STATE OF CALIFORNIA – THE RESOURCES AGENCY

ARNOLD SCHWARZENEGGER, *Governor*

CALIFORNIA ENERGY COMMISSION
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316(b)
Once Through Cooling
Deadline: 9/25/06

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SEP 2006
SWRCB
Executive Ofc.

September 25, 2006

Chair Tam Doduc
Vice-Chair Gerald Secundy
State Water Resources Control Board
1001 I Street
Sacramento, CA 95814

Attn: Song Her, Clerk to the Board

CALIFORNIA ENERGY COMMISSION COMMENTS ON THE STATE WATER RESOURCES CONTROL BOARD SCOPING DOCUMENT AND PROPOSED STATEWIDE POLICY ON CLEAN WATER ACT 316(b) REGULATIONS

Dear Chair Doduc and Vice-Chair Secundy,

The California Energy Commission (Energy Commission) is pleased to provide the State Water Resources Control Board (State Water Board) with our perspective and comments on the State Water Board's proposed policy on implementing section 316(b) of the federal Clean Water Act. We compliment the State Water Board on their inclusive public process for considering how the federal rule should be modified and implemented in California, and would like to recognize the State Water Board staff for their work in drafting the proposed policy.

A core mission of our agency is to ensure a reliable supply of electricity for California that is affordable and that minimizes harm to the environment. In evaluating the proposed rule and its implementation, our paramount concern is to maintain a reliable supply of electricity for the benefit of our economy and public welfare. Our electricity system was stressed to near its maximum during the July 2006 heat storm. Electricity supplies are barely sufficient to meet demand in Southern California during such times of peak summer demand. In our *2005 Integrated Energy Policy Report*, we identified the need for utilities to procure about 24,000 megawatts (MW) of peak resources at the statewide level in order to replace expiring contracts, meet peak demand growth and replace aging facilities. Given these expectations, we need to work closely with the State Water Board to ensure that implementation of the proposed 316(b) rule will not result in the untimely loss of existing facilities that play an important role in maintaining electric system reliability and that there will be sufficient time for new replacement capacity to be built.

Notwithstanding our concerns for reliability, the Energy Commission supports efforts to reduce the impacts of once-through cooling on marine and estuarine environments in California. In our view, the science supports the action taken by the U.S. Environmental Protection Agency to modify the federal Clean Water Act section 316(b) Phase II rule regulating cooling water intakes for existing, large power plants using once-through cooling. The degraded state of our own coastal and estuarine waters further supports efforts to modify the federal rule in order to help meet California's policy goals for improving environmental quality in the aquatic ecosystems along our coastline. In our *2005 Integrated Energy Policy Report*, the Energy Commission identified once-through cooling impacts as an important policy issue that should be addressed through collaborative work with the State Water Board and other agencies.

California's coastal fleet includes 21 power plants with a total capacity of 21,250 megawatts (MW), which is about one third of our in-state generating capacity. In 2004, the coastal fleet provided 22 percent of total electricity sales (half of which came from the nuclear plants). For 2006, eight plants have local Reliability-Must-Run contracts from the California Independent System Operator (CAISO) totaling 3,038 MW. Nearly all of the coastal facilities use once-through cooling systems. The fleet includes our two nuclear facilities and four natural gas-fired plants with generating units that use efficient combined cycle technology. However, 15 of the facilities in the coastal fleet use older baseload, steam boiler technology that is far less efficient to operate than the newer combined cycle plants. These older plants are now being used as peaking and load following facilities, and they play a critical role in meeting summer peak demands and providing reserve capacity for periods of unplanned system outages. On an average annual basis, these older steam plants tend to run at low capacity levels.

California's power plant fleet is in the midst of a modernization trend. A policy goal of our agency is to encourage the orderly retirement of aging, inefficient power plants – such as the 15 steam boiler plants along the coast – and replace them with modern, efficient combined cycle or peaking facilities by 2012. At the statewide level, 46 percent of the 4,506 MW under licensing review at our agency are for peaking facilities. Nearly all new California projects use cooling towers and half of the projects under licensing review at the Energy Commission are using recycled or reclaimed water in response to our agency's 2003 policy directive to minimize the use of fresh water for power plant cooling. Two new large combined cycle plants use air cooling and a third air-cooled plant is under construction in the San Diego area.

Along the coast, 11 of the 21 plants have constructed, secured licenses, or announced plans to modernize their generating technologies. It is when plants modernize that it is most cost-effective to change cooling systems; three coastal generators have recently announced plans to modernize their facilities, and two will eliminate the once-through cooling systems during the upgrade (the third may retire the once-through cooling system by 2012). This trend provides an opportunity to integrate strategies for reducing once-through cooling impacts with our agency's goals for developing a modern, efficient fleet of power plants.

To accomplish this goal, the proposed rule should be implemented in a manner that allows generators, regulators and the electricity market sufficient time to comply with any new regulations so that resource adequacy targets and reserve margins can be maintained during the transition. Without an appropriate implementation plan, the state may not be able to meet the multiple policy goals of fleet modernization, electric system reliability, and improvements to ocean environmental quality. We cannot afford to have additional generating units retire in response to the proposed regulations without new resources being available to meet summer peak demands and provide reserve capacity for unplanned system outages.

Of the 21 plants in the coastal fleet, two have shut down and two have announced plans to repower without using once-through cooling.[1] (See Tables 1 and 5 in the technical portion of our letter.) The two nuclear plants may be able to meet their compliance obligations by using off-site mitigation. These six plants would be exempt from the entrainment reduction provisions of the proposed rule.

As currently drafted, the proposed rule would exempt power plants running below a 15 percent capacity factor – averaged over a five year period – from needing to comply with the entrainment provisions. Based on operating data for the 2001 – 2005 period, the remaining 15 plants all had capacity factors higher than 15 percent – ranging from 19 to 35 percent. However, ten of these plants had annual capacity factors below 15 percent in 2005. (See Table 5 and Appendix A.) If plant operators commit to keeping operations below 15 percent, they may be exempted from the entrainment reduction provisions of the proposed rule, which may become an attractive compliance option for some facilities. We do not have enough cost or operations data to assess whether some of these plants may shut down in response to the proposed policy.

Four of the plants running below the 15 percent capacity factor in 2005 hold local RMR contracts from the CAISO. If they choose to commit to keeping operations below 15 percent as a compliance option, it may be appropriate to explore crafting some emergency exemptions in cases where conditions or infrastructure failure obligate the CAISO to dispatch these plants and push them above the 15 percent threshold.

Another important consideration is cost of compliance. Owners of the older steam plants are having trouble securing long-term contracts that would allow them to finance their modernization goals. Last year's Assembly Bill 1576 provides a mechanism for coastal plants that repower and improve environmental performance to receive cost-of-service contracts via the California Public Utility Commission's procurement process. The CAISO's RMR contracts provide another potential funding mechanism for compliance costs.

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[1] Hunters Point and Long Beach have shut down, and Humboldt Bay and South Bay have announced plans to replace their generating systems without using once-through cooling. Encina will add 400 MW of new peaking generation, but it is not clear when the steam units and once-through cooling system would be retired.

The Ocean Protection Council is beginning a coastal plant retrofit feasibility and cost study that our agency is supporting technically and financially. This study should provide additional important information on one aspect of the costs of compliance. Our own Public Interest Energy Research program is funding additional investigative work on engineering issues and the costs of alternative cooling systems.

In sum, we view the State Water Board's proposed policy as an opportunity to integrate our State's environmental policy goals for improving marine and estuarine ecosystem health with the policy objectives for modernizing our coastal power plant fleet. Our goal is to ensure that the reliability of our electricity supply system is maintained during thoughtful implementation of the proposed rule Our staff has participated actively with your staff during this proceeding, and we recognize the need for ongoing collaboration during the remainder of this rule development. As stated at your July workshop, the Energy Commission offers to review the comments supplied by coastal generators and utilities and provide an objective interpretation for the State Water Board.

The next section of this letter includes a summary of development trends for the coastal and statewide power plant fleet, a preliminary assessment of the effects of the proposed rule on the state's electricity systems as well as specific comments and recommendations on the proposed rule.

Please contact me or Terry O'Brien, Deputy Director for Facility Siting, if you would like to further discuss these issues.

Sincerely,

JACKALYNE PFANNENSTIEL
Chairman

CC: California Independent System Operator, Mason Willrich, Chair
California Public Utilities Commission, Michael Peevy, Chair, and
Sean Gallager, Energy Division Director
California Resources Agency, Undersecretary for Energy, Joe Desmond
Ocean Protection Council, Michael Chrisman, Chair, and
Drew Bohan, Executive Policy Officer

ADDITIONAL ENERGY COMMISSION COMMENTS, RECOMMENDATIONS AND ENERGY SYSTEMS INFORMATION RELATED TO THE STATE WATER RESOURCES CONTROL BOARD SCOPING DOCUMENT AND PROPOSED STATEWIDE POLICY ON CLEAN WATER ACT 316(b) REGULATIONS

Introduction

This portion of the California Energy Commission's letter has three main sections and two appendices:

> **Part I** describes trends in coastal and statewide power plant development.
>
> **Part II** provides a preliminary assessment of how the proposed rule could affect coastal power plants and electricity system reliability.
>
> **Part III** provides comments, questions and recommendations on the State Water Board's proposed regulatory changes from the Federal 316(b) rule.
>
> **Appendix A** is a compilation of annual capacity factors at the unit and plant level for the coastal fleet from 2001 to 2005.
>
> **Appendix B** is a copy of the April 2006 Energy Commission letter to the State Lands Commission providing comment on their once-through cooling resolution.

Energy Commission staff requires additional time and data in order to analyze the potential effects of the proposed policy on coastal plant operations and electric system resource adequacy. As stated in oral comments at the July 31 workshop, the Energy Commission offers to review and assess the comments provided by industry and other stakeholders pertaining to possible effects of the proposed rule on power plants and electric system resource adequacy.

Summary of Proposed Changes from the Federal Rule

The Commission recognizes that the State Water Board staff's proposed policy for implementing the Federal 316(b) rule is motivated by strong scientific findings on the degraded state of California's coastal marine resources. However, the proposed changes by the State Water Board staff may affect the operational ability and status of power plants in California with potential impacts to the reliability of the state's electricity system. Consequently, we have numerous questions about data, methods, effectiveness, and possible effects of the changes on the state's electricity supply system. These proposed changes about which we are concerned include:

- Using the high end of performance standards for entrainment and impingement reductions
- Using actual average flow data for the calculation baseline, rather than permitted flows
- Requiring an actual 60 percent reduction in entrainment from plants operating above 15 percent annual capacity factor levels

- Elimination of the site-specific cost-benefit test as a best technology available compliance option
- Potential exemption of nuclear facilities from making changes to operations or cooling systems should safety issues be of concern
- Continued limited applications of off-site mitigation as a best technology available compliance option
- Requiring operators to reduce flows during periods of non-generation.

Part I – Trends in Coastal Plant Development, Statewide New Power Plant Development and Cooling Systems

Trends in Coastal Plant Development

The California coastal fleet subject to Clean Water Act 316(b) Phase II rules for large existing power plants using once-through cooling totals 21 plants with a capacity of 21,250 MW. At present, there are 2 nuclear plants, 15 steam boiler plants, and 4 plants that are combined cycle or a mix or combined cycle and steam boiler plants. Two plants – Hunter's Point and Long Beach – are shut down. Table 1 summarizes the coastal facilities.

California's coastal power plant fleet is in the midst of a modernization trend. Since the late 1990's, 11 facilities have constructed, permitted or announced plans to modernize their generating units by replacing steam boiler units. Moss Landing, Haynes, and Harbor have new operational combined cycle units, all of which continue to use once-through cooling. Huntington Beach refurbished the steam boilers in 2003 and continued the use of once-through cooling.

Two more plants have licenses from the Energy Commission to repower, although construction has not begun at El Segundo or Morro Bay. The Potrero project applied to refurbish the steam boiler units, but the proceeding was terminated in March 2006 without a decision. The plant is expected to close when local reliability criteria are met in the San Francisco Bay Area. Scattergood's units will also be replaced according to a consent decree, with the Los Angeles Department of Water Power (LADWP) acting as its own lead agency. LADWP has thus far retained once-through cooling during modernization of its coastal facilities.

