Public Hearing (9/16/09)
Once Through Cooling
Deadline: 9/30/09 by 12 noon

RRI Energy

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SWRCB EXECUTIVE

Jeannine Townsend, Clerk to the Board
State Water Resources Control Board
1001 I Street, 24th Floor
Sacramento, CA 95814

Re: Comment Letter – OTC Policy

Dear Ms. Townsend:

RRI Energy, Inc. (RRI) appreciates the opportunity to submit written comments on the State Water Resources Control Board (SWRCB or Board) Draft Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (Draft Policy) and the associated Draft Substitute Environmental Document (SED). RRI's wholly-owned subsidiaries own and operate two electric generation facilities that will be subject to the regulations under consideration in the Draft Policy.[1]

RRI recognizes that stakeholders have been working for some time towards a policy to implement Section 316(b) of the Clean Water Act (CWA). Unfortunately, we believe that the Draft Policy falls far short of reasonably balancing the complex set of issues involved in adopting a uniform policy on the use of once-through cooling (OTC) in the State of California. The apparent purpose of the Draft Policy is to use the National Pollution Discharge Elimination System (NPDES) process to implement an unapproved energy policy that forces the retirement of over 24% of the state's generating capacity.[2] Not only would this threaten the reliability of the state's electric system (through dependence on a new and untested "advisory" system that has not been officially approved by any agency), but Californians also will be faced with the enormous cost of replacement transmission and generation, at a cost that is wholly disproportionate to any conceivable public or resource benefit. Also, it is incumbent for a new policy to explain why the Draft Policy is better than the current approach used by the Regional Water Quality Control Boards (Regional Water Boards or RWQCBs), but the Draft Policy fails

[1] See the section entitled "RRI Generating Facilities Subject to a Policy on the Use of Once Through Cooling" for a full description of RRI's Mandalay and Ormond Beach Generating Facilities.
[2] Excluding the nuclear and combined cycle units eligible for the wholly disproportionate cost showing, Table 10 of the SED indicates 14,689 MW of OTC capacity, which is 24.5% of the 59,930 MW of Existing Generation identified by the CEC in Table 1 of its Summer 2009 Electricity Supply and Demand Outlook, CEC-200-2009-007, May 2009.

in that respect. As a result of the foregoing, the Draft Policy does not appropriately meet the SWRCB's obligations under Section 316(b) nor its duties under the California Environmental Quality Act (CEQA).

RRI urges the Board to align with more than 30 years of consistent U.S. Environmental Protection Agency (EPA) interpretation and court-approved guidance regarding the Best Technology Available (BTA) standard and the use of a wholly disproportionate demonstration.. The EPA, the U.S. Supreme Court, the U.S. Courts of Appeal, and California Courts have found that in implementing Section 316(b): (1) the use of cost benefit tests is reasonable, (2) industry must be able to reasonably bear the cost of compliance, and (3) it is unreasonable to force individual facilities to bear costs that are wholly disproportionate to the benefit to be gained. Yet the Draft Policy would set BTA, without using cost-benefit tests, at a level that cannot be reasonably borne by the facilities and does not allow forty-five of the fifty-three[3] OTC units the ability to demonstrate that costs are wholly disproportionate to the resulting benefits.

The Draft Policy should be modified to reflect the fact that the law requires minimization of the adverse environmental impacts from the cooling water intakes of these facilities, not the elimination of the facilities themselves; nor mandate changes to generation technologies that have nothing to do with cooling water intake structures. Replacement of an existing generation facility with a new generation facility is not a "technology" to minimize environmental impact, it is an investment decision regarding the future of electric prices.

Without modifications to the Draft Policy, very few of the OTC facilities will be able to comply (since a viable compliance path, such as the proposed provision to allow certain units to demonstrate that costs are wholly disproportionate to benefits, is not available to most of these facilities). Instead, these facilities will face premature shutdown if they cannot economically justify installation of closed cycle cooling towers, putting the SWRCB in the position of determining the reliability and cost of the electric grid. Those decisions lawfully should reside with the State Energy Agencies[4], the Federal Energy Regulatory Commission, and the entities subject to the mandatory and enforceable standards of the National Electric Reliability Corporation. Such authority and responsibility cannot be either informally delegated by those entities to another agency or assumed by an agency having no statutory authority to act in that capacity. Even if the responsibility could be delegated, the staffs of the Energy Agencies do not appear to be in agreement that they serve as only advisors or that cost-benefit tests should not be used to allow facilities to remain operational for grid reliability.[5]

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[3] Only eight units are eligible for a wholly disproportionate showing – two at Diablo Canyon (nuclear), two at San Onofre (nuclear), two at Moss Landing (ccgt) and one each at Harbor and Haynes (ccgts). The other 45 OTC units are not eligible. See SED at pp. 34-35 for a listing of the units.

[4] The term "Energy Agencies" collectively refers to the California Energy Commission (CEC), the California Independent System Operator (CAISO) and the California Public Utility Commission (CPUC).

[5] See July 2009 Draft Joint Agency Staff Paper entitled "Implementation of Once-Through Cooling Mitigation Through Energy Infrastructure Planning and Procurement (Joint Proposal) at pg. 4.

To put this Draft Policy into perspective from the position of RRI, RRI's two plants using OTC cause less than ½ of 1% of the impingement and entrainment impacts (IM/E) at all of the OTC plants[6], and an experienced independent biologist has found that the operation of RRI's two plants does not negatively impact fish or the aquatic environment in the areas they are located. Yet this Draft Policy would force RRI to spend over $200 million to install cooling towers (if the space were even available) at an effective cost of $3,000 per saved fish.[7] Also, a cost-benefit study performed by NERA found that costs to install wet cooling towers at RRI's plants exceeded benefits by a factor of 533 to 1. A policy that would require expenditures of this magnitude, when the benefits are so meager because the existing cooling tower water intake area is healthy and the operation of the plants does not cause significant adverse environmental impacts, is totally unreasonable and must be changed.[8]

RRI's specific concerns with the Draft Policy and the SED are detailed in the attached comments. Additionally, RRI is providing recommended changes to the Draft Policy that are consistent with Section 316(b), as interpreted by the Courts, and which will result in a reasonable OTC policy that will benefit California by minimizing the adverse impact of once through cooling while maintaining the reliability of the electric grid at a reasonable cost.

Sincerey,

Fred McGuire
Vice President
Engineering, Environmental & Safety

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[6] See Tables 2 and 3 of the SED at pp. 31-32

[7] Calculation based on the annual cost of installing and operating closed cycle wet cooling towers at RRI's Mandalay and Ormond plants (if that were even physically possible at Ormond) per the number of adults needed to replace the impinged and entrained species at those facilities taken from Tom McCormick's report contained in Section VII. Using a 20 year amortization period the cost per fish is $2,500, while with a 10 year amortization period the cost is $3,200 per fish. (attached)

[8] NERA Economic Consulting memo to RRI Energy, Inc., "Preliminary Costs and Benefits of Cooling Water Intake Alternatives for Mandalay and Ormond Beach Generating Stations," September 28, 2009, pg. 2, included in Section VII.

Comments of RRI Energy, Inc.

