofre	3.74	2.88	0.82	1.77	6.33	5.48
Scattergood	1.32	1.23	0.51	1.47	3.30	3.20

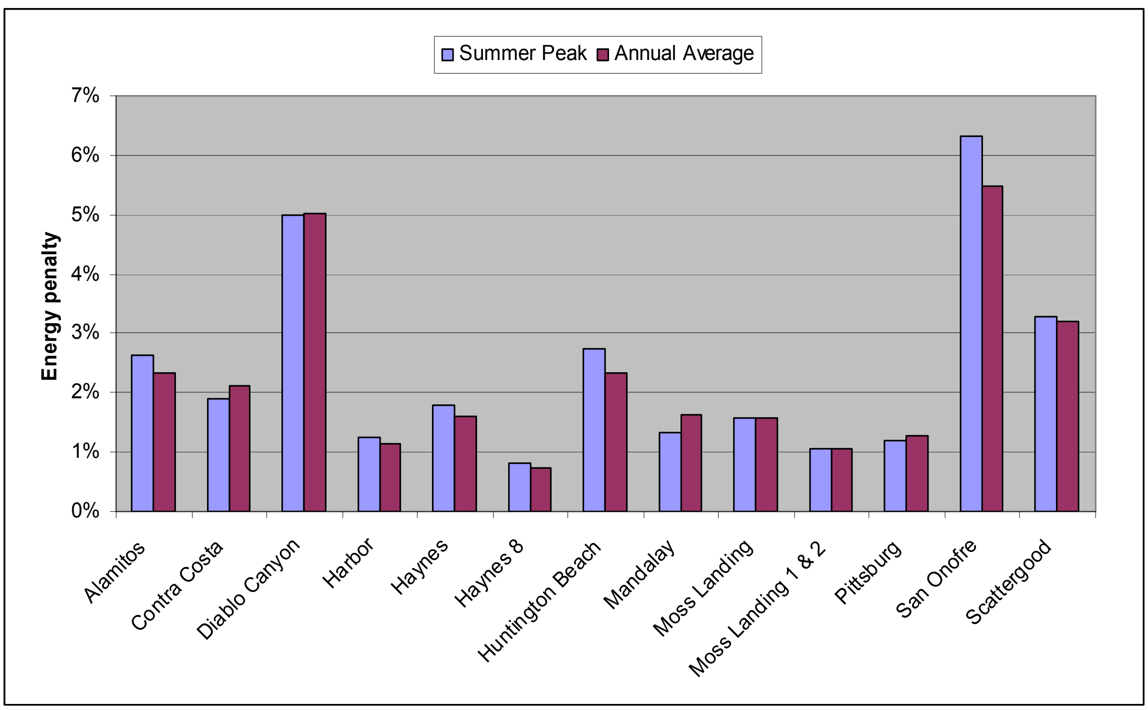

Figure 2-A. Energy Penalty Summary (% of capacity)

Appendix 3. Net Present Cost Summary

Table 3-A. Facility Level Net Present Cost

Facility	Startup cost ($)	Construction downtime loss ($)	Energy Penalty + O&M cost ($)	Net present cost ($)
Alamitos	209,800,000	0	53,300,000	263,100,000
Contra Costa	98,100,000	0	6,200,000	104,300,000
Diablo Canyon	894,700,000	726,554,160	1,399,245,840	3,020,500,000
Harbor	26,000,000	0	2,600,000	28,600,000
Haynes (all units)	152,000,000	4,550,000	52,350,000	208,900,000
Haynes (8 only)	44,900,000	4,550,000	16,050,000	65,500,000
Huntington	136,500,000	0	23,900,000	160,400,000
Mandalay	50,600,000	0	10,600,000	61,200,000
Moss Landing (all units)	254,800,000	1,958,892	92,841,108	349,600,000
Moss Landing 1-2	88,500,000	1,958,892	32,141,108	122,600,000
Pittsburg	125,400,000	0	8,500,000	133,900,000
San Onofre	593,100,000	594,823,896	1,432,976,104	2,620,900,000
Scattergood	160,500,000	0	33,200,000	193,700,000

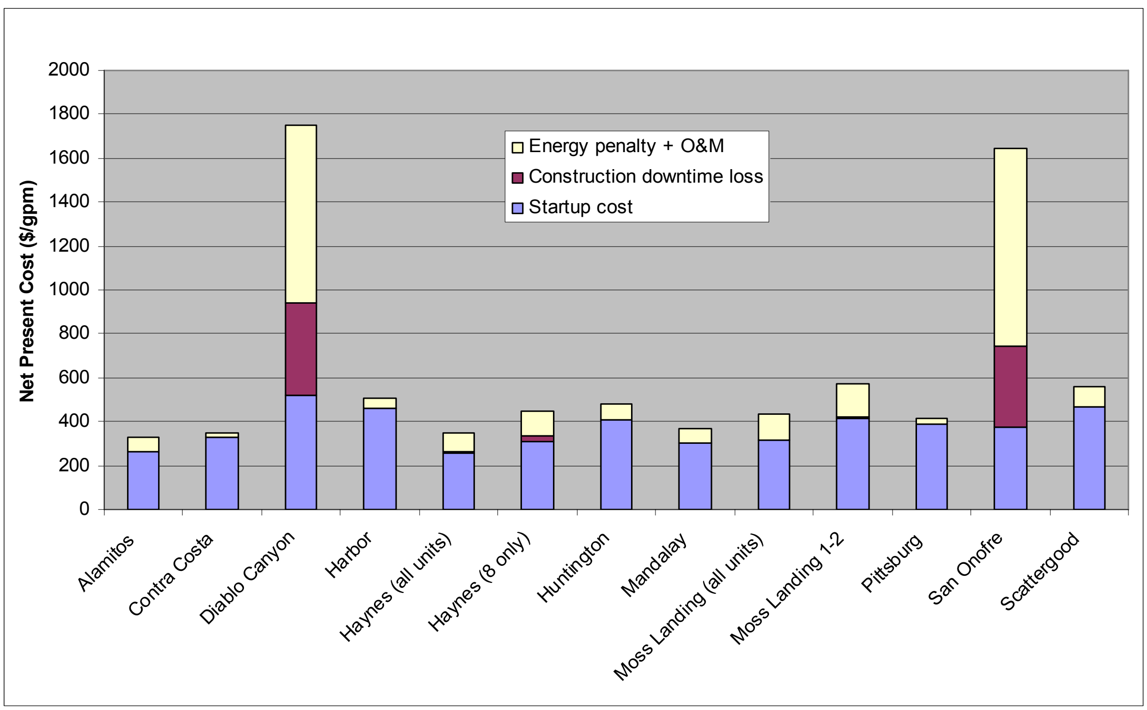

Figure 3-A. Net Present Cost Summary ($ per gpm)