In addition, the Diablo Canyon and San Onofre nuclear stations have submitted applications to refurbish the plants (i.e., replacing the steam generating equipment) which will not affect the once-through cooling systems.

Of special interest for this rulemaking proceeding at the State Water Board are the three companies that have submitted applications or announced plans to modernize their coastal facilities without using once-through cooling. PG&E has proposed to replace the Humboldt plant with natural gas-fired reciprocating engines that use traditional radiators for cooling. LS Power has proposed to replace the South Bay plant in San Diego with combined cycle units using air cooling. West Coast Power and NRG have announced plans to add 400 MW of single-cycle peaker units at their Encina facility that do not require large volumes of cooling water. The existing steam units and once-through cooling system may be dismantled in 2011 or 2012. In addition, PG&E may add a new 530 MW combined cycle unit (Unit 8) to the Contra Costa facility in the San Francisco Estuary and may convert the existing Units 6 and 7 away from once-through cooling to closed towers with reclaimed water.

This modernization of the coastal fleet presents opportunities to upgrade generating units to modern, fuel and cost efficient technologies and move away from once-through cooling to air or closed loop cooling systems. Most of the remaining steam plants are expected to modernize or close down over time due to the economics of their operations.

Statewide Power Plant Development Trends

The modernization of the coastal fleet mirrors the state-level evolution in California power generation system. Between 2001 and 2005, about 3,800 MW of capacity was mothballed or retired statewide – most of it being steam boiler units. Since 1998 when restructuring was enacted in California, 13,805 MW of new capacity has been added, including combined cycle units, combustion turbines and renewables like wind and geothermal. The Energy Commission has licensed a total of 22,842 MW of new capacity since 1998, although nearly 9,000 MW have not begun construction due to finance and contract procurement issues.[2]

Of particular interest to the State Water Proceeding are trends inherent in the 13 projects currently under licensing review at the Energy Commission (totaling 4,506 MW), and the 15 projects that have publicly announced their intent to file Applications for Certification before the Energy Commission (totaling 6,294 MW) (See Tables 2 and 3). Energy policy makers have identified the need for utilities to procure about 24,000 MW of peak resources in California to replace expiring contracts, meet peak demand growth and replace aging facilities,[3] such as the older steam units at the coastal plant sites. The market is responding and seven of the 13 projects currently under licensing review are for gas-fired peakers. The 2,098 MW of gas-fired peakers in licensing review include two very large 500 MW peaker proposals from Edison Mission (a subsidiary of Southern California Edison) to meet peak capacity demand in the Los Angeles basin. These projects will feature the new General Electric LMS100 turbines that require little cooling water, have low emissions profiles and relatively low heat rates. This trend illustrates the manner in which modern, large capacity projects are being proposed in areas with capacity constraints that are currently being met by some of the old steam boiler plants on the coast.

[2] Energy Facility Status Report, California Energy Commission Website, August 7, 2006 http://www.energy.ca.gov/sitingcases/all_projects.html

[3] 2005 Integrated Energy Policy Report at 52.

Table 1
STATUS AND KNOWN PLANS OF COASTAL PLANTS USING OTC – September 2006

Plant Name	Fuel Type	2006 Capacity (MW)	Location	Owner	Status and Announced Plans
Alamitos	Steam Boiler	1950	Long Beach	AES	
Contra Costa	Steam Boiler	680	SF Bay-Delta	Mirant & PG&E	License for new Unit 8 issued in May 2001, but construction suspended. Unit 8 transfered to PG&E.
Diablo Canyon	Nuclear	2195	SLO County	PG&E	CPUC has approved the replacement of the steam generators which will significantly extend the life of the project.
El Segundo	Steam Boiler	670	Santa Monica Bay	WCP/NRG	CEC issued replacement License w OTC Feb 2005. Construction has not begun.
Encina	Steam / Combust. Turbine	929	San Diego County	WCP/NRG	NRG will add 2 peaker units totaling 400 MW without OTC. Fate of existing steam units and OTC system unknown
Harbor	Combined Cycle	240	LA Harbor	LADWP	
Haynes	Combined Cycle / Steam	1611	Long Beach	LADWP	Units 3&4 replaced in 2005 re-using OTC. Units 1&2 replacement under way re-using OTC. No CEC jurisdiction.
Humboldt Bay	Steam Boiler	105	Humboldt Bay	PG&E	Will replace w no OTC. AFC expected 9/06.
Hunters Point	Steam / Combust. Turbine	0	SF Bay	PG&E	Shut down in 4/06.
Huntington Beach	Steam Boiler	880	Orange County	AES	Units 3 & 4 repowered w OTC in 2003. CEQA review and mitigation of OTC system pending.
Long Beach	Combined Cycle	0	LA Harbor	WCP/NRG	Shut Down
Mandalay	Steam / Combust. Turbine	560	Ventura County	Reliant	
Morro Bay	Steam Boiler	676	Morro Bay	LS Power	Repower License w OTC issued by CEC in 2004. Construction has not begun. RWB permit pending.
Moss Landing	Steam Boiler	1478	Monterey Bay	LS Power	
Moss Landing	Combined Cycle	1060	Monterey Bay	LS Power	CEC issued license w OTC in 2000. Operations began 2002.
Ormond Beach	Steam Boiler	1500	Ventura County	Reliant	
Pittsburg	Steam Boiler	1370	SF Bay-Delta	Mirant	
Potrero	Steam / Combust. Turbine	363	SF Bay	Mirant	Repower Proceeding terminated 3/06
Redondo Beach	Steam Boiler	1310	Santa Monica Bay	AES	
San Onofre	Nuclear	2167	San Diego County	SCE/SDG&E	CPUC is considering the approval of the replacement of the steam generators which will significantly extend the life of the project.
Scattergood	Steam Boiler	803	Santa Monica Bay	LADWP	LADWP is under a consent decree to replace the project. LADWP will likely try to keep the net increase in generating capacity below 50 MW to avoid CEC jurisdiction. They will likely plan to reuse the OTC to cool the new facility.
South Bay	Steam / Combust. Turbine	703	San Diego Bay	LS Power	AFC to replace w no OTC rec'd 6/06

Table 3 illustrates the projects that have announced plans to submit applications to the Energy Commission. The coastal Humboldt and Encina projects appear on this table, both of which will repower without once-through cooling. Encina is a 400 MW peaker project that will also feature the LMS100 turbines, and is intended to meet peak loads in Southern California. Three of the 15projects in this table are peakers totaling 620 MW. Also of interest in this table are the large renewable projects being proposed: 1,750 MW using the Stirling solar technology, and a 94 MW dairy waste biomass plant. As with Table 2, the trends from the announced projects illustrate that the market is dynamic and in transition from the old steam boiler plants to new modern facilities designed to meet California's energy policy requirements for new peak capacity, new combined cycle baseload capacity, and new renewable energy projects.

Table 2
Projects In Licensing Review at the California Energy Commission as of September 15, 2006
Excepted from Energy Facility Siting Status Report

Projects In Review (Arranged By Estimated Decision Date)	**Docket Number**	**Process**	**Capacity (MW)**	**Project Type**	**Location**	**Date Filed**	**Estimated Decision Date**	**Estimated On-line Date**
Pastoria Simple Cycle Addition (peaker)- Calpine	2005-AFC-1	12-mo AFC	160	Expansion	Kern	04/29/2005	07/06	Unknown
SF Reliability Project (peaker)	2004-AFC-01	12-mo AFC	145	Brownfield	San Francisco	03/18/2004	08/06	03/08
Los Esteros Combined Cycle - Calpine	2003-AFC-02	12-mo AFC	140	Expansion	Santa Clara	12/30/2003	08/06	Unknown
Niland Peaker - IID	2006-SPPE-1	SPPE	93	Greenfield	Imperial	03/13/2006	10/06	05/08
El Centro Unit 3 Repower - IID	2006-SPPE-2	SPPE	85	Expansion	Imperial	05/19/2006	12/06	05/09
Walnut Peaker - Edison Mission E.	2005-AFC-02	12-mo AFC	500	Brownfield	Los Angeles	11/22/2005	01/07	08/08
Sun Valley Peaker - Edison Mission E.	2005-AFC-03	12-mo AFC	500	Greenfield	Riverside	12/01/2005	02/07	08/08
Bottle Rock Geothermal Restart	1979-AFC-4C	Amendment	20	Repower	Lake	08/04/2006	02/07	Unkown
Avenal Combined Cycle - Federal Power	2001-AFC-20	12-mo AFC	600	Greenfield	Kings	10/09/2001	07/07	Unknown
Highgrove Peaker - AES	2006-AFC-2	12-mo AFC	300	Expansion	San Bernardino	05/25/2006	08/07	09/08
South Bay Replacement - L.S. Power	2006-AFC-3	12-mo AFC	620	Replacement	San Diego	06/30/2006	09/07	05/10
Vernon Power Plant - City of Vernon	2006-AFC-4	12-mo AFC	943	Brownfield	Los Angeles	06/30/2006	09/07	08/09
EIF Firebaugh Panoche – (peaker) Energy Investors Fund	2006-AFC-5	12-mo AFC	400	Greenfield	Fresno	08/06		
Under Review Total			**4,506**					

Table 3
Projects Announced But Not Yet Filed at the California Energy Commission as of September 15, 2006
Excepted from Energy Facility Siting Status Report

Projects Announced (Arranged by Estimated Filing Date)	**Process**	**Capacity (MW)**	**Project Type**	**Location**	**Estimated Filing Date**
Hybrid Gas-Solar - City of Victorville	12-mo AFC	550	Greenfield	San Bernardino	08/06
EIF Fresno/Bullard (peaker) - Energy Investors Fund	12-mo AFC	100	Brownfield	Fresno	08/06
CPV Colusa - E&L West coast	12-mo AFC	660	Greenfield	Colusa	09/06
Humboldt Power Plant - PG&E	12-mo AFC	163	Replacement	Humboldt	09/06
City of Palmdale Combined Cycle	12-mo AFC	550	Greenfield	San Bernardino	12/06
Stirling Solar Thermal One – Stirling Energy	12-mo AFC	850	Greenfield	San Bernardino	12/06
Stirling Solar Thermal Two – Stirling Energy	12-mo AFC	900	Greenfield	Imperial	02/07
Encina (peaker) - NRG	12-mo AFC	400	Brownfield	San Diego	03/07
Cosumnes - SMUD	12-mo AFC	500	Expansion	Sacramento	Unknown
Envirepel Biomass - Envirepel	12-mo AFC	90	Greenfield	San Diego	Unknown
Clean Hydrogen Power Project - BP Arco & Edison Mission Energy	12-mo AFC	500	Brownfield	Los Angeles	Unknown
Starwood Firebaugh Panoche (peaker)- Starwood Power	12-mo AFC	120	Greenfield	Fresno	Unknown
Russell City 2 – Calpine	12-mo AFC	600	Brownfield	Alameda	Unknown
Central Valley South Energy Center - Central California Power	Unknown	217	Unknown	Tulare	Unknown
MMC Chula Vista Expansion - MMC Energy, Inc.	12-mo AFC	94	Expansion	San Diego	Unknown
	Announced Total	**6,294**			

Part II – Preliminary Assessment of How the Proposed Rule Could Affect Coastal Plants and Electricity System Reliability.

California needs additional resources to meet expected load growth, especially in the region South of Path 26 in Southern California under adverse peak load conditions. As a result, new generation will be needed in order to meet expected growth in demand. New generation will also be needed to replace any resources that choose to retire.

Power plants owners have a variety of options and issues to consider in responding to regulatory changes to their use of cooling water. For example:

- Prior operations may earn the plant an exemption allowing it to continue operations without change.
- The owner of the plant may voluntarily accept a future reduced level of operation (below 15%) to gain an exemption accepting the opportunity costs and loss of generation revenue of doing so.
- The owner of the plant might shut down operations altogether.
- The existing plant might retrofit alternative cooling and/or otherwise mitigate its cooling impacts if allowed.
- The owner might propose to repower the existing plant, changing to alternative cooling and/or other mitigation of its cooling impacts.
- The owner might propose to replace the existing plant with a new power plant with alternative cooling and/or other mitigation of its cooling impacts.