On

The Draft Substitute Environmental Document and the Draft State Wide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling

Submitted to the California State Water Resources Control Board

September 30, 2009

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Executive Summary

The Draft Policy would establish closed cycle wet cooling and a 93% reduction in instantaneous flow rate as the Track 1 Best Technology Available (BTA). The gas-fired steam boilers that comprise the vast majority (forty-five of fifty-three units) of the OTC facilities will likely not find it economically feasible to install such cooling towers. The Draft Policy purports to allow a Track 2 compliance alternative that requires a lesser (83%) reduction for those facilities that can demonstrate that Track 1 is infeasible, but the Policy changes the baseline for Track 2 from an instantaneous flow rate to what is effectively the current actual annual average IM/E impacts. The result is that Track 2 becomes at least as onerous for low capacity factor units (the forty-five gas-fired steam boiler units). Without justification, the Draft Policy would allow the nuclear units and combined cycle units alone the opportunity to demonstrate that compliance costs are wholly disproportionate to benefits, while denying that option to the low capacity factor gas-fired steam boiler units which now have, and will continue to have, a significantly smaller impact on fish and other aquatic life due to significantly fewer operating hours.

RRI believes that the Draft Policy has been created without the requisite analyses and information required by CEQA, fails the test of reasoned decision-making, and goes far beyond the stated objectives of adopting uniform technology-based standards to ease the administrative burden of the Regional Water Boards for implementing Section 316(b) of the Clean Water Act. The Draft Policy creates a BTA standard that ignores the primary purpose of 316(b) to regulate cooling water intake structures, not generation technology, and that ignores more than 30 years of consistent EPA interpretation of this statue by creating a one-size-fits-fits-all Draft Policy that offers alternate compliance pathways that in facr are unavailable to the great majority of the affected plants. Indeed, SWRCB staff has explicitly stated that they do not want the affected facilities to actually install the selected BTA; rather the intent is to force the shutdown of the existing facilities.[1]

The Clean Water Act does not intend for the application of a BTA standard to place "an *impractical and unbearable* economic burden on the operation of any plant."[2] Yet this is exactly what the Draft Policy does. The SED states that the costs of the proposed BTA can be borne by the industry. However, the Tetra Tech Study upon which the SED relies for that statement actually demonstrates that the cost of cooling towers is either infeasible or cannot be reasonably borne by the vast majority of the plants. Thus, the Draft Policy's BTA standard must be replaced in favor of a standard consistent with the purpose of Section 316(b), as interpreted by federal and state courts, which will lead to an economically feasible alternative.

[1] At the September 16 Public Hearing, a senior Water Board staff member at the SWRCB stated "we don't want closed cycle cooling slapped on these old power plants." Rather, these plants should be shut down.
[2] 41 Fed. Reg. at 17388 (EPA's initial 1976 regulations).; Furthermore, the U.S. Supreme Court has found that "'minimize' is a term that admits of degree and is not necessarily used to refer exclusively to the 'greatest possible reduction.'" *Entergy Corp. vs. Riverkeeper, Inc.* 129 S.Ct. 1498, 1506 (2009).

The Draft Policy would clearly require considerable investment in transmission and generation infrastructure, which would inevitably carry significant environmental impacts not even considered in the SED – yet no specific benefits to the improved health of the marine environment are even asserted, let alone demonstrated in the SED. In fact, the scientific evidence in the record indicates that entrainment at OTC plants does not negatively affect coastal populations.[3] For instance, John Steinbeck, the biologist who wrote Appendix E to the SED, which documents the estimates of impingement and entrainment on which the SWRCB staff relied, pointed out during the September 16 Public Hearing, that the SED provided no evidence of the ecological significance of the impingement and entrainment numbers, and nothing about the benefits of the proposed Draft Policy. Mr. Steinbeck went on to explain that benefits from reduced entrainment are limited for species such as gobies, which make up 40% of the entrained larvae, which experience no apparent impact on the spawning population. He further explained that the limiting factor is not the number of larvae but the size of available habitat.[4] Another experienced biologist stated that "it is not clear from the evidence that once through cooling by coastal generating stations creates an Adverse Environmental Impact (AEI) on the biological value of the southern California Bight."[5] Clearly, the SWRCB should understand and provide some evidence of ecological benefits of its proposed Draft Policy before imposing billions of dollars of cost on California and its taxpayers.

The reality is that the Draft Policy is nothing more than an energy policy, with ultimate responsibility for costs and reliability proposed to reside in the hands of the SWRCB.[6] Indeed, the compliance timelines for the Draft Policy are taken from a Energy Agencies' staff paper entitled "Implementation of Once-Through Cooling Mitigation Through Energy Infrastructure Planning and Procurement." In other words, implementation of the Draft Policy should be achieved through the actions of the Energy Agencies, not through installation of BTA by the facility owners.

The Draft Policy seeks to establish an advisory group made up of the Energy Agencies and other governmental entities to advise the SWRCB on compliance dates to cause retirement of existing facilities. This advisory group has no statutory basis, is unfunded and untested, and the SWRCB cannot bind any of these agencies to participate or delegate their statutory responsibilities to the SWRCB. Moreover, the Energy Agencies staffs' stated that (1) more study is needed on retirement dates, (2) their subsequent recommendations must be acted upon by the SWRCB, and (3) cost-effectiveness analyses should be used to justify continued use of a specific unit.[7] Yet the

[3] *See* "Biology of fish species entrained at two Ventura County Generating Stations," Thomas B. McCormick, (September 2009). *See also* testimony at the September 16, 2009 SWRCB Public Hearing by Mr. John Steinbeck of Tenera and Mr. Eric Miller of NBC Environmental Sciences.
[4] See testimony of John Steinbeck at the September 16 Public Hearing.
[5] *See* "Biology of fish species entrained at two Ventura County Generating Stations," Thomas B. McCormick, (September 2009) at 2 (attached).
[6] The arbitrary exclusion of certain ocean intake facilities from the proposed Policy, such as desalination facilities, is evidence that the Policy is directed not at minimizing environmental impacts associated with these facilities, but rather is designed to force retirement of specific energy producing facilities.
[7] *See* Draft Joint Agency Staff Paper on OTC at p. iii, 4.

Draft Policy includes none of these three critical provisions and turns the Energy Agencies into mere advisors. The nature of the electric grid is ever-changing, and electric planning in California has evolved to its current state over many years, but the Draft Policy attempts to codify a new electric reliability and prudence of cost procedure with only a 90-day comment period. RRI suggests that this is not a recipe for ensuring grid reliability and that negative unintended consequences are a foreseeable result.

The Board should reject the Draft Policy and invest the time and resources necessary to restructure the OTC Policy by selecting a lawful BTA supported by reasoned decision-making. RRI believes that a reasonable Policy must include the following:

1) A BTA standard that includes a range of site-specific compliance alternatives to replace Tracks 1 and 2 of the Draft Policy
2) The opportunity for **all** facilities to demonstrate that the cost of compliance is significantly above and/or wholly disproportionate to the benefits of compliance consistent with federal precedent as upheld by the courts
3) No explicit retirement dates in NPDES permits as enforceable conditions[8]
4) Allowing electric reliability and cost decisions to reside with the proper energy agencies

RRI is committed to the California electric market and has no plans to retire Mandalay or Ormond. However, these two facilities, like other OTC facilities, require ongoing capital expenditures to continue to operate, and these investments must be considered in light of the proposed Draft Policy.[9] RRI is environmentally responsible and will make economically rational investments to minimize the impact of OTC at its facilities. For example, RRI is (1) planning to retrofit the Ormond Beach exclusion devices in a manner that would comply with the Draft Policy, (2) evaluating variable speed drives and others measures to reduce the volume of pumping at various operating levels without impacting the ability of the stations to operate when required, and (3) evaluating the seasonal nature of ecological sensitivity to determine whether some change in operations might significantly reduce the small residual impacts of operating these plants.

