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:

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

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