Some of the options that power plant owners face may not be within their complete control to implement. For example, options that require major capital investment are likely to require a commitment from a load-serving entity to purchase the output of the power plant (either through bilateral contracts or competitive requests for offers) at the new cost level. Options that require changes in operations may be constrained by performance requirements of existing contracts with load serving entities or control areas operators.

The interaction of plant owner, load serving entity, and control area operator incentives and constraints will determine the cumulative impact of the rule changes on the electricity system. The details of these interactions are both plant- and entity-specific, making them difficult to assess and generalize.

For the purpose of discussion, the potential impact of the proposed rule on the electricity system can be divided into two sections. The first considers higher one-time and ongoing costs due to the structural and operational measures taken to comply with the rule. These are referred to below as energy costs and include:

- the direct costs of structural upgrades ("construction costs")[4]

[4] Considered energy costs as they will be ultimately passed on to consumers

- the incremental costs of replacement energy/capacity during construction/closure
- any additional variable operating costs due to structural and operational changes
- any incremental increase in ongoing energy costs due to redispatch of generating resources in order to comply with the rule

The second area is the potential reliability impacts of the rule, which would follow from a reduction in capacity due to compliance requirements. The components of this consideration are:

- reductions in available capacity during construction/closure
- reductions in the capacity of facilities/units that continue to operate during the post-compliance period
- Reductions in capacity due to the retirement of facilities/units that are rendered uneconomic due to compliance requirements.

These two broad sets of costs are interrelated, e.g., the cost of a structural upgrade of an economically marginal merchant unit will influence the decision to continue operation or shut it down.

One-Time and Energy Costs

Costs of Structural Upgrades

The direct costs of structural upgrades ("construction costs") and off-site mitigation will vary depending upon site-specific factors and choices made by the owner/operators as to the mix of structural, operational, and re-dispatch measures needed to comply with the rule. These costs will vary from site to site and may be substantial, in some cases perhaps equivalent to multiple years of the prevailing rental costs of existing units used largely to provide capacity ($25-$40/kw-yr).

The ability to pass the costs of structural upgrades on depends on the ownership of the unit and the extent to which it is needed to meet local capacity requirements:

- Utility owners could pass costs through to customers. Given the additional costs, it would be a possible to calculate their impact on rates.

- A merchant facility that is *necessary* for local reliability[5] could likely pass costs on through its local reliability contract, but, at present, not without substantial risk. Local Reliability-Must-Run (RMR) contracts administered by the CA ISO are currently renewed annually, with cost recovery for capital upgrades expensed over a multiple-year period only guaranteed for

[5] Necessary means that retirement of the plant would leave the ISO unable to meet standards for reliable service and thus compel the entity administering the local reliability contract (CA ISO, utility) to allow for cost recovery for the upgrade.

the current year. The imposition of local capacity requirements on load-serving entities (LSEs), initiated for 2007, will increasingly allow for multiple-year contracts for local reliability, but will not require them.

- A merchant facility that makes contributions to local reliability but is not absolutely necessary will likely desire to pass the upgrade costs on through its local reliability contract but may not be able to do so as such contracts are competitively awarded as these costs may be substantial and thus, render the plant non-competitive. In this case, the proposed rule runs the risk of encouraging the retirement of these facilities.

- Those merchant facilities that do not make a contribution to local reliability will only be able to pass through their costs of compliance, consistent with the provisions of AB 1576, which allows for costs of service contracts for coastal plants that repower to meet environmental performance standards, if they are successful in securing contracts solicited by the investor-owned utilities in response to resource adequacy requirements. At present, the utilities are required to contract with capacity equal to 90 percent of their expected summer peak load by September 30th of the previous year and 115 percent of their expected monthly peak at least 30 days prior to the start of the month. Again, substantial compliance costs would handicap plants in the competition for these contracts and encourage retirement.

Potential Reliability Impacts

Reductions in Available Capacity during Construction/Closure

Bringing down facilities/units in order to perform structural upgrades will reduce the amount of capacity available to meet demand. It is assumed that these upgrades can be performed at such times of the year and in a staggered fashion to as to minimize the impact of construction on system (and local) reliability. Whether such minimization is sufficient to maintain system reliability depends upon the amount of capacity that must be brought down at each site and the length of time that is must be off-line. Closing one unit at a time for several weeks will have a minimal impact on reliability. Closing a 1000 MW facility for a year will substantially reduce capacity available to meet peak demand during the summer.

Reductions in the Capacity of Facilities/Units that Continue to Operate during the Post-compliance Period

Certain structural and operational modifications undertaken to comply with the proposed rule may reduce unit capacity. The installation of dry cooling, for example has an impact upon a unit's maximum sustainable output. Owners may also choose to comply by reducing annual operations to stay below a capacity factor threshold.   These options reduce the potential revenue available to the owner as a result of reduced energy and/or capacity available to sell. This in turn will reduce the value of the plant and put additional pressure on the plant to retire.

Reductions in Capacity Due to Retirements
The most likely threat to reliability stems from the potential retirement of merchant facilities due to high compliance costs. The higher the costs, the greater the impact of compliance on the expected profitability of the facility/unit and the more likely an owner would be reticent to proceed without a long-term contract that guaranteed cost recovery. As the likelihood of obtaining such a contract may be influenced by compliance costs – the owner would consider these costs in constructing a bid to provide capacity to the CA ISO or an LSE for either local reliability or resource adequacy purposes. If compliance costs are high, this rule could encourage the retirement of units that are not necessary for local reliability or to meet resource adequacy requirements.

More Information is Needed
The above discussion indicates that much more information is needed before the potential impact of the proposed rule on costs and reliability can be more accurately assessed:

- Data on the relationship between water flow and generation is needed as the relationship between the two drives the extent to which changes in water flow necessarily affect generation. If substantial decreases in water flow can be realized at low costs without reducing generation, the impact of the proposed rule will be minimized.

- Estimates of the costs of the structural measures that are most likely to be used to comply with the rule are necessary to provide an estimate of the financial commitment involved. If these costs are relatively low (on a per kW basis), the rule will have a smaller impact on ratepayer costs and reliability. Should these costs be high, the possibility of retirements and the need for careful and well thought out timing of rule implementation is increased.

- An exact definition of the metric that will be used to calculate the capacity factor to be applied to each facility/unit *ex post* and going forward is needed (which determine the requirements to be imposed upon each facility/unit upon license renewal). This would allow for a more accurate assessment of the requirements that would be imposed on each facility/unit, as well as the flexibility they may have in complying with them.

- The range of implementation schedules that are being considered by the Board staff is of interest as substantial compliance costs may encourage retirements, thereby requiring an implementation schedule that contains enough lead time to allow owner/operators, load-serving entities, regulators, developers, *et al* enough time to adjust to the rule and its immediate consequences.

Informal Classification of OTC Plants

A discussion of the potential impacts of the proposed rule on reliability is assisted by classifying the plants in California that use once-through cooling according to the five relevant characteristics or services they provide to the system.

- Economic competitiveness

  A facility/unit that is efficient may to be able to absorb the costs of compliance without threat of retirement. On the other hand, the economic cost of reducing output to comply with the proposed rule is likely to be higher, leaving the cost of structural upgrades as the key determinant of the impact of the proposed rule. Among gas-fired plants, there is a strong correlation between competitiveness and age.

- (Specifically) needed for local reliability

  All facilities/units provide system and zonal reliability, their capacity contributing to the system-wide and zonal reserve margins needed to ensure meeting demand during peak hours. Facilities that are "specifically" needed are those whose immediate retirement would leave the control area operator unable to meet local reliability requirements. In several instances, local reliability requirements entail minimum levels of annual generation, perhaps foreclosing the option of reducing generation below threshold levels as a way to comply with the proposed rule. In Table 4 below, only those facilities with RMR contracts are considered to be needed for local reliability, those facilities without an RMR contract but in a local reliability area are noted accordingly.

- Units that operate below 15 percent Capacity Factor

  Facilities/units with a capacity factor of less than 15 percent would have a less stringent set of requirements to meet with respect to entrainment. Units that are economically competitive or are specifically needed for local reliability tend to have higher capacity factors.

  It should be noted that, while units needed for local reliability (and other units as well) may be projected to operate at less than a 15 percent capacity factor in the near term, their continued ability to do so may be based on the assumption that additional capacity will be added in the local area or that transmission upgrades will occur, reducing the need for energy from the unit. In the event that these do not take place or adverse conditions occur e.g., drought conditions, a prolonged outage of a large unit in the local area, frequent heat storms), it is conceivable and, in some cases likely that the unit would be required to operate at more than 15 percent. One need only look at the capacity factors during the 2000-1 energy crisis to see what might happen to capacity factors under "stress conditions."

Part III of this section, Table 5 and Appendix A provide more information on capacity factors relative to the 15 percent threshold for 2005 and for 2001 to 2005.

- Utility-owned vs. Merchant

  A utility can continue operating the facility/unit and pass the costs of compliance on to ratepayers. However, the additional cost of compliance may encourage the utility owner to reconsider the viability of continuing to operate the plant. A merchant generator may retire the facility/unit if unable to recover the costs (or merely expects that it is unlikely).

- Planned replacement/augmentation

  The Humboldt facility is expected to be replaced in 2010, substantially reducing the net benefits of structural upgrades (if required) in the interim. Other facilities, currently needed for local reliability, may also operate at lower capacity factors in the future due to new generation and/or transmission upgrades coming online.

Table 4
Classification Factors of Once-Through Cooled Plants in California

Plant Name	Competitive	Needed for Local Reliability	> 15% CF expected	Utility-owned	Planned Replacement
Alamitos		Partly			
Contra Costa		Partly			
Diablo Canyon	Yes		Yes	Yes	
El Segundo		In LRA			
Encina		Specifically	Yes		Yes
Harbor	Yes	N/A	Yes	Yes	
Haynes	CC portion	N/A	Yes	Yes	Long run
Humboldt		Specifically	Yes	Yes	Yes
Huntington Beach	New units	In LRA			
Mandalay					
Morro Bay					
Moss Landing CC	Yes		Yes		
Moss Landing ST					
Ormond Beach					
Pittsburg		Partly			
Potrero		Specifically			Yes
Redondo Beach		In LRA			
San Onofre	Yes	In LRA	Yes	Yes	
Scattergood	Sort of	N/A	Yes	Yes	Long run
South Bay		Specifically	Yes		Yes

Summary of Available Information on Costs for Alternative Cooling Systems

Through the six siting cases at the Energy Commission involving once-through cooling, Energy Commission staff and its consultants have done a great deal of work investigating alternative cooling systems that can be used at coastal power plant sites. The Energy Commission's PIER Program is conducting ongoing research into engineering and operational issues associated with air cooling, hybrid wet-dry cooling, and salt water closed loop towers. Retrofitting and repowering are defined as follows:

- Retrofitting Cooling Systems – Retain the current generating technology (steam boiler or combined cycle) and switch to an alternative method of cooling such as closed loop towers or air cooling.

- Repowering or Replacing Power Plants – Completely remove the existing generating system and replace with combined cycle or single cycle combustion turbine (peaker) generating technology. Once-through, closed loop towers or air cooling systems may be used.

The costs of retrofitting coastal power plants vary widely and are difficult to estimate. Although extensive information is available on cost and performance issues associated with investigating alternative cooling systems and water supplies for new power plants or repowering, [6] little information is available on retrofitting alternative cooling systems on existing steam units that have low capacity factors and may have site constraints. Other than the Pittsburg Power Plant Unit 7 conversion cited in the US EPA background report for the Phase II Rule ($54 / kW in 1999$ totaling $40 million for a 751 MW unit), we are not aware of any case study information on cooling system retrofit costs on the West Coast.