Under the proposed Draft Policy, however, based on a preliminary cost-benefit assessment of these two facilities, the cost of installing cooling towers would be wholly disproportionate to the benefits of compliance by ***a factor of 533 to 1***, even if significant value beyond the small commercial value of impacted species is assigned to the

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[8] Retirement dates based on Energy Agency planning assumptions should not become legally-binding compliance dates in a facility's NPDES permit. However, a reasonable date by which a facility should be required to implement any technologies or operational changes deemed reasonable and that does not subject a facility to costs "wholly disproportionate to the benefits" and which are necessary to meet the OTC Policy requirements could be made part of the NPDES permit as established by the Regional Water Boards.

[9] For example, RRI faces tens of millions of dollars in essential capital expenditures at Ormond Beach and Mandalay over the next several years.

speculative ecological value of reduced pumping.[10] The Draft Policy would likely force RRI to shut down these facilities since, as proposed, the Draft Policy would not allow RRI to demonstrate that costs are wholly disproportionate to benefits, and subsequently pursue rational and more cost-effective alternatives. RRI believes that the intake flows at both plants can be reduced by nearly 50% from current levels under the current operating regime at a fraction of the cost of installing cooling towers, and that total annual pumping volume can be reduced to a small fraction of design flow at each unit without materially impacting the benefits to the California electric grid currently provided by these stations. If the changes RRI recommends are put into a final policy, then these two facilities are expected be able to make the necessary investments to minimize adverse environmental impacts in compliance with the policy and remain operational.

[10] NERA Economic Consulting memo to RRI Energy, Inc., "Preliminary Costs and Benefits of Cooling Water Intake Alternatives for Mandalay and Ormond Beach Generating Stations," September 28, 2009, pg. 2. (attached)

RRI Generating Facilities Subject to a Policy on the Use of Once Through Cooling

The RRI Energy Mandalay Station (Mandalay) and the RRI Energy Ormond Beach Station (Ormond) are both located in Oxnard, California and are fueled by clean-burning natural gas. The Mandalay Station can contribute up to 560 megawatts of electricity to the grid and was among the first plants in the world to use selective catalytic reduction (SCR) technology to minimize NOx emissions. The Ormond Beach Station can contribute up to 1,516 megawatts of electricity to the grid, and its units are also equipped with SCRs. Both plants economically provide capacity and ancillary services, and are recognized by the CAISO as being necessary for the reliability of the grid.[11]

Mandalay is located at the end of the Edison Canal approximately 2.5 miles from the Channel Islands Harbor, which connects to the Pacific Ocean. Mandalay consists of three generating units, two of which employ once through cooling while the third unit is a combustion turbine that uses no cooling water. The two units that require cooling water have separate, but conjoined, cooling water intake structures. The location of the cooling water intake structure at the end of a long canal isolates it from the natural shoreline habitat of the Pacific Ocean. Elimination of pumping at Mandalay would cause the 2.5 mile canal to become stagnant, imposing potential health impacts on residents, and aesthetic impacts that compromise the value of homes, businesses and public resources located along the canal – none of which have been considered in developing this proposed Draft Policy.

Ormond Beach is located approximately 2.5 miles northwest of the Mugu Lagoon and approximately 2 ½ miles southeast of the entrance to Port Hueneme. It consists of two steam generators that use cooling water withdrawn from a 14-foot diameter pipe that terminates in a vertical intake 1,950 feet offshore, and 32 feet below the surface at low tide. In addition to the offshore intake and a velocity cap, Ormond has a 14" exclusion device at the end of the intake structure.

During the 2000-2001 timeframe, the units were operated as intermediate-peaking units with capacity factors in the 35% - 60% range due to reduced hydroelectric energy output caused by drought. Although both generating facilities have seen reduced operating hours and lower capacity factors over the past ten years, these changes do not imply that the facilities are not needed to reliably operate California's electric grid. As the electrical landscape has changed over the last decade, both facilities have seen their capacity factor fall below 20%, and often below 10%. Changes in the economics of operation have required significant changes in operating practices, requiring that units

[11] "Integration of Renewable Resources: Transmission and operating issues and recommendations for integrating renewable resources on the California ISO-controlled Grid", CAISO, November 2007, page i. "The good news is that this study shows the feasibility of maintaining reliable electric service with the expected level of intermittent renewable resources associated with the current 20 percent RPS, provided that existing generation remains available to provide back-up generation and essential reliability services."

designed to operate as baseload facilities be cycled daily.[12] However, generators such as Ormond Beach and Mandalay, with availability over 90%, are fully committed to provide Resource Adequacy capacity to meet summer peak demands, and are routinely called on by the CAISO for reliability purposes. Also, the units have a much wider range of load following capability.

Both generating stations were designed and originally operated as baseload stations, with high capacity utilization rates. Biological growth in the plants' cooling system at that time was removed by a procedure called "heat treating". This procedure was conducted up to six times a year and was the major factor contributing to facility IM/E losses. RRI's two facilities currently operate as peaking facilities with low capacity utilization rates. As a result, heat treatments have been greatly curtailed and are conducted, at most, once a year. Both facilities minimize the use of circulating water pumps during non-generation periods, further reducing IM/E impacts.

With the State's desire to move towards increasing the amount of renewable generation in the State, these units will continue to have value, since low cost load-following capability and back-up capacity will be necessary to accommodate intermittent resources such as wind generators.[13] Finally, these facilities provide critical local reliability services and are often required to operate when other elements of the Southern California grid are out of service. Mandalay and Ormond also would be essential to serving customers in Ventura and Santa Barbara Counties in the event of any number of significant transmission emergencies, including the loss of the Pardee Substation, for example.[14]

In providing the much-needed reliability service in the Los Angeles area, Mandalay and Ormond contribute less than 0.5% of the SED estimate of all impacts of once through cooling plants.[15] The operation of these facilities has an insignificant impact on their intake source waters and the source waters for both facilities are considered biologically healthy. Furthermore, the use of once through cooling at these facilities does not affect any endangered species.[16]

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[12] To illustrate, in 2008 one of the Mandalay units was committed and ordered to start 239 times, with all 239 being successful starts. This change in operating cycle represents a significant change in the use of this generating technology and has the benefit of reducing operating hours, pumping, and the associated IM/E impacts.

[13] It makes little sense to incur the high capital cost of a new combined cycle facility merely to have that unit serve as back-up to an intermittent renewable generator.

[14] See, for example, SCE Presentation "PUC Workshop – McGrath Peaker Justification", March 2, 2009: "Pardee Substation could be extensively damaged and/or the 230 kV transmission lines that serve Ventura and Santa Barbara Counties could be damaged. . . SCE will have to rely on local generation in the Ventura and Santa Clara systems to serve the load, due to constraints on imports caused by damage to Pardee Substation and transmission lines. . . Local residents, critical load such as military sites, hospitals, police and fire departments, and commercial load could experience extended outages. A reliable local peaker (like McGrath Peaker) is urgently needed to blackstart local generation at RRI Mandalay units. RRI Mandalay can then blackstart RRI Ormond Beach."

[15] SED, Table 2 and Table 3

[16] *See* "Biology of fish species entrained at two Ventura County Generating Stations", Thomas B. McCormick, (September 2009) at p. 4 (attached).

Comments of RRI Energy, Inc. on the Draft Substitute Environmental Document and the Draft State Wide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling

RRI is very concerned that the Draft Policy will result in the shutdown of all but a few of the OTC facilities because its BTA threshold and compliance tracks are virtually impossible to meet. RRI explains in detail below how this Draft Policy (that should be structured to meet the requirements of Section 316(b) of the Clean Water Act) is in effect transformed into an energy policy that threatens the reliability of California's electric grid. RRI will first address the structural defects in the Draft Policy that make it impossible for all but the nuclear plants and combined-cycle units to comply. Next, RRI will explain how the Draft Policy becomes an energy policy conceived and carried out by the SWRCB. RRI will conclude with some specific recommendations that it believes will result in a reasonable OTC Policy that will allow facilities to cost-effectively minimize the adverse impacts of OTC without threatening the reliability of the electric grid.

<u>Section I. Policy Concerns</u>

A. The Draft Policy is infeasible for existing generators and inconsistent with federal guidance

The Draft Policy adopts a "Best Technology Available (BTA)" standard and compliance approach that will be infeasible for virtually all of the OTC plants and goes beyond even that of the EPA Phase I regulations for ***new generating facilities.***[1] The

[1]The EPA Phase I regulations govern the design of intake structures for new facilties, and specify Track 1 and Track 2 requirements that are similar to those in the proposed policy. A notable difference is that under the EPA Phase I regulations, **any** <u>permittee may request less stringent requirements on the basis that costs are wholly out of proportion with costs considered by EPA in establishing the requirement, or that</u>

Section 316(b) rulemaking processes at the EPA has led to separate regulations for new and existing facilities for very simple reasons – it is much more difficult for existing facilities to comply with regulations based on closed-cycle wet cooling, both from a technical and an economic standpoint, than it is for new sources. The Phase I regulations for new facilities contain two compliance tracks, both based on closed cycle wet cooling thresholds, but it allows new facilities to ask for site-specific alternatives based on a cost-benefit determination.[2]

The proposed EPA Phase II regulations did not adopted closed cycle wet cooling as BTA, but rather established compliance at reductions in IM/E of between 60% - 95% of a baseline with a variety of alternative compliance paths based on site-specific conditions. The proposed Phase II regulations did not require low capacity factor units to meet the new compliance requirements and exceptions would also have been available to all affected facilities under a variety of methods, including site-specific methods using a cost-cost test (where a facility could show its costs were significantly above those analyzed by EPA), and a cost-benefit test (where a facility could show that costs were significantly greater than benefits). The cost-cost test was not challenged (and such a test has been previously upheld by the Supreme Court).[3] The site specific cost benefit test was challenged and the Second Circuit court held that the only permissible cost test is whether the compliance cost could be "reasonably borne by industry." The Supreme Court overturned the Second Circuit Court and determined that a test of whether costs significantly exceeded benefits was proper. The SWRCB's own legal memorandum on

significant adverse impacts would result on local air quality, water resources or energy markets. (40CFR 125.84 and 125.85)

[2] 40 CFR 125.85

[3] *Entergy* at 1507, *citing EPA v. National Crushed Stone Ass'n*, 449 U.S. 64, 69-70 (1980).

the Supreme Court's decision in *Entergy* found that the "Supreme Court decision in many ways returns the landscape for Section 316(b) decision-making to the status quo," and that "decisions based on the *more restrictive* "wholly disproportionate" standard are no longer required."[4]

In California, the state court's findings in *Voices of the Wetlands* are consistent with the latest U.S. Supreme Court ruling. The court in *Voices of the Wetlands* found that in determining BTA "an assessment of feasibility properly includes site specific considerations."[5] Also, the court states that "a standard for economic considerations has emerged, commonly referred to as the "wholly disproportionate" test. Under that test, a technology need not be employed if its costs are wholly disproportionate to the environmental benefits to be gained. This standard is reflected in both regulatory and judicial decisions."[6]

For over 30 years, the EPA has held (and both federal and state courts have upheld) that the application of a BTA standard "should not impose an *impractical and unbearable* economic burden" on the operation of any plant subject to Section 316(b).[7]

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[4] Memo from Michael A.M. Lauffer, Chief Counsel, Office of Chief Counsel, State Water Resources Control Board to Dorothy Rice, Executive Director, dated May 6, 2009, re: U.S. Supreme Court's Decision Interpreting Clean Water Act Section 316(b) Requirement for Best Technology Available for Cooling Water Intake Structures (Entergy Corp. v. Riverkeeper, Inc. et al., (2009) 556 US ___ [129 S.Ct. 1498]) (emphasis added).

[5] *Voices of the Wetlands v. Cal. State Water Res. Control Bd.* (2007) 157 Cal.App.4th 1268, 1347 ("voices of the Wetlands"). The case, *Voices of the Wetlands*, was decided in December 2007 and was subsequently appealed to the California Supreme Court. The Court granted review on March 19, 2008 (74 Cal. Rptr. 3d 453) but immediately deferred the case pending the dispositions of the petitions for certiorari in the United States Supreme Court in Entergy Corp. v. EPA. The U.S. Supreme Court issued its Entergy decision on April 1, 2009 (129 S.Ct. 1498) so it is anticipated that the California Supreme Court will again take up the Voices of the Wetlands case very soon.

[6] *Voices of the Wetlands* at 1348.

[7] *Voices of the Wetlands,* 1350 citing 41 Fed. Reg. at 17388. (EPA's initial 1976 regulations) (emphasis added). Furthermore, the Regional Water Board's staff in the Moss Landing case came to a similar conclusion "However, the cost of these alternatives is estimated to be approximately $47 million to $124 million. The estimated value of the entrainment losses is $1.2 to $9.7 million based on staff's habitat equivalency method. Staff's conclusions is that ..the cost of closed cooling systems is wholly disproportionate to their benefit." *Id. at 1328.*

Yet, this is exactly what the Draft Policy does. The Draft Policy ignores this long history, and refuses to establish the BTA standard using a cost-benefit approach. Instead, it relies on the standard created by the Second Circuit of "costs reasonably borne by industry," although the Supreme Court held that the EPA was not limited to considering cost in this manner alone and that the level of benefit achieved was certainly a consideration in determining whether it was reasonable to bear a certain level of costs.[8] Yet, even if one accepts the "reasonably borne by industry" approach, the record demonstrates that the costs of closed cycle wet cooling are not reasonably borne by industry.