Retrofitting to either wet or dry cooling includes several cost and site variables that should be carefully considered. Important cost variables include replacement power costs for use/redirection of existing power to operate wet or dry cooling equipment; capital costs to acquire and install wet or dry cooling equipment; and fresh or reclaimed water source costs (and availability) for wet cooling operation. Important site variables and potential costs include the availability of on-site space, or the need to acquire additional coastal land (if available), to accommodate wet or dry cooling equipment. Other cost and economic viability considerations important to consider include the facility type, age, size, expected capacity factors, and efficiency of the coastal power plants. These variables make it difficult to make general conclusions on the cost or viability of cooling system retrofits for existing units without both an extensive site and plant operation specific analysis.

[6] See Chapter 6 of Issues and Environmental Impacts Associated with Once-Through Cooling …

PART III – COMMENTS, QUESTIONS AND RECOMMENDATIONS ON THE PROPOSED REGULATORY CHANGES

Scope of CEQA Review
The Energy Commission recommends that the potential effects of the proposed 316(b) policy on the reliability and resource adequacy of the state's electricity supply be evaluated in the State Water Board's functional equivalent document. The Energy Commission offers to work with State Water Board during the review process to ensure that this issue is sufficiently addressed.

Critical Information Needed to Complete the CEQA Review
Two important sets of data are needed for an analysis of the potential effects of the proposed rule on electricity supply resources: historic sea water flow data through the cooling system intakes; and compliance cost estimates and cooling retrofit cost estimates. Without this data, neither Energy Commission staff nor Water Board staff can assess possible effects on generation, compliance costs, or the range of options available to generators to meet the performance standards. As will be discussed further, the lack of flow data also does not allow the efficacy of the proposed rule to be determined, especially for power plants operating below the 15 percent annual capacity factor levels.

The issue of economic feasibility for compliance with the proposed rule is an important policy consideration that should be examined in the CEQA document. Examples of how this concept has been utilized in other programs are provided in this letter.

Possible variations in capacity factor levels are another piece of information needed for the analysis. Because many of the coastal plants operate as important peak and load following units during periods of peak summer demand, their capacity factors do not change linearly over time. Rather, they change in direct response to marginal conditions such as temperature effects on demand, economic growth, trends in additions of competing generation resources, and local area reliability requirements (which are affected by transmission conditions).

Implementation
Item 7 in the proposed Power Plant Cooling Water Intake Provisions states that:

> "The Regional Water Boards shall implement this policy when a permit for an existing power plant is first reissued after [the effective date of the policy] or when the permit is reopened, whichever occurs first."

From this language, it is not clear exactly when generators would need to comply with the rule. Nor is it clear how much time generators would have to implement required changes in operations or infrastructure in order to comply with the rule.

From discussions with State Water Board staff, it appears that the Regional Water Boards will have wide discretion in interpreting when the proposed policy would be applied to each National Pollution Discharge Elimination System

(NPDES) permit, and how long each permit holder would have to comply with the new rule and enact operational or physical changes.

One of the Energy Commission's primary concerns is that generators, load serving entities[7] (LSEs), energy regulators and the market be given sufficient time to plan for and comply with the proposed policy. Total lead time for constructing new generating facilities ranges from 60 to 78 months: 24 months for utility procurement, Request for Offers (RFO) for new generating capacity and contract negotiation; 6 to 12 months to prepare an Application for Certification, 12 months for CEQA review, and 18 to 30 months for construction. Lead time for cooling system retrofits is unknown, but would presumably be much less.

The Energy Commission recommends that the CEQA document specify and assess:

- The expiration dates for each NPDES permit
- Guidance on implementation and compliance schedules
- Possible ramifications on electric system reliability for earlier rather than later implementation periods including what longer-term mitigation options are precluded by shorter-term implementation schedules and what the incremental cost could be
- Guidance for NPDES permits that have not been systematically reviewed by the Regional Water Boards[8]
- The timing needed to address stressed power system conditions under which higher than expected cooling flows may nevertheless be allowed. For example: the salmon protection restrictions for hydroelectric production were waived in the Pacific Northwest during the July 2006 heat storm.

Calculation Baseline for Intake Flows

Item 2(e) in the proposed Power Plant Cooling Water Intake Provisions states that:

> "The calculation baseline shall be determined using actual flow rates calculated as a mean of the flow rates provided to the Regional Water Board in monitoring reports over the last NPDES cycle."

This is a significant definitional change to the calculation baseline. The coastal power plants were designed and permitted to operate as baseload facilities. Most of the coastal plants now operate at low to moderate capacity factors. Therefore, retaining the baseline definition at permitted flow levels, rather than actual flow levels, as proposed, would allow nearly all coastal generators to comply with the new 316(b) rule without having to make any operational or structural changes.

The Energy Commission does not have a table of permit expiration dates nor data on flow levels. It is recommended that both be included in the CEQA review

[7] Load serving entities or LSEs are the utilities and companies supplying electricity to customers.
[8] From discussions with State Water Board staff, Energy Commission staff learned that not all NPDES are reviewed and renewed during the standard 5-year cycle.

and provided to agencies such as the Energy Commission as soon as possible so that we can begin our own analyses.

If some plants can use the 2000-2001 Energy Crisis period in their baseline calculation and others use more recent years, an inequity is created and may also have potential negative power system impacts. Plants with higher baselines would have more latitude to meet performance standard reduction requirements than plants with lower baselines. Appendix A provides a summary of power plant operations and capacity factors from 2001 to 2005. An important parameter is their operation, however limited in duration, during critical energy demand periods which include peak summer months as well as during times of significant generation or transmission outages.

The State Water Board should consider establishing a uniform 5-year period for calculating baseline flows and then analyze the potential results in the CEQA document. Because a number of these units operate as marginal units their operation can vary significantly during the year and from year to year.

There are two additional dimensions to the baseline issue that can be considered, 1) over what historical time period should past performance influence the calculation of the baseline, and 2) what metric should be used in the calculation. As was done to calculate the initial nitrogen oxide (NOx) emission allocations by the South Coast Air Quality Management District (SCAQMD) for rule 1135/RECLAIM, the “baseline” flow on which reductions are calculated could be calculated under likely capacity factors (CFs)/flows during stressed system conditions. Under stressed conditions, the plant/unit CFs/flows are higher than unstressed. Presumably, flows are also higher. So 60 percent of a higher number will mean they are permitted to have higher flows than otherwise. But, this flexibility under stressed conditions may be necessary for power system reliability (and may appear anyway in the form of cooling limit waivers when stressed conditions appear.) If this approach is taken, then under normal “expected” conditions, flows are likely to be significantly lower (assuming there is no other incentive to keep flows elevated in normal conditions.)

Unit versus Plant-Level Calculations on Baseline Flows:
While there are 21 large coastal plants subject to the proposed rule, many plants have more than one cooling intake structure. Nearly all of the power plants have multiple generating units, and larger complexes can have 5 or 6 operational units. There are about 70 operational units in the coastal fleet, which does not include the single cycle gas-fired peaker units. (See Appendix A.) The number of intakes at each power plant complex and the relationship between intakes and various generating units is unknown and should be made available during the CEQA review process. More precision is gained by focusing at the intake-level and unit-level, rather than the plant level. This approach may also enable the State Board to develop a policy that will allow plant operators the necessary flexibility to dispatch specific units as needed, to meet electricity reliability and resource adequacy needs.

Performance Standard Methodological Issues
Part 2(b) of the proposed Power Plant Cooling Water Intake Provisions provides the performance standards recommended by State Water Board staff. In essence, the proposed rule would require all power plants operating at 15 percent or greater capacity factors (based on a five-year average) to reduce entrainment by 90 percent from the calculation baseline, 60 percent of which must be actual reductions from operational or infrastructure changes. Off-site mitigation could be used for the remaining 30 percent reduction obligation. Nuclear facilities may be allowed to use off-site mitigation as the best technology available if safety issues are raised by the Nuclear Regulatory Commission.

The Energy Commission offers several observations and clarifying questions on the data and methods used in developing the performance standard recommendations.

Non-Correlation of Intake Flows and Electricity Generation: Lack of Critical Data
Part 2(b)(ii) of the proposed rule would apply the entrainment reduction requirements to plants operating at a capacity utilization rate (five-year average capacity factor) of 15 percent and above. There is not sufficient data to calculate the correlation between water flows through the intake structures and power generation. Many plants appear to pump water when not generating electricity, or to run pumps at high levels when operating at low levels. While the goal of the rule is to reduce flows by 60 percent for thermal plants operating above 15 percent, it cannot be determined how much plants would have to reduce generation to reach the 60 percent target.

Five-Years versus One-Year for Calculating the 15 Percent Capacity Factor Threshold
Part 2(b)(ii) of the proposed rule specifies that:

> "If the power plant has a capacity utilization rate of 15 percent or greater, reduce entrainment of all life stages of fish and shellfish by 90 percent of the calculated baseline by any combination of operational or structural control."

The definitions refer readers to 40 C.F.R. 125.93 for the definition of capacity utilization rate, which states:

> "The average annual net generation should be measured over a five-year period (if available) of representative operating conditions, unless the facility makes a binding commitment to maintain the capacity utilization rate below 15 percent for the life of the permit…"

Based on the information in Table 5, six of the 21 coastal plants would not be affected by the entrainment provisions of the proposed rule (two nuclear facilities, two facilities that have shut down, and two that have announced plans to replace old facilities with modern technology not using once-through cooling). For the remaining 15 power plants, their five-year average capacity factors for 2001-2005 range from 19 to 35 percent. However, the one-year average capacity factors for 2005 are much lower, and range from 3 to 26 percent. Ten plants ran below 15 percent in 2005. As shown in Appendix A, this shift is due to the fact that the steam plants ran at higher capacity factors in the 2001-2002 period than in the following years. As with the calculation assumption for baseline flows, selection of the five-year period will affect how many plants are subject to the 15 percent exemption threshold. The five-year average for the 2002-2006 period will yield different results for how many coastal plants ran above and below the 15 percent capacity factor threshold.

The language in the proposed rule is not precise on whether the five-year or one-year calculation is proposed, and the regulatory definition in 40 C.F.R. 125.93 implies that the State Water Board may have some discretion in how to determine the time period.

The information in Table 5 indicates that 10 plants in 2005 ran below 15 percent capacity factors and could choose a compliance option of maintaining that level of operation through a "binding commitment." This may prove to be an attractive compliance option for some coastal power plant generators. For the plants holding RMR contracts from the CAISO that seek to maintain operations below 15 percent as a compliance option, it may be appropriate to craft some emergency flexibility provisions in case the CAISO dispatches the units and pushes them above 15 percent in order to maintain system or local reliability.

The US EPA's reasoning for creating this exemption is that plants operating below 15 percent annual capacity factors tend to be peakers, draw less water and cause substantially less impact than baseload facilities, and would face higher compliance costs on a per megawatt (MW) and megawatt-hour (MWh) basis than baseload plants.[9]

While there is logic in this approach, it is not clear that these assumptions are appropriate for California's power plants. The coastal plants in California that operate at low production levels are the older, less efficient steam boiler plants that were historically designed and operated as baseload facilities, but that are now used for important summer peaking, load following and ancillary services such as voltage support and spinning reserves. While operating at far lower levels than baseload plants, many of these facilities appear to operate their cooling pumps when the plants are not being dispatched for a number of reasons. This calls into question US EPA's key assumption on proportionate impact for California's older coastal units. As discussed earlier, operation of the intake pumps when plants are not generating electricity for sale may be creating additional impacts.

[9] 69 FR at 41616. "EPA has identified peaking facilities in the final Phase II rule as those facilities that operate at an overall capacity of less than 15 percent. EPA believes that facilities operating below 15% should be subject to less stringent compliance requirements relative to a typical base load facility. The threshold of 15% is based on these facilities' reduced operating levels, low potential for entrainment impacts, and consideration of economic practicability (*see*, 67 FR 17141)."

The 15 percent capacity factor threshold may not provide the appropriate criteria to identify plants with low flows, especially the older plant complexes with multiple units. Plants such as these operating below 15 percent could be pumping more total water than plants or units operating above 15 percent; and the rule would not compel the < 15 percent plants to make any reductions to meet the entrainment performance standards. For example, a modern combined cycle plant with 2 large units operating above 15 percent may use less total water than an older plant with 5 or 6 units that runs its pumps even when not generating electricity. The modern units would be required to reduce flows by 60 percent, but the older plant would not be required to reduce flows.