The SED's discussion of costs is cursory and based on a metric (cost per kwh) that is inappropriate. Based on the Tetra Tech study, the SED shows the compliance costs as:[9]

Nuclear (4 units)	1.2 c/kWh
Combined cycle (4 units)	0.27 c/kWh
Fossil Steam (45 units)	1.45 c/kWh

The SED compares these costs to a retail rate of almost 13 c/kWh and implies that it is reasonable to increase retail costs by almost 9%.[10] No definition of reasonableness is given. But what really matters is the impact relative to the wholesale price of power, since this determines the competitiveness of an OTC facility subject to the Draft Policy, not the retail price, and is therefore a more the appropriate point of reference for determining whether the cost can be reasonably borne by the industry. Under that metric

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[8] *Entergy* at 1506.
[9] SED at p. 59
[10] SED at p. 110.

compliance cost as a percent of price is almost 24%.[11] But ultimately what really matters for the wholesale industry is not the wholesale price, but revenues after fuel costs. These are the net revenues that are available to cover operations and maintenance expense, capital additions, and a return of and on capital. Using Tetra Tech's own numbers for gross revenues, compliance costs, and fuel prices, and using official fuel burns from EIA, a more relevant picture emerges.

Comparison of Compliance Cost to Net Revenues[12]

Facility	Net Annual Revenue	Annual Cost of Compliance	Cost as % of Net Revenue
Nuclear Plants	$4,303,028,414	$442,700,000	10%
Combined Cycle Plants	$236,414,062	$20,700,000	9%
Fossil Steam Plants	$175,423,833	$146,300,000	83%

Thus, the cost of compliance amounts to 83% of revenues after fuel costs for almost 9 out of 10 OTC units. The 17% net revenue remaining does not leave enough money to cover operations and maintenance expense, much less leave anything available for continued capital expenditures, recovery of depreciation, or return on investment. In short, when 9 out of 10 units cannot cover their operating expense based on the installation cost of a mitigating technology, that technology cannot be considered viable under the CWA.

Not only does the Track 1 BTA in the Draft Policy fail any reasonable economic test, the Track 2 standard is also infeasible. Track 2 is purported to be more lenient, but in fact it is not for the fossil steam units. The Draft Policy establishes flow reductions commensurate with closed cycle wet cooling as the BTA standard for compliance under

[11] Wholesale price in 2006 was 4.7 c/kWh from 2006 Annual Report – Market Issues and Performance at 1. http://www.caiso.com/1bb7/1bb776216f9b0.pdf

[12] See Appendix, Item D.1

Track 1 (e.g. a 93% flow reduction in *instantaneous design intake rate* for each unit) and adopts an equally unreasonable Track 2 standard for low capacity factor plants for whom Track 1 is infeasible – an 83% reduction in actual impingement and entrainment relative to their already low *average* usage. For example, under Track 2, a plant with a 10% capacity factor must reduce its flow by 83%, yielding a 1.7% equivalent capacity factor as the maximum amount it could run. In contrast, a baseload unit that runs 90% of the time needs to reduce flow by 93% under Track 1, giving a flow rate equivalent capacity factor of 6.3%. By changing the baseline measure from an instantaneous input *rate* to the equivalent of actual flow (an average rate) the Draft Policy makes Track 2 infeasible for the low capacity factor OTC units for whom Track 1 is also infeasible. Finally, the Draft Policy denies these very same units the opportunity to make a wholly disproportionate cost showing.

RRI has not identified any practical technology that can be applied that would allow Track 2 compliance (as outlined in the Draft Policy) using 2007-08 circulating water flow estimates as a base.[13] Significant flow reductions, on the order of about 20% to 25% for operational modifications, and up to about 40% to 45% if variable frequency drives are installed on the circulating water pumps, can be achieved without impacting operation at levels similar to what was required to support system reliability requirements in the 2007-08 timeframe. To approach 83% reductions from 2007-08 flow levels would necessitate significant reductions in operating hours/loads from the levels required during

[13] RRI evaluated the following technologies in making that determination in addition to the four options evaluated by NERA: 1)Traveling screen modifications including increased frequency of screen rotation/wash; modified traveling screens with dual flow or Ristroph Screens or fine mesh screens or angled or modular inclined; 3) Fixed screening devices such as wedgewire screens or barrier nets; and 4) fish diversion and avoidance devices such as louvers or bar racks or behavioral barriers including strobe lights, acoustic deterrent or bubble chains.

that base period. Our best estimates are that, even with application of such technologies, reductions in net capacity factor on the order of 70% to 75% would be required to achieve an 83% reduction in circulating water flow from the proposed Track 2 baseline. This would have had the effect of reducing net Capacity Factors on Mandalay Unit 1 from 10.5% to 2.6%, Mandalay Unit 2 from 17.5% to 4.3%, Ormond Beach Unit 1 from 4.9% to 1.2%, and Ormond beach Unit 2 from 8.5% to 2.1%. Restricting the units' operation to this degree will likely render the plants inadequate for meeting the local reliability needs in the Los Angeles region or for justifying the fixed expense and capital additions needed to keep the plants operating.

Since the Draft Policy provides no feasible compliance path, most of the OTC facilities would be forced to retire. In a February 2009 report, the Energy Agency recognized this threat, stating "The SWRCB's proposed policy would require such extensive mitigation that most affected power plants are expected to retire rather than reinvest in control technologies necessary to meet the new requirements."[14] Furthermore, the Tetra Tech work commissioned by the Board shows that it is technically and logistically *infeasible* to install cooling towers at three of the OTC facilities, including Ormond Beach, leaving Track 2 as their only compliance path, as they are also barred from a wholly disproportionate cost determination as discussed in detail in the next section.[15] The SED recognizes that it would be unreasonable to restrict compliance to

[14] "Potential Impacts of the South Coast Air Quality Management District Air Credit Limitations and Once-Through Cooling Mitigation on Southern California's Electricity System," Energy Agencies' Staff Draft Paper (Feb 2009) at p. 15

[15] SED, at p. 58 The Tetra Tech report found that closed-cycle wet cooling is technically and logistically feasible at 12 of the 15 facilities that were part of the study (Alamitos, Contra Costa, Diablo Canyon, Harbor, Haynes, Huntington Beach, Mandalay, Morro Bay, Moss Landing, Pittsburg, SONGS, and Scattergood). Three facilities did not meet the feasibility threshold (Redondo Beach, Ormond Beach, and El Segundo). Retrofitting the State's two nuclear-fueled facilities is problematic, although not infeasible according to the Tetra Tech report criteria.

only Track 1 when alternative methods are available that can be utilized to achieve substantial reductions for low capacity factor steam units. Yet the current Track 2 is infeasible, which is just as unreasonable as having no Track 2 at all. Since both Track 1 and Track 2 are infeasible for most of the facilities, these technologies cannot be considered "available" and therefore do not meet the plain language of Best Technology Available.

An OTC policy that cannot be achieved should not be the objective and cannot meet the legal standard for BTA.[16] In seeking to assure consistency in Regional Board determinations, the Draft Policy makes it impossible for most of the OTC facilities to comply. Only by adopting a logical set of improvements can the Draft Policy achieve the SWRCB's goal of minimizing adverse environmental impacts while allowing consideration of site-specific alternatives that reflect the costs of implementation and retain the reliability of the electric grid.[17]

B. The Draft Policy unreasonably limits the use of a wholly disproportionate determination to just a few facilities

The Draft Policy effectively denies the majority of the OTC facilities a reasonable means of compliance, contrary to federal and state precedent, since it arbitrarily limits the use of a site-specific cost-benefit test to the nuclear facilities and to fossil-fueled generators with heat rates of 8500 BTU/kWh or less. This leaves the fossil steam OTC

[16] *See Voices of the Wetlands* at 1345, *quoting* General Counsel Opinion 41 (EPA, Office of the General Counsel, Opinion 41, June 1, 1976) at p. 3 (" Section 316(b) does not, however, allow for the imposition of closed cycle cooling systems per se.)"

[17] *See Voices of the Wetlands*, at 1347 *quoting Riverkeeper, Inc. v. Natural Resources Defense Council*, 358 F.3d 174, 196 (2nd Cir. 2004) ("Riverkeeper I"), and 1977 EPA Draft Guidance at p. 12 (" "The feasibility of a given technology is a relevant factor in determining BTA. "[EPA was entitled to consider feasibility generally"]. An assessment of feasibility properly includes site-specific considerations. As the 1977 Draft Guidance explains: "The appropriate technology is best determined after a careful evaluation of the specifics at each site."] (internal citations omitted)

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facilities which do not meet these standards with the decision to either comply via Track 1 or Track 2 or shut-down. As discussed above, the BTA standard established in the Draft Policy is not technically or logistically feasible for three of the OTC plants, but more importantly it is not economically feasible for the rest of the fossil steam OTC facilities.

Staff has acknowledged that the cost to comply with the Draft Policy may be prohibitive for almost all of facilities. While the Draft Policy includes a cost-benefit approach for the nuclear units and for the repowered OTC units, the justification for limiting the use of a wholly disproportionate determination has no merit. RRI is not challenging the ability of any nuclear or combined cycle facility to seek alternative compliance options by means of a wholly disproportionate determination, but questions the basis for concluding that these facilities should be the only ones allowed to make such a determination.

With respect to the nuclear units, the SED claims the compliance costs for the nuclear facilities were determined to be "uniformly higher" than that for non-nuclear units, and, because they are deemed "critical" to the state's electric generating system, they were deemed eligible for alternative compliance considerations.[18] This argument fails, because the fossil steam units have higher costs of compliance on both the cited measure (c/kWh) and on the most relevant measure (cost/revenues after fuel costs). Moreover, these fossil steam units are also critical to grid reliability and "must continue

[18] SED at p. 83

to operate."[19] Thus, the main arguments advanced in the SED on why nuclear plants deserve separate treatment do not justify excluding this option for the other facilities.

The repowered OTC plants were deemed eligible for a wholly disproportionate determination because they are able to "generate electricity more efficiently" which "translates to …lower intake water demands when expressed on a per MWh basis."[20] No rationale is given for why a flow per MWh standard is appropriate for providing access to a wholly disproportionate test. Since combined cycle units are slightly more fuel efficient at full load on this standard, SWRCB staff concludes that the environmental harm is less significant as compared to a slightly less efficient steam generator. But harm to the aquatic environment does not occur based on heat rate, it occurs based on actual impingement and entrainment, which the SED assumes elsewhere to be proportional to gallons used. The reality is that the lower heat rate units run more, use more gallons and impinge and entrain vastly more fish and larvae than the fossil steam units with lower capacity factors. For instance, the Moss Landing combined cycle units (Moss Landing 1 and 2) have a rated capacity of 1080 MW compared with Ormond Beach at 1500 MW.[21] Yet Moss Landing 1 and 2 entrains ten times more fish larvae than Ormond Beach (311 million larva vs. 32 million). The numbers for fish impingement are even more pronounced with a hundred-fold difference between the two facilities (57,000 for Moss Landing 1 and 2 compared to 517 for Ormond Beach).[22] Harbor, a much smaller combined cycle unit, also impinges and entrains far more larvae and fish according to the

[19] Draft Joint Agency Staff Paper, "Implementation of Once-Through Cooling Mitigation through Energy Infrastructure Planning and Procurement," (July 2009), at p. 3.
[20] SED at p. 82
[21] The SED, Table 10 shows a capacity rating of 1500 MWs for Ormond Beach; the actual rating is 1516 MWs.
[22] All data from Tables 2 and 3 of the SED.

SED. The Draft Policy allows the lower heat rate plants, even though they entrain and impinge orders of magnitude more larvae and fish, to demonstrate wholly disproportionate costs to benefits, while denying that ability to the plants with the lower impact. This simply makes no sense if the concern is minimizing adverse environmental impact on coastal waters. It only makes sense if the goal is to force retirement of fossil steam boiler generation in California.

Furthermore, the SED's conclusion that heat rate is a good measure is based on the mistaken assumption that the value of electric generation is measured solely by the value of energy produced . If this were true, we would all be sitting in the dark, because it ignores reactive power, capacity, and ancillary services. For instance, capacity (the ability to produce energy) is a critical component on the California electric design, so much so that the CPUC requires utilities to buy what is called a "Resource Adequacy" product. The low capacity factor OTC units have the same capacity value, kW for kW, as base load units under the Resource Adequacy program administered by the CAISO. A more appropriate index for the purpose of determining environmental harm in relation to a unit's value to the electric grid might be the number of operating hours or gallons of seawater pumped per MW of Resource Adequacy capacity. The low capacity factor units would demonstrate lower impacts on marine life by this index. The SED provides no discussion or analysis of this alternative approach to evaluating environmental impact, or any reason why its chosen approach is more reasonable.

Ultimately, from an environmental viewpoint the unreasonableness of the approach to only allow high capacity factor units the ability to demonstrate wholly disproportionate cost is self-evident. The units that run the most and have the most impact on entrainment are allowed the exemptions, while the units that have less flow and less impingement and entrainment impact are deliberately denied the ability to demonstrate wholly disproportionate cost. The SED's next line of reasoning in rejecting the ability of all plants to seek a wholly disproportionate test is that this would "encourage most facilities, if not all, to opt for this compliance strategy."[23] This rationale is arbitrary and an admission both that (1) Tracks 1 and 2 are likely infeasible for most, if not all of the OTC units, and (2) that the costs of requiring BTA as defined in the Draft Policy are wholly disproportionate to the benefits derived for most plants.

The SED then reasons that nuclear units and the repowered units required large investments to build and provide cost-effective energy relative to units with higher heat rates. The relevance of that fact to reducing IM/E is a mystery. In addition, the function of the other OTC units is not to provide cheap MWh, but to provide cost-effective reliability through their ability to provide ancillary services and available installed capacity. No reasonable electric system planner would use a single heat rate standard as the basis for deciding what units to retire, yet that is precisely what staff did. Moreover, Ormond Beach and Mandalay are shown to be essentially as efficient as the combined cycle units in the 1000 gallons/MWh metric created in the SED (the units rank 3rd and 5th on that metric).[24]

On what final basis are these two plants (and all similar fossil steam facilities) denied the wholly disproportionate cost test? The conclusory statement that the "conventional steam units have long since recouped their initial investments" does not

[23] SED at p. 80.
[24] SED, Figure 16, at p. 81

provide a reasoned explanation.[25] RRI Energy has invested millions of dollars in these plants over the last decade, and begs to differ with a statement based solely on the age of the original investment of a prior owner. More importantly, the sunk cost of the original investment is irrelevant to the wholly disproportionate cost test. The test measures whether the incremental cost of minimizing adverse environmental impact is wholly disproportionate to the incremental benefit. Thus, the reasoning supporting the eligibility criteria to make the wholly disproportionate demonstration makes little sense, is arbitrary and should be eliminated.