Because the 15 percent threshold was introduced by US EPA as a cost containment measure, it may be appropriate to consider the cost-effectiveness of reducing entrainment impacts, not simply reducing entrainment impacts without regard to cost. If the goal is to cost-effectively reduce flows and the total volume of water moving through the intakes and pumps in order to reduce entrainment impacts, it is important to have the flow data to determine that the proposed rule is creating the environmental benefits intended by the rule change. Rather than using the 15 percent cut-off established by the federal rule, another option could be to develop a direct compliance cost threshold similar to how the best available retrofit control technology (BARCT) cost effectiveness tests were used to establish unit-specific BARCT and then initial NOx allocations for Rule 1135 by SCAQMD. A more appropriate peaker plant operational threshold might also require the availability of sea water intake flow data.

In addition, it is also important to understand that a low threshold like 15 percent may mean that plants that operate just above this threshold may not have either the financial incentive or wherewithal, given their low capacity factors, to spend the money to comply with the new rule. At this time, the timing and magnitude of the loss of any generating capacity raises potential system reliability issues.

On an hourly basis, 15 percent is equivalent to 1,314 hours of operation (out of 8,760 hours a year). The contribution of the potentially affected plants to the power system can be significant at EVERY hour of the year in certain locations and system conditions. Voltage must be supported and frequency regulated every second of the year, and some of these plants contribute those services to the system.

Table 5
State Water Board 316(b) Proposed Rule and California's Coastal Power Plants
California Energy Commission – September, 2006

Power Plants Exempted from Compliance with Proposed Rule		**2006 Dependable Capacity (MW)**	**RMR Contract 2006 (MW)**	**2001 – 2005 Average Capacity Factor (%)**	**2005 Capacity Factor (%)**	**Notes**
Nuclear	Diablo Canyon	2195		85-93	85-93	Nuclear plants may be exempted from operational changes due to safety concerns, but must comply via off-site mitigation
	San Onofre	2167		85-93	85-93	
Sub-Totals	***2***	***4,362***				
Shut Down	Hunters Point	0				
	Long Beach	0				
Sub-Totals	***2***					
Repower Without OTC	Humboldt	105	106	45.9	46.7	CF>15%, but will repower without once-through cooling
	South Bay	703	702	27.4	24.9	
Sub-Totals	***2***	***808***	***808***			
Total Exempted Plants	***6***	***5,170***	***808***			
Plants with 2001-2005 Average Capacity Factor Greater than 15% Subject to Proposed Rule						
	Alamitos	1950	320	24.2	7.7	
	Contra Costa	680	337	24.0	5.6	May change cooling tech.
	El Segundo	670		24.8	11.3	
	Encina	929	960	34.8	22.9	Will add 400 MW peaker
	Harbor	240		22.4	13.8	CF for Combined Cycle only
	Haynes	1611		26.0	26.8	New Combined Cycle
	Huntington Beach	880	430	24.2	20.2	Newly refurbished steam boilers
	Mandaly	560		20.3	7.1	
	Morro Bay	676		19.7	5.4	
	Moss Landing	2538		28.2	22.0	Combined cycle 2005 CF = 48%
	Ormand Beach	1500		20.2	4.0	
	Pittsburg	1370	629	28.0	5.4	
	Potrero	363	362	25.3	13.5	Repower proceeding terminated
	Redondo Beach	1310		19.2	3.7	
	Scattergood	803		23.9	16.2	
Sub-Totals	***15***	***16,080***	***3,038***			
Totals	**21**	**21,250**	**3,846**			
Plants with 2005 Capacity Factors Less than 15%	10	9,319	1,648			

Reducing Intake Flows during Periods of Non-Operation
Item 2(d) in the proposed Power Plant Cooling Water Intake Provisions states that:

> "If electrical energy will not be produced for a period of two or more consecutive days, the owner or operator must minimize entrainment by reducing intake flow to ten percent of the baseline flow rate…"

Based on discussions with State Water Board staff, the intent of this provision is to reduce the volumes of sea water drawn through the intakes during periods of non-operation. The Energy Commission supports the goal of reducing entrainment impacts when the pumps are used during periods of non-operation. However, not producing energy is not a condition of "non-operation." Flows are required for the plant to provide critical power system services other than producing energy.

For example:

- Spinning or other reserves, market power mitigation, voltage support, frequency regulations, etc., require cooling.
- Plants may generate electricity for internal operational purposes without selling to the grid.
- One or more units may be run at a low but continuous or near-continuous level in order to maintain the plant's ability to ramp up quickly to meet load requirements.

These non-energy production operations need to be considered in this section of the regulation. A unit-level review of the plants should be conducted to determine their levels and periods of operation. State Water Board staff may then wish to modify the language of this section in order to achieve the desired intent.

Requirement to Investigate Alternative Water Supplies
Item 3 in the proposed Power Plant Cooling Water Intake Provisions states that:

> "Owners or operators of power plants must consider the use of treated wastewater as a cooling medium when co-located in close proximity to a publicly-owned treatment works."

We note that this provision has no clearly defined standard or burden of proof nor any provision for a Regional Water Board or owner / operator to use or act upon the results of the "consideration." State Water Board staff may want to further develop this section if the intent is to do more than identify potentially available alternative water supply sources in the general vicinity of coastal plants using once-through cooling.

Energy Commission staff routinely investigates all potentially feasible cooling alternatives for coastal plants seeking to repower but proposing to continue using once-through cooling. The same is true when inland plant developers propose to use inland surface waters for cooling. Moreover, Energy Commission staff has also investigated the feasibility of using air cooling systems at many coastal and inland plants. This alternatives analysis is required under CEQA. The Ocean Protection Council's coastal plant retrofit feasibility study will include an assessment of available recycled or reclaimed water sources on a plant by plant basis.

Requirement to Consider Endangered Species

Part H of the background document provides a discussion of endangered species entrainment and impingement, but there is no corollary section in the Power Plant Cooling Water Intake Provisions. State Water Board staff stated that this was an oversight at the July 31 workshop. As with the above discussion on alternative water supplies, there will need to be specific requirements for the provision to have a material effect on reducing the effects of once-through cooling systems on listed species.

Cumulative Effects Study

Item 2(g) in the proposed Power Plant Cooling Water Intake Provisions states that:

> "Owners or operators of power plants with overlapping intake water source areas must conduct a cumulative ecological study. Owners or operators of power plants located in the jurisdictions of different Regional Water Boards with overlapping intake water sources areas must also conduct a cumulative ecological study."

The Energy Commission believes it is appropriate to conduct cumulative impact studies. As a Condition of Certification for the Huntington Beach Power Plant Units 3 and 4 Retool Project, CEC required the applicant to conduct a cumulative analysis study. Also the PIER Environmental Area program at the Energy Commission is working to fund grant proposals that would review the existing analyses of the cumulative impacts of once-through cooling and make recommendations about how to conduct such an analysis for California's coastal facilities.

Use of Restoration as a Best Technology Available (BTA) Compliance Option

Item 2(b) in the proposed Power Plant Cooling Water Intake Provisions allows for the use of restoration as a best technology available compliance option for thermal and nuclear facilities – up to 30 percent for thermal plants and 100 percent for nuclear facilities. Item 2(h) specifies where such restoration measures can be implemented.

While impact reduction from changes in physical structures, operations or cooling systems is generally preferable, the Energy Commission has approved the use of habitat restoration as a BTA and mitigation option. In Southern California, habitat restoration (especially wetland restoration) has been used successfully to mitigate impacts from various sources. Restoration can have direct benefits on impacted species as well as indirect benefits to the ecosystem as a whole. The restoration provisions for Elkhorn Slough in the Moss Landing mitigation requirements are a good example of ecosystem level benefits.

The Energy Commission raises for the State Water Board's consideration several questions and comments on how the restoration BTA option is specified in the proposed rule:

1. Biological resource mitigation and wetlands restoration projects require long-term scientific monitoring (success monitoring) to demonstrate that they are successfully replacing the ecological functions damaged or destroyed by development projects. Success monitoring and adaptive management requirements should be considered by the State Water Board in its guidance to the Regional Boards for restoration projects in order to ensure their long-term success; and

2. Mitigation ratios should also be evaluated and specified. A one-to-one ratio may be appropriate given the assumptions used in the Habitat Production Foregone models. However, higher compensation ratios may be more appropriate in some circumstances.

Use of Habitat Foregone Methodology

Item 2(i) in the proposed Power Plant Cooling Water Intake Provisions states that:

> "When designing a restoration program the methodology used to assess the area to be restored shall be 'habitat production foregone'".

The Energy Commission has used empirical transport models (ETM) which estimate the percent of larvae at risk that would be killed due to entrainment (proportional mortality) and the area of the population at risk (source water body). ETM estimates yield the proportional loss and the source water body, the product which is an estimate of the area of habitat required to produce the larvae lost due to entrainment (habitat production foregone (HPF)). ETM models translate the larval losses into ecosystem losses, therefore, the larvae analyzed in the models encompass the various life histories of the organisms entrained, thus acting as proxies for the whole. Other models (adult equivalent models and fecundity hindcast) used in impact analyses translate larval losses into adults. These models have been hampered by the need for species-specific life history information that is often lacking for many species entrained in California. The results from these models are also very specific, whereas the results from ETM are not. Therefore, calculations based on habitat production foregone encompass ecosystem losses, not species-specific losses.

Reference Stations

Item 5 in the proposed Power Plant Cooling Water Intake Provisions states that:

"Reference stations may be used to identify baseline marine life conditions for the same habitat as the power plant, if determined by the Expert Review Panel."

The applicability of reference stations is unclear. This provision, as written, is ambiguous and it is uncertain as to how reference stations will be used. Greater understanding is needed to determine how they will be used and where they will be located.

Definition of New Power Plant
The proposed rule modifies the EPA definition of a new power plant to incorporate some elements of the Phase I definition:

a) "any power plant which commenced construction after Jan 17, 2002, or

b) any power plant that was in operation prior to Jan 17, 2002, but as of the effective date of the policy, has undergone or will undergo a major modification. A major modification is a modification of the facility that increases electrical production capacity and increases the intake flow rate."

The intent of the definitional change is to address replacement projects where entire generating units are torn down and replaced with completely new generating units using different generating technologies, but where the plant continues to use the existing once-through cooling system, even if it requires major modifications. The wording may not achieve the desired objective of reducing the continued use of once-through cooling when new generating units are constructed at existing coastal power plants. First, because combined cycle units use water more efficiently on a per-MWh output basis than a steam boiler unit, it is unlikely that replacement projects would increase their intake flow levels and meet the criteria in part (b). Second, in the Energy Commission's experience, the standard of an increase or net increase in generating capacity is an imperfect test; some major repowering/replacement projects have increased net capacity just below the 50 MW threshold that triggers the Energy Commission's licensing authority. If State Water Board staff is seeking to discourage the use of once-through cooling in replacement projects, the definition will need to be modified. Whatever definition is adopted the Energy Commission believes that the definition should be crafted to apply to all facility modifications, and not just those subject to Energy Commission jurisdiction.