The United States Supreme Court confirmed that the EPA could rely on a cost-benefit analysis in establishing national performance standards and in providing for cost-benefit variances from those standards.[26] The Court did not overrule the longstanding interpretation of the EPA that while CWA Section 316(b) does not require a cost-benefit analysis, it is unreasonable to interpret Section 316(b) to require technology where its cost is found to be wholly disproportionate to the environmental benefit to be gained.[27] Instead, the Supreme Court confirmed this interpretation while suggesting that EPA's change in its criterion for variances – from a relationship of costs to benefits that is "wholly disproportionate" to one that is "significantly greater" - has ample explanation.[28] The Board's own Chief Legal Counsel has also opined that "decisions based on a more restrictive 'wholly disproportionate' standard are no longer required but may still be used instead of the recently proposed and more lenient *significantly greater* standard.[29] And

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[25] SED at. P. 83
[26] *Entergy* at 1510.
[27] *Entergy* at 1509.
[28] *Entergy* at 1510, fn 8.
[29] Memo from Michael A.M. Lauffer, Chief Counsel, Office of Chief Counsel, State Water Resources Control Board to Dorothy Rice, Executive Director, dated May 6, 2009, re: U.S. Supreme Court's Decision

the Board's Chief Legal Counsel also noted that "[p]rimarily, the *Entergy* decision provides the State Water Board with additional flexibility in construing and implementing section 316(b)."[30] Yet the SWRCB fails to follow both the interpretation of the EPA and its own Chief Legal Counsel in proposing this Draft Policy.

There is no basis for the Draft Policy to allow only a very few OTC facilities to make such a determination. Again, the Draft Policy seems to be targeted at shutting down most of the OTC plants, not in minimizing the adverse impact to the environment, particularly if the significant environmental impacts of replacement transmission and generation infrastructure are considered. The Draft Policy should be revised to allow all facilities to seek alternative means of compliance consistent with federal guidance. The SWRCB should follow the precedence of court rulings regarding Section 316(b) to adopt such a policy and the obligation to adopt state-wide water quality control policies that "attain the highest water quality which is reasonable, considering all demands being made and to be made on those waters and the total values involved, beneficial and detrimental, economic and social, tangible and intangible."[31]

C. The Draft Policy places the SWRCB in the position of establishing energy policy

Since the SWRCB will issue each OTC facility's NPDES permit that will carry with it the obligation to meet the Draft Policy's onerous compliance dates, the SWRCB becomes the final authority on the fate of the OTC plants and thus the reliability of the state's electric grid. Although the staffs of the Energy Agencies made a joint proposal on a process for determining when OTC plants are no longer needed for grid reliability,

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Interpreting Clean Water Act Section 316(b) Requirement for Best Technology Available for Cooling Water Intake Structures (Entergy Corp. v. Riverkeeper, Inc. et al., (2009) 556 US ___ [129 S.Ct. 1498]).
[30] *Id.*
[31] Water Code § 13000.

that process has not been formally adopted by any of the agencies. The timelines in the joint proposal were specifically labeled as "illustrative."[32] And the joint proposal stated that any updates to the schedule "must be used" to change the schedule and that cost-benefit tests should be used to determine whether specific plants should continue to operate, [33] but the Draft Policy does not do either of these things. The Energy Agencies fully realize the implications for electric grid reliability and the cost impact to customers should the OTC plants retire prematurely,[34] yet they are relegated to be advisors to the SWRCB on energy policy.[35] Moreover, the Draft Policy takes the Energy Agencies proposal, which those agencies state "requires substantial further analysis of options" for some regions, and establishes rigid timelines for compliance, even though significant risk and uncertainty surrounds those "illustrative" compliance dates.

An understanding of the role and authority of each Energy Agency in electric system policy, planning, permitting and operations underscores how unreasonable it is for the SWRCB to effectively usurp these roles. The CEC is tasked with licensing and permitting of new generating facilities as well as establishing a state-wide resource plan.

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[32] Draft Joint Agency Staff Paper, "Implementation of Once-Through Cooling Mitigation through Energy Infrastructure Planning and Procurement," (July 2009), at p. 1. "This paper includes in its entirety the proposal made to the SWRCB on May 19 as well as an illustrative schedule for replacing existing OTC facilities. These two items appear as Appendices A and B of this paper. The SWRBC published Appendices A and B of this paper as Appendix C of the Substitute Environmental Document on July 15, 1009.

[33] Draft Joint Agency Staff Paper, "Implementation of Once-Through Cooling Mitigation through Energy Infrastructure Planning and Procurement," (July 2009), at p. 4

[34] At the SWRCB September 16, 2009 public hearing, Dennis Peters of the CAISO said that the Board should give greater deference to the advisory committee, Robert Strauss of the CPUC emphasized the need for flexibility to comply at lowest cost in light of the potential for billions of dollars of cost associated with this proposed policy, and Mike Jaske of the CEC said that power plants should not be repowered if they can operate another 6 or 8 years and act as a bridge to a renewable energy future.

[35] SED at p. C-10

The CEC is now recognizing that, relative to repowering these plants, the existing OTC units can provide a bridge to a future with greater renewable power.[36]

The CAISO, tasked with maintaining the reliability of the electric grid, has recognized the challenges involved with establishing a rigid timeline for compliance and has repeatedly stressed that flexibility in the OTC Policy is essential.[37] The CAISO has stated their preference for replacement generation and transmission to be operational prior to the retirement of the OTC facilities.[38] The CAISO also recognizes that major uncertainties persist related to air quality regulatory issues that prevent generation development in southern California, impediments to transmission siting, the impact of the SWRCB's proposal on nuclear generation, and operational issues associated with integrating intermittent renewable resources.

The CAISO has also emphasized that existing thermal generation is required to integrate renewable resources. In its 2007 report on integrating 20% renewable generation into the electric system, the CAISO stated that "the good news is that this study shows the feasibility of maintaining reliable electric service with the expected level of intermittent renewable resources associated with the current 20 percent Renewable Portfolio Standard (RPS), provided that existing generation remains available to provide

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[36] At the September 16 Hearing, Dr. Mike Jaske of the CEC stated that the CEC did not want to repower projects now "if we can wait 6 or 8 years to replace with renewables" and further that some continued operation of these plants can serve as a bridge

[37] Draft Joint Agency Staff Paper, "Implementation of Once-Through Cooling Mitigation through Energy Infrastructure Planning and Procurement," (July 2009), at p. 2. The paper indicates conditional agreement with establishing a fixed-year outer bound for OTC compliance requiring the following conditions be met, "provided it allows for the orderly development of necessary replacement infrastructure and can be amended if conditions, such as permitting and construction delays, indicate that amendment is needed to ensure reliability."

[38] Draft Joint Agency Staff Paper, "Implementation of Once-Through Cooling Mitigation through Energy Infrastructure Planning and Procurement," (July 2009), at p. 2

back-up generation and essential reliability services."[39] The importance of existing low capacity factor generation needed for management of system reliability may become more important with a recent gubernatorial directive to increase California's RPS to 33% by 2020. [40] At the very least, the ramifications of such an increase in renewable capacity on electrical system needs should be evaluated prior to establishing hard compliance dates based solely on a Draft Policy designed to promote retirement of 24% of the State's generating capacity.