APPENDIX A
2001-2005 Capacity Factors

Generation and Capacity Factors for Natural Gas-Fired Power Plants in California Using Once-Through Cooling: 2001 - 2005

Notes

Does not include San Onofre and Diablo Canyon (4200+ MW at 85-93% capacity factor)
Source: Energy Commissin Electricity Analysis Office, David Vidaver, 7/14/2006 (654-4656)
Capacity Factor: Output/Possible Output, where Possible Output is Capacity*8760 hrs
Technology: ST = Steam Boiler, CC = Combined Cycle, CT = Combustine Turbine Peaker

Plant	Unit	Capacity	Technology	On-Line Date	2001 MWh	2001 CF	2002 MWh	2002 CF	2003 MWh	2003 CF	2004 MWh	2004 CF	2005 MWh	2005 CF	2001-2005 CF
Alamitos	1	175	ST	1956	150,610	9.8%	142,973	9.3%	123,589	8.1%	99,187	6.5%	41,526	2.7%	7.3%
Alamitos	2	175	ST	1957	314,010	20.5%	167,808	10.9%	129,675	8.5%	105,300	6.9%	32,665	2.1%	9.8%
Alamitos	3	320	ST	1961	1,300,483	46.4%	1,043,989	37.2%	1,089,514	38.9%	703,320	25.0%	260,716	9.3%	31.4%
Alamitos	4	320	ST	1962	1,326,102	47.3%	710,764	25.4%	622,817	22.2%	574,893	20.5%	155,027	5.5%	24.2%
Alamitos	5	480	ST	1969	2,821,879	67.1%	1,433,863	34.1%	861,684	20.5%	1,075,935	25.5%	393,998	9.3%	31.3%
Alamitos	6	480	ST	1966	2,682,933	63.8%	619,790	14.7%	784,026	18.6%	460,492	10.9%	427,180	10.1%	23.6%
Alamitos	**1-6**	**1,950**			**8,596,017**	**50.3%**	**4,119,187**	**24.1%**	**3,611,305**	**21.1%**	**3,019,127**	**17.7%**	**1,311,112**	**7.7%**	**24.2%**
note: Alamitos 7 (133 MW CT) is retired															
Contra Costa	6	340	ST	1964	1,893,584	63.6%	876,534	29.4%	62,809	2.1%	138,181	4.6%	34,088	1.1%	20.2%
Contra Costa	7	340	ST	1964	1,530,961	51.4%	1,148,685	38.6%	510,893	17.2%	672,563	22.5%	296,949	9.9%	27.9%
Contra Costa	**6-7**	**680**			**3,424,545**	**57.5%**	**2,025,218**	**34.0%**	**573,702**	**9.6%**	**810,744**	**13.6%**	**331,037**	**5.6%**	**24.0%**
note: Contra Costa 1-3 (348 MW total) are retired; units 4-5 (232 MW total) are synchronous condensers; unit 8 (530 MW) is in permitting															
El Segundo	3	335	ST	1964	711,903	24.3%	1,061,387	36.2%	710,468	24.2%	270,756	9.2%	366,353	12.4%	21.3%
El Segundo	4	335	ST	1965	1,681,052	57.3%	1,340,186	45.7%	601,024	20.5%	244,649	8.3%	297,908	10.1%	28.4%
El Segundo	**3-4**	**670**			**2,392,955**	**40.8%**	**2,401,573**	**40.9%**	**1,311,492**	**22.3%**	**515,405**	**8.8%**	**664,261**	**11.3%**	**24.8%**
note: El Segundo 1-2 (350 MW total) are retired															
Encina	1	107	ST	1954	352,670	37.6%	145,804	15.6%	116,765	12.5%	175,749	18.7%	146,205	15.6%	20.0%
Encina	2	104	ST	1956	372,258	40.9%	181,603	19.9%	148,499	16.3%	227,419	24.9%	157,440	17.2%	23.9%
Encina	3	110	ST	1958	460,636	47.8%	187,082	19.4%	209,592	21.8%	393,661	40.7%	179,890	18.6%	29.7%
Encina	4	293	ST	1973	1,565,982	61.0%	906,659	35.3%	940,196	36.6%	1,218,282	47.3%	806,465	31.3%	42.3%
Encina	5	315	ST	1978	1,240,155	44.9%	1,028,439	37.3%	1,150,690	41.7%	1,295,399	46.8%	575,978	20.8%	38.3%
Encina	**1-5**	**929**			**3,991,700**	**49.0%**	**2,449,586**	**30.1%**	**2,565,741**	**31.5%**	**3,310,510**	**40.7%**	**1,865,978**	**22.9%**	**34.8%**
does not include Encina GT (16 MW GT), which operates at a very low capacity factor (<3%)															
Harbor CC	10A-10I	240	CC	1994	621,309	29.6%	620,743	29.5%	500,569	23.8%	326,865	15.5%	290,661	13.8%	22.4%
note: does not include Harbor 10-14 (250 MW total) CTs (operational) or Harbor 1-4 (retired GTs, 76 MW total)															
Haynes	1	200	ST	1962	349,335	19.9%	464,303	26.5%	630,867	36.0%	613,466	34.9%	447,283	25.5%	28.6%
Haynes	2	200	ST	1963	948,056	54.1%	592,743	33.8%	455,385	26.0%	623,023	35.5%	374,858	21.3%	34.2%
Haynes	5	318	ST		1,105,944	39.7%	482,911	17.3%	1,051,743	37.8%	352,160	12.6%	520,463	18.6%	25.2%
Haynes	6	318	ST		383,648	13.8%	581,254	20.9%	323,992	11.6%	382,120	13.7%	83,943	3.0%	12.6%
Haynes ST	**1,2,5,6**	**1,036**			**2,786,983**	**30.7%**	**2,121,211**	**23.4%**	**2,461,987**	**27.1%**	**1,970,769**	**21.7%**	**1,426,547**	**15.7%**	**23.7%**
Haynes	9	288	CC	2005									1,190,416	47.1%	47.1%
Haynes	10	288	CC	2005									1,171,991	46.4%	46.4%
Haynes CC	**9-10**	**575**											**2,362,407**	**46.9%**	**46.9%**
Haynes	**All**	**1,036/1,211**			**2,786,983**	**19.7%**	**2,121,211**	**15.0%**	**2,461,987**	**17.4%**	**1,970,769**	**14.0%**	**3,788,954**	**26.8%**	**26.0%**
note: does not include Haynes 3-4 (444 MW total), retired															

Humboldt Bay	1	52	ST	1656	301,752	66.2%	194,615	42.7%	135,796	29.8%	190,914	41.8%	216,451	47.4%	45.6%
Humboldt Bay	2	53	ST	1958	378,430	81.5%	190,383	41.0%	95,965	20.7%	192,851	41.4%	212,662	45.7%	46.1%
Humboldt Bay	**1-2**	**105**			**680,182**	**73.9%**	**384,998**	**41.9%**	**231,761**	**25.2%**	**383,765**	**41.7%**	**429,113**	**46.7%**	**45.9%**
Huntington Beach	1	215	ST	1958	688,888	36.6%	647,852	34.4%	703,212	37.3%	716,090	37.9%	489,439	25.9%	34.4%
Huntington Beach	2	215	ST	1958	698,501	37.1%	699,436	37.1%	712,307	37.8%	756,114	40.0%	415,798	22.0%	34.8%
Huntingon Beach	**1-2**	**430**			**1,387,389**	**36.8%**	**1,347,288**	**35.8%**	**1,415,519**	**37.6%**	**1,472,204**	**39.1%**	**905,237**	**24.0%**	**34.6%**
Huntington Beach	3	225	ST	2002			55,128	2.8%	162,719	8.3%	370,597	18.8%	379,530	19.3%	15.4%
Huntington Beach	4	225	ST	2003					142,146	7.2%	346,216	17.5%	269,634	13.6%	15.6%
Huntington Beach	**3-4**	**450**					**55,128**	**2.8%**	**304,865**	**7.7%**	**716,813**	**18.2%**	**649,164**	**16.5%**	**17.3%**
Huntington Beach	**1-4**	**880**									**2,189,017**	**28.4%**	**1,554,401**	**20.2%**	**24.2%**
Mandalay	1	215	ST	1959	1,066,366	56.6%	499,331	26.5%	288,357	15.3%	314,217	16.6%	137,567	7.3%	24.5%
Mandalay	2	215	ST	1959	1,077,388	57.2%	564,964	30.0%	365,833	19.4%	404,936	21.4%	211,460	11.2%	27.9%
Mandalay	3	130	CT	1970	36,764	3.2%	8,386	0.7%	9,120	0.8%	0	0.0%	1,505	0.1%	1.0%
Mandalay	**1-3**	**560**			**2,180,518**	**44.4%**	**1,072,681**	**21.9%**	**663,310**	**13.5%**	**719,153**	**14.7%**	**350,532**	**7.1%**	**20.3%**
Morro Bay	3	338	ST	1962	1,840,033	62.1%	503,361	17.0%	146,009	4.9%	232,091	7.8%	166,175	5.6%	19.5%
Morro Bay	4	338	ST	1963	1,544,763	52.2%	1,000,637	33.8%	145,630	4.9%	114,016	3.8%	153,085	5.2%	20.0%
Morro Bay	**3-4**	**676**			**3,384,795**	**57.2%**	**1,503,997**	**25.4%**	**291,639**	**4.9%**	**346,107**	**5.8%**	**319,260**	**5.4%**	**19.7%**
note: does not include Morro Bay 3-4 (326 MW total), retired															
Moss Landing	1	265	CC	2002			493,343	21.3%	914,952	39.4%	720,204	31.0%	1,128,770	48.6%	35.1%
Moss Landing	2	265	CC	2002			475,206	20.5%	947,231	40.8%	843,722	36.3%	1,026,569	44.2%	35.4%
Moss Landing	3	265	CC	2002			404,597	17.4%	835,759	36.0%	892,294	38.4%	1,135,285	48.9%	35.2%
Moss Landing	4	265	CC	2002			410,285	17.7%	828,009	35.7%	927,815	40.0%	1,131,380	48.7%	35.5%
Moss Landing	6	739	ST	1967	3,627,486	56.0%	2,276,079	35.2%	580,790	9.0%	363,877	5.6%	235,205	3.6%	21.9%
Moss Landing	7	739	ST	1968	5,017,197	77.5%	1,730,249	26.7%	752,808	11.6%	765,596	11.8%	231,933	3.6%	26.2%
Moss Landing	**1-7**	**2,538**			**8,644,683**	**38.9%**	**5,789,759**	**26.0%**	**4,859,549**	**21.9%**	**4,513,508**	**20.3%**	**4,889,142**	**22.0%**	**28.2%**
Ormond Beach	1	750	ST	1971	3,109,591	47.3%	1,189,349	18.1%	759,186	11.6%	1,355,431	20.6%	133,615	2.0%	19.9%
Ormond Beach	2	750	ST	1973	3,026,036	46.1%	1,210,342	18.4%	1,125,014	17.1%	966,810	14.7%	391,101	5.9%	20.4%
Ormond Beach	**1-2**	**1,500**			**6,135,627**	**46.7%**	**2,399,691**	**18.3%**	**1,884,200**	**14.3%**	**2,322,241**	**17.7%**	**524,716**	**4.0%**	**20.2%**
Pittsburg	5	325	ST	1960	1,596,868	56.1%	547,082	19.2%	785,460	27.6%	693,603	24.3%	341,666	12.0%	27.8%
Pittsburg	6	325	ST	1961	1,818,227	63.9%	703,877	24.7%	209,148	7.3%	596,613	20.9%	202,408	7.1%	24.8%
Pittsburg	7	720	ST	1972	4,715,572	74.8%	2,760,981	43.8%	1,127,364	17.9%	622,181	9.8%	108,788	1.7%	29.6%
Pittsburg	**5-7**	**1,370**			**8,130,667**	**67.7%**	**4,011,939**	**33.4%**	**2,121,972**	**17.7%**	**1,912,396**	**15.9%**	**652,862**	**5.4%**	**28.0%**
note: does not include Pittsburg 1-4 (652 MW total), retired															

Potrero	3	207	ST	1956	1,048,178	57.8%	570,643	31.5%	851,453	47.0%	872,320	48.0%	385,621	21.2%	41.1%
Potrero	4	52	CT	1976	29,894	6.6%	9,880	2.2%	18,319	4.0%	16,480	3.6%	17,776	3.9%	4.1%
Potrero	5	52	CT	1976	52,880	11.6%	9,691	2.1%	11,159	2.4%	15,815	3.5%	14,881	3.3%	4.6%
Potrero	6	52	CT	1976	50,306	11.0%	8,185	1.8%	10,426	2.3%	15,343	3.4%	12,340	2.7%	4.2%
Potrero	**3-6**	**363**			**1,181,258**	**37.1%**	**598,399**	**18.8%**	**891,357**	**28.0%**	**919,958**	**28.9%**	**430,618**	**13.5%**	**25.3%**
note: Potrero 4-6 are gas turbines															
Redondo Beach	5	175	ST	1954	164,530	10.7%	83,476	5.4%	127,576	8.3%	37,455	2.4%	14,631	1.0%	5.6%
Redondo Beach	6	175	ST	1957	383,478	25.0%	47,302	3.1%	30,554	2.0%	24,954	1.6%	17,250	1.1%	6.6%
Redondo Beach	7	480	ST	1967	2,828,873	67.3%	965,701	23.0%	519,163	12.3%	739,056	17.5%	278,134	6.6%	25.3%
Redondo Beach	8	480	ST	1967	2,847,052	67.7%	984,254	23.4%	358,398	8.5%	468,611	11.1%	114,197	2.7%	22.7%
Redondo Beach	**5-8**	**1,310**			**6,223,933**	**54.2%**	**2,080,733**	**18.1%**	**1,035,691**	**9.0%**	**1,270,076**	**11.1%**	**424,212**	**3.7%**	**19.2%**
note: Redondo Beach 1-4 (292 MW total) are retired															
Scattergood	1	179	ST	1958	515,164	32.9%	449,914	28.7%	452,619	28.9%	485,816	31.0%	166,357	10.6%	26.4%
Scattergood	2	179	ST	1959	362,192	23.1%	523,210	33.4%	481,604	30.7%	470,322	30.0%	489,811	31.2%	29.7%
Scattergood	3	445	ST	1974	965,638	24.8%	260,150	6.7%	1,418,880	36.4%	893,637	22.9%	482,824	12.4%	20.6%
Scattergood	**1-3**	**803**			**1,842,994**	**26.2%**	**1,233,274**	**17.5%**	**2,353,103**	**33.5%**	**1,849,775**	**26.3%**	**1,138,992**	**16.2%**	**23.9%**
South Bay	1	147	ST	1960	639,527	49.7%	459,135	35.7%	443,835	34.5%	569,173	44.1%	546,285	42.3%	41.3%
South Bay	2	150	ST	1962	636,790	48.5%	466,098	35.5%	490,090	37.3%	645,722	49.0%	427,043	32.4%	40.6%
South Bay	3	171	ST	1964	603,987	40.3%	319,847	21.4%	442,048	29.5%	600,807	40.0%	434,765	28.9%	32.0%
South Bay	4	222	ST	1971	191,474	9.8%	84,940	4.4%	52,374	2.7%	249,634	12.8%	125,877	6.5%	7.2%
South Bay	**1-4**	**690**			**2,071,778**	**34.3%**	**1,330,020**	**22.0%**	**1,428,346**	**23.6%**	**2,065,336**	**34.2%**	**1,533,970**	**25.4%**	**27.9%**
South Bay	5	13	CT	1966	2,959	2.6%	84	0.1%	1,496	1.3%	1,563	1.4%	692	0.6%	1.2%
note: South Bay 5 is a gas turbine															
South Bay	**1-5**	**703**			**2,074,737**	**33.7%**	**1,330,104**	**21.6%**	**1,429,842**	**23.2%**	**2,066,899**	**33.6%**	**1,534,662**	**24.9%**	**27.4%**

CALIFORNIA ENERGY COMMISSION
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April 12, 2006

Paul D. Thayer, Executive Officer
California State Lands Commission
100 Howe Avenue, Suite 100-South
Sacramento, CA 95825-8202

Dear Mr. Thayer:

Attached to this letter are responses to questions received from you and others regarding the possible effects of the State Lands Commission staff draft resolution pertaining to once-through cooling on the coastal power plant fleet. The questions are organized into three general categories:

- California Energy Commission (Energy Commission) authorities and permitting issues for coastal power plants, and work by the Energy Commission on once-through cooling;
- Current and anticipated operations of the coastal power plants and their contributions to California's electricity supplies; and
- Considerations of the possible effects of the draft once-through cooling resolution on the operation and/or replacement of coastal power plants.

Please call me at 654-4996 if you have any questions or have your staff contact Terry O'Brien at 654-3933 if you require clarification, have questions, or further discussion is necessary.

Sincerely,

B. B. BLEVINS
Executive Director

Enclosure

Question 1 – What is the lead time for issuing permits for new generating capacity?

The Energy Commission has exclusive permitting authority for thermal power plants 50 megawatts (MW) or greater and serves as lead agency under the California Environmental Quality Act (CEQA) for projects within our jurisdiction. The Warren-Alquist Act specifies a mandatory 12-month time period to permit new power plants. Since deregulation of the electricity industry, the Energy Commission has permitted one retooling and three replacement power plant projects on the coast that use once-through cooling (OTC). The time it took the Energy Commission to permit these OTC projects ranged from 3 months for the Huntington Beach retooling project during the energy emergency to 43 months and 46 months for the Morro Bay and El Segundo projects, respectively. The Moss Landing project was permitted in 14 months. The Morro Bay and El Segundo Projects took far longer than the normal permitting time because of disputed issues regarding OTC and the time it took the applicants to supply requested information and address and resolve all the issues raised by the Energy Commission. Permitting time is often proportionate to the difficulty and controversy of the issues that need to be addressed, what issues are in dispute, and the level of community or intervener participation and concern.

In addition to the permit review time, applicants require about 6 to 9 months to prepare an Application for Certification, and 18 to 24 months to construct a project. If an Energy Commission certified project is modified after certification, including modifications to the cooling system, the Energy Commission has jurisdiction over the modification and must approve the modification as an amendment to the decision. Depending on the type of modification, the amendment process normally takes 2 to 6 months to complete.

Question 2 – What is the process for re-permitting the existing plants that would be affected by this resolution?

This question raises several issues about how the coastal power plant owners may choose to respond to a State Lands Commission resolution on once-through cooling over a 14-year time period. The answer to the permit question depends on how each owner chooses to respond. The response options are:

Option 1 – Owners choose to “only retrofit” the cooling system from OTC to cooling towers or dry cooling, but not to modify or replace (i.e., repower) the existing electrical generating system (including the gas and steam turbine generators).

Option 2 – Owners choose to repower the electrical generating system and switch to cooling towers or dry cooling.

Option 3 – Owners choose to replace the electrical generating system with a technology that does not require cooling, such as combustion turbine peaker units.

Under Option 1, if the power plant was not originally certified by the Energy Commission, the installation of cooling towers or a dry cooling system would either require a revision to the original local permit, or for a municipal utility owned project, a municipal utility permit, to ensure conformance with the California Coastal Act, any other affected existing permit conditions, and CEQA. If the power plant was originally certified by the Energy Commission, this option would require an amendment to the Energy Commission's decision and functionally equivalent CEQA documentation would be required and performed by the Energy Commission. While there are environmental benefits derived from avoiding the use of OTC, alternatives that require the use of cooling towers or dry cooling systems are more costly, require more space, and can result in visual and noise impacts. Cooling towers also require a source of reclaimed, ground or potable water. Current Energy Commission policy seeks to encourage the use of reclaimed or recycled water in lieu of fresh water for power plant cooling, but this policy would not apply to projects outside of our jurisdiction.

Under Option 2, an Energy Commission license would be required for facilities not originally permitted by the Energy Commission only if the project modification resulted in a net generating capacity increase of 50 MW or more. If the Energy Commission previously certified the project, a modification of less than 50 MW would require an amendment to the original Energy Commission decision and a functionally equivalent CEQA process. If a local agency or municipal utility previously permitted the project, and the modification was less than 50 MW, the local agency or municipal utility would permit the modification and conduct the appropriate CEQA review. For example, the Los Angeles Department of Water and Power (LADWP) has self-permitted very large power plant replacement projects by keeping the net change below the Energy Commission's jurisdictional threshold.

Under Option 3 where new combustion turbines are installed, the permit requirements would be the same as for Option 2. Because cooling towers or dry cooling would not be needed, these issues would not be evaluated during the CEQA review.

Question 3 – What percentage of the energy actually used by California is generated at OTC coastal power plants? (Not the percentage of capacity). What is the capacity of plants to produce power versus the actual production? What is the relative contribution of the different types of power generators and how might that change over time?

In aggregate, the 21 large coastal power plants using once-through cooling generated 58,345 Gigawatt-hours in 2004, which was 22 percent of total in-state electricity sales. The relative contribution of each technology is shown in the table below.
The capacity factor of a power plant is a measure of the amount of energy it generates in one year. A 100 percent capacity factor means that a facility generates around the

clock each day and hour of the year. The 2004 capacity factors of the coastal power plants with once-through cooling are summarized below.

Technology	Capacity Factor (percent)	Generation as Percent of State Total (2004)
Steam Boilers	19.4	9.0
Combined Cycles	34.9	2.05
Nuclear	79.1	11.08
Combustion Turbine	2.1	0.04

Presently, the older steam boiler power plants operate at relatively low capacity factors on an annual average basis, but provide critical capacity reserves and energy production that are needed to meet peak demand during the summer months. As such, the above table does not adequately reflect the importance of the coastal plants to the state's electricity system, since their generation as a percent of state total is significantly higher during periods of peak demand when system reliability becomes a critical issue. Most of these coastal facilities have been operating at their full capacity during the highest peak demand periods of the summer. Over time, it is anticipated that many of the steam boilers will be replaced with more efficient generating technologies.

Question 4 – Please provide information concerning individual power plants – are any proposed for shutdown by 2020? What about those plants that intend to re-power? Which of these plants seem likely candidates for conversion to non-OTC cooling? Which plants seem obviously not to be a candidate (i.e., location and water limitations)?

As discussed later in the response to Question 9, two plants are no longer operational (Long Beach and Hunters Point), and two more (Humboldt and San Diego South Bay) have announced plans to repower without OTC.

Plants that have recently repowered and the nuclear facilities would encounter difficult financial obstacles if they were to pursue a new cooling technology. Conducting a site-by-site feasibility assessment of cooling technology alternatives is a task that is beyond the scope and time frame of this letter.

Question 5 – What approach has been taken by the Energy Commission and what authority and jurisdiction does the Energy Commission have over OTC power plants?

As discussed in our responses to Questions 1 and 2, the Energy Commission has the legal obligation to thoroughly review potential environmental effects under CEQA for each application on a case-by-case basis and determine whether the impacts are significant and mitigable. The cases involving once-through cooling that have come before the Energy Commission have presented challenging analytic issues for our agency.

The Energy Commission and its staff have created an extensive body of knowledge on OTC issues through its siting, planning and Public Interest Energy Research programs, and through Energy Commission-level policy reports and siting case decisions. In its 2005 Integrated Energy Policy Report, the Energy Commission provided the following policy guidance on once-through cooling:

1. Work collaboratively with agencies on OTC through the Ocean Protection Council.

2. Continue research on impact assessment protocols, impact reduction and alternatives to OTC.

3. Update Memorandums of Agreement with State Water Resources Control Board (SWRCB), Regional Water Quality Control Boards (RWQCB) and Coastal Commission to develop consistent regulatory approaches, including investigating retrofit control technologies (BARCT).

4. Update Data Adequacy Regulations for License Applications and for California Coastal Act consistency.

Question 6 – Are OTC considerations different for the two nuclear power plants?

Yes. California's two nuclear facilities represent billions of dollars in ratepayer investments and operate in a base load mode with very high capacity factors. Recently, the California Public Utilities Commission (CPUC) approved the retrofit of both Diablo Canyon and San Onofre with new steam turbine generators. The large size of these facilities and their impact on the state's generation and transmission systems mean they are critical to the reliable operation of California's existing electricity grid. Potential retrofits would be expensive and present engineering feasibility challenges. Very little information on the potential costs of retrofitting nuclear facilities to use cooling towers is available. In addition, it is unknown whether adequate supplies of reclaimed or fresh water, for example, are available for cooling purposes.

Due to their size and base load operation, the two nuclear facilities also use the largest volumes of sea water. Each plant is permitted to use more than 2,500 million gallons of sea water per day, which is twice as much as the next largest facilities on the coast (Alamitos and Moss Landing). Most of the other coastal facilities are permitted to use less than 1,000 million gallons per day. Due to the low capacity factors at most of the costal plants, actual volumes of sea water used in OTC are lower than their permitted levels.

Question 7 – At the stakeholders meeting, an attorney for Duke's plant at Morro Bay said there were few if any impacts – is this correct and would that be true for the other plants?

In its June 2004 Third Revised Proposed Decision, the Energy Commission found that environmental impacts from OTC to the Morro Bay Estuary from the repowered Morro Bay Power Plant would be less than from the existing plant, and therefore did not constitute a significant environmental impact as defined in CEQA. The Energy Commission Decision also stated that the 16.2 percent proportional mortality entrainment impact from the new facility was an adverse effect and would have to be mitigated in accordance with section 316(b) of the Clean Water Act. The Energy Commission Order directed Duke to pay $12.5 million to the Central Coast Regional Water Quality Control Board for a habitat enhancement program.

The consensus view of federal and state agency scientists that Energy Commission staff have worked with on power plant siting cases is that once-through cooling causes significant, ongoing impacts to marine and estuarine environments in California's coastal waters.

Question 8 – What is being done to insure that new power plants will use alternative cooling systems and not OTC?

There is a substantial amount of work being conducted at the Energy Commission and at other agencies on the environmental impacts of OTC and on the feasibility and development of alternative cooling technologies.

At the Energy Commission, repowering applications that include the continued use of OTC are subject to a thorough regulatory review that includes compliance with Clean Water Act requirements, as implemented by the Regional Water Quality Control Boards, and an examination of feasible cooling alternatives, including the use of recycled water for either cooling towers or once-through cooling. Energy Commission PIER research on alternative cooling technologies is demonstrating that dry and hybrid cooling systems are feasible and economically viable in California.

According to the Energy Commission's *2005 Environmental Performance Report of California's Electrical Generation System*, 22 percent of the new capacity that was brought on-line between 1996 and 2004 used recycled water for cooling, while 52 percent of the capacity under construction or permitting review will use recycled water. Two power plants in California use dry cooling, and a third is under construction.

The Energy Commission staff continues to conduct and sponsor research into the scientific issues associated with better understanding and documenting the environmental effects of OTC.

The recent US Environmental Protection Agency Phase I Rule for section 316(b) of the Clean Water Act effectively bans new power plants, excluding repowers, from using OTC. The Phase II Rule for existing large power plants sets aggressive performance standards for entrainment (60 to 90 percent reduction from baseline) and impingement (80 to 95 percent reduction from baseline). The SWRCB has initiated a proceeding to determine if a more stringent policy to implement the federal rule is appropriate for California. RWQCBs are initiating new reviews of existing National Pollution Discharge Elimination System (NPDES) permits for cooling water intake structures in accordance with the new 316(b) Phase II Rule.

Work at the Ocean Protection Council and State Lands Commission will also result in more attention to and scrutiny and awareness of the impacts of OTC.

Question 9 – What information can the Energy Commission provide on the impact of this Resolution on our State's critical energy needs?

The set of issues raised by this question would depend on how coastal power plant owners choose to respond to the resolution over a 14-year time period. California energy markets and technologies are evolving dynamically and what is true in 2006 may be quite different in 2020. It is helpful to identify some basic facts and assumptions about the coastal fleet and the resolution that can be useful in thinking through a response to this question. In addition to the three response options identified earlier – retrofit the cooling system, repower to combined cycle, repower to combustion turbine – an owner could also choose to retire the plant and use the property for other purposes.

First, it is useful to divide the list of 22 coastal power plants with leases from the State Lands Commission or its grantee agencies into categories. In addition to the conditions of the lease, the type and age of the power plant, along with its location and ownership, will influence how an owner chooses to respond and the number of response options that are available. While the 10 facilities with leases from the State Lands Commission seem to have a legal obligation to comply with the proposed staff resolution, it is not clear what legal authority, if any, exists to compel compliance for the other 12 facilities. In addition, several plants have either shut down or announced that they will repower without once-through cooling systems. Furthermore, two of the plants with leases are small (Gaylord and GWF) and do not meet the 50 million gallon per day threshold for large existing power plants as defined by the US Environmental Protection Agency in its recently revised rule for section 316(b) of the Clean Water Act. The Energy Commission maintains a list of 21 large coastal power plants using once-through cooling that does not include these two small facilities. (The Energy Commission list does includes the Mandalay facility in Ventura County that is not on the State Lands Commission table of leases.)

Accordingly, it may be that just eight plants with leases from the State Lands Commission would be directly affected by the resolution: Antioch, Pittsburg, Ormond, El

Segundo, Huntington Beach and Encina, plus the nuclear facilities of Diablo Canyon and San Onofre.

In terms of technology, the 21 large coastal plants using once-through cooling can be divided into the following categories:

- Nuclear – 2
- Combined Cycle – 4
- Steam Boilers – 15 (plus the old steam units at Moss Landing)

The Diablo Canyon and San Onofre nuclear plants represent billions of dollars in ratepayer investment and provide important levels of base load electricity generation. They are also critical to maintaining system reliability from both a generation and transmission system perspective. Retrofitting these facilities to cooling towers (dry cooling does not appear to be feasible from an engineering perspective) would be an extremely expensive engineering challenge, even if sources of fresh or reclaimed water were available to supplant the use of ocean water for cooling.

Combined cycle technology is the current state of the art for natural gas-fired power plants. Four plants use this technology. Moss Landing and Haynes were recently repowered with continued use of once-through cooling, while the Harbor Units 1a and 2a were built in 1994. Retrofitting to cooling towers or dry cooling would be technically feasible, but would be costly in light of the recent investments to rebuild these generating units.

For the 15 older steam boiler plants, owners could choose from each of the four previously described project options. Retrofitting the cooling systems to cooling towers or dry cooling would probably not make economic sense given the age and lower operating efficiencies of these units. The economic viability and technical feasibility of changing the cooling technology at the time of repowering depends on specific site considerations. The Morro Bay facility still requires and NPDES permit from the Central Regional Water Quality Control Board. Two facilities – Morro Bay and El Segundo – have licenses from the Energy Commission to repower using once-through cooling that have not been exercised. Two plants – Humboldt and San Diego South Bay – have announced that they will repower without OTC. The Hunters Point facility has been granted permission from the California Public Utilities Commission (CPUC) to retire. Finally, the Long Beach plant has ceased generating electricity, but the OTC pumps are still used to control water levels at the plant.

The location of a facility is also a consideration regarding whether to retire, retrofit or repower. Many areas in California are resource-constrained in terms of local generation and transmission. Several coastal power plants in these areas have Reliability Must Run (RMR) contracts from the California Independent System Operator (CA ISO), which obligates the owner to furnish power during periods of critical demand. Nine of the coastal plants have Regulatory Must Run contracts for 2006 for a total of 4,058 MW.

Ownership is another consideration. Merchant generators currently need long-term contracts in order to secure the financing necessary to pay for major facility repowers or retrofits. Publicly-owned utilities, in contrast, have not had difficulty in financing their projects because of their ability to sell bonds. Calpine is in bankruptcy, and Duke is selling its California power plants to LS Power, a privately owned company. Fifteen of the 21 coastal plants are owned by private merchant generators. Passage of the resolution would probably make it more difficult for the merchant owners to secure financing for repowering or upgrading their facilities.

Any generating capacity lost by coastal plant retirements would need to be replaced for electricity supply adequacy purposes and in some cases for transmission stability requirements. If there are transmission-related considerations, the replacement generation might need to be placed in the same general area as the retired coastal plant.

Should the State Lands Commission resolution pass, those existing power plants that would be affected would have two choices, either shut down or modify their facility to eliminate the use of once-through cooling.

For the coastal power plant repowering projects subject to Energy Commission jurisdiction, developers have argued that a requirement to use an alternative cooling technology would render the project uneconomical. While Energy Commission staff has analyzed the costs associated with different cooling technologies and did not accept the assertion of the developers regarding economic feasibility, the question nonetheless remains unanswered regarding economic viability due to a number of factors described above. Consequently, it must be recognized that a State Lands Commission resolution, if passed, could eventually result in the loss of a significant amount of California's generating capacity with adverse impacts to system reliability.

There are two alternatives to OTC. The first would be the continued use of water to cool the power plant, but the source would be fresh or reclaimed water. If the project were under the jurisdiction of the Energy Commission the use of fresh water is unlikely to be permitted, in conformance with a policy adopted by the Commission in its 2003 Integrated Energy Policy Report. The developer would need to use reclaimed water in lieu of fresh water, which is not always available depending on location, or use a dry cooling system. Projects not under Energy Commission jurisdiction would be permitted locally with the lead permitting agency determining what water source could be used for power plant cooling. Currently, it is the policy of the State Water Resources Control Board to discourage the use of fresh water for power plant cooling.

Dry cooling is also an alternative to once-through cooling. This technology is commercially available and has become more common in recent years, particularly in areas where water availability is an issue. However, developers are more comfortable and inclined to use wet cooling technologies because of their greater familiarity with this technology; its lower capital costs; its smaller space requirements; and its greater efficiency, particularly at higher ambient temperatures. The latter issue tends to be more important at inland sites where summer temperatures are normally much hotter than along the coast. If any of the existing coastal power plants have space limitations, dry cooling may not be an option. In addition, since dry cooling systems are noisier and larger than wet cooling systems, there can be environmental issues regarding visual and noise impacts.

In summary, because of the tremendous dynamism of California energy systems, including varied energy technologies and evolving energy markets, energy policies and environmental regulation, it is not possible to state with any certainty how power plant owners would respond to the State Lands Commission resolution over a 14-year phase in period. However, new generation would be needed to replace the loss of existing coastal power plants. New facilities may need to be located at or near some of the existing coastal power plants due to transmission constraints. Coastal generators would face regulatory and financial market uncertainty that could jeopardize the repowering of coastal plants and state goals for meeting resource adequacy in generation / transmission-constrained areas. Such a resolution could mean the early retirement of Diablo Canyon and San Onofre since they might not choose to install the new steam generators recently approved by the CPUC. The loss of such a large amount of generating capacity would have significant consequences for California's electricity grid.

Merchant generator ability to secure financing and long-term contracts for repowering is already uncertain. Incremental cost differences for plants with tower cooling or dry cooling could make coastal plants less competitive than other plants. Loss of nexus to coastal waters could jeapordize the coastal-dependent status for coastal plants subject to Coastal Commission jurisdiction. Finally, regardless of the staff proposed State Lands Commission resolution, the ongoing evolution of technology, market conditions, CPUC procurement and environmental regulatory changes could result in the phase-out and replacement of at least some of the coastal fleet.

Several state and federal policies are currently in place to ensure that system reliability goals are met. Load serving entities (LSEs) such as the private and public utilities have an obligation to serve customers and meet electric load. The CPUC Procurement and Resource Adequacy proceedings are intended to ensure that the LSEs have access to sufficient generating resources to meet reserve margins and resource adequacy goals. The CA ISO RMR program is intended to assure adequate local generation to maintain system operation as well as to guard against the exercise of market power as was done during the Energy Crisis of 2000-2001. The Federal Energy Regulatory Commission Must Offer Tariff requires generators to make their resources available to LSEs. However, should the resolution result in any wholesale retirements of coastal power plants, it is unlikely that these programs would be sufficient to ensure system reliability.

There are other factors to consider when trying to anticipate the effects of the draft resolution on the coastal generators over a 14-year period. The following considerations are drawn from several recent Energy Commission reports.

- Many plants using the older steam boiler technologies are nearing the end of their design life. Their relatively higher heat rates and higher operating costs will continue to render them less competitive over time. More than 3,800 MW of older steam boilers have retired since 2001.

- Current market and system conditions are requiring new capacity to meet peak summer loads, which means that new combustion turbine peaker units may prove to be commercially viable in the near term to serve load centers in coastal areas, rather than base loaded combined cycle facilities. The current coastal plant sites could be appropriate for some of these newer peaker units.
- Notwithstanding current market conditions, new base load generation will be needed to accommodate population growth within the decade, which will create additional demand for base loaded combined cycle units. Such increased demand may incent the owners of coastal plants to repower older facilities, but as previously indicated, decisions will be made on a case-by-case basis.
- The CA ISO RMR program is a temporary solution for ensuring capacity that is intended to be phased out.
- The operations of existing coastal power plants that use once-through cooling will be influenced by the increasing scientific knowledge of once-through cooling effects on marine and estuarine ecosystems, the pending State Water Board policy implementing the United States Environmental Protection Agency 316(b) rule, and concerns over endangered species affected by once-through cooling.