The CPUC is tasked with oversight of the IOUs long-term procurement, contracting, infrastructure investment and electric rates. The CPUC has clearly indicated a concern with cost.[41] It also has formally adopted a policy for utility procurement of preferred resources pursuant to California's Energy Action Plan (EAP).[42] The CPUC recognizes the value the fossil-fueled OTC units have for reliability purposes and they have instructed the IOUs to "to procure dispatchable ramping resources that can be used to adjust for the morning and evening ramps created by the intermittent types of renewable resources." Under this procurement policy, preference is to be given to procurement that will encourage the retirement of aging plants, particularly inefficient facilities with once-through cooling, by providing, at a minimum, qualitative preference to bids involving repowering of these units or bids for new facilities at locations in or near the load pockets in which these units are located." [43] Note that "encouragement"

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[39] "Integration of Renewable Resources: Transmission and operating issues and recommendations for integrating renewable resources on the California ISO-controlled Grid", CAISO, November 2007, page i.
[40] Executive Order S-21-09 signed by Governor Arnold Schwarzenegger on September 15, 2009.
[41] At the September 16 public hearing, the CPUC representative (Robert Strauss) recommended that the SWRCB consider the cost impact of the Draft Policy, noting that replacing cooling systems will be "very expensive" and that the cost and environmental impacts of alternative power supplies may be high – meaning that the Draft Policy may impose billions of dollars of costs on customers.
[42] CPUC Decision, D.07-12-052, issued in December 2007
[43] CPUC Decision, D.07-12-052, issued in December 2007, pp. 106, 112, 115

and "qualitative preference" are a far cry from establishing a policy to require the OTC units to retire.

The joint proposal from these three agencies does not envision them in an advisory role. Moreover, the first of the three policy objectives they note is to, while assuring reliable operation of the system, "retire and/or repowering all aging power plants unless cost effectiveness analysis justifies continued operation…[of those plants]" [44] Yet the Draft Policy ignores the first of the Energy Agencies objectives and does not allow cost effectiveness tests for continued operation of specific units.

The Energy Agencies statutory authority cannot be effectively transferred to the SWRCB through the Draft Policy. The Draft Policy should be revised so that the Energy Agencies are not simply "advisors" to SWRCB on the retirement of the OTC plants. Rather the Energy Agencies must retain the necessary authority for electric reliability and cost oversight.

The Energy Agencies illustrative timeline to implement the OTC Policy through energy infrastructure planning and procurement changes is included in the SED as Appendix C and was discussed fully discussed in a Staff Paper.[45] Careful examination of these documents shows that the Draft Policy has deviated from key policy preferences by relying on "draft" or "preliminary" determinations to establish rigid compliance dates based on Energy Agency planning dates that will be legally-binding on the OTC owners. The Energy Agencies indicate a preference for replacement facilities to be operational

[44] Draft Joint Agency Staff Paper, "Implementation of Once-Through Cooling Mitigation through Energy Infrastructure Planning and Procurement," (July 2009), at p. 4
[45] Draft Joint Agency Staff Paper, "Implementation of Once-Through Cooling Mitigation through Energy Infrastructure Planning and Procurement," (July 2009), at p. 1

prior to retirement of the OTC facilities and that flexibility in the Policy is needed.[46,47] Yet, the Draft Policy includes rigid compliance dates, while the Energy Agencies' staff proposal contained in Appendix C of the SED indicates that the operational dates for the replacement infrastructure is known for only six of the OTC plants.[48]

Even more troubling is that the Draft Policy makes the compliance requirements considerably more restrictive than the Energy Agencies envisioned. These "draft" compliance dates become legally-binding as they are included in each facilities' NPDES permit and the addition of an "as soon as possible" mandate adds unnecessary ambiguity. Some might later argue that, since the Energy Agencies are only advisors, "as soon as possible" means that all OTC facilities would either have to immediately comply with Track 1 or Track 2 of the Draft Policy, or shut down.

The CAISO argued against an OTC policy that would have caused the shutdown of all low-capacity factor OTC plants by 2015 when the Board's March 2008 Scoping Document was under review and comment. Based on studies conducted at that time the CAISO found that the units could not all retire by 2015 without some repowering or replacement of generation in the same local area.[49] The ambiguity and potential for future adverse ruling could cause the unintended consequence that the OTC operators will lower investment in the plants, which could result in lower reliability. For that reason, it is strongly recommended that the "as soon as possible" language be deleted.

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[46] Draft Joint Agency Staff Paper, "Implementation of Once-Through Cooling Mitigation through Energy Infrastructure Planning and Procurement," (July 2009), at p. 2 and 3

[47] Potential Impacts of the South Coast Air Quality Management District Air Credit Limitations and Once-Through Cooling Mitigation on Southern California's Electricity System"; Energy Agencies' Staff Draft Paper, (February 2009)

[48] SED, Appendix C, p. C-9

[49] CAISO comment letter, dated May 20, 2008
http://www.swrcb.ca.gov/water_issues/programs/npdes/docs/cwa316_may08/comments/jim_detmers.pdf

The Draft Policy attempts to deal with the Energy Agency's desire for flexibility and need for replacement facilities to be operational by establishing a newly developed and untested multi-agency process for revising the compliance dates. However, the process is only done on a bi-annual basis and the first opportunity to revise the compliance schedule will come after the SACCWIS submits its report to the State SWRCB on 3/31/2011.[50] Prior to that time the OTC owners must make business decisions relative to the rigid compliance dates and their ability to comply with the BTA standards in the Draft Policy. Lower investment, now driven by an energy policy driven retirement date, is a foreseeable consequence of the current compliance schedule construct, and the reliability implications of this unintended consequence needs to be evaluated before the Draft Policy is adopted.

D. The Draft Policy appears to be aimed at the Energy Agencies, not the owners of the facilities

An irony of the Draft Policy is that its operative parts are meant to force the Energy Agencies to act, not the owners of the facilities, despite the SED's statement that the SWRCB must act urgently to address the "critical state of California's coastal ecosystems."[51] Yet SWRCB staff stated they do not actually want owners to install BTA at the existing facilities. Indeed, the result of the Draft Policy would be that 9 out of 10 plants will not be able to comply. Instead, staff wants those facilities retired in favor of new generating units or new transmission. The only way that new transmission and new generation can be built is by requiring the Energy Agencies to act, because transmission must be built by utilities and no competitive market currently exists that would allow new

[50] Appendix A of the SED at p. A-6
[51] An unsupported assertion in the SED at p. 44

generation to be built without a contract from a utility, which again requires Energy Agency action. If such alternatives to the fossil steam OTC facilities were constructed, these OTC facilities would shut down on their own, as they would no longer be economic to operate.[52] The owner would do so without the need for an NPDES permit "end date" to determine the business future of the OTC generating assets. .

Of course, the Energy Agencies could pursue such action on their own, but they would have to follow their own rules and procedures to do so, including allowing affected parties the right to be heard, and providing an adjudicatory forum to litigate issues of cost and benefit. To be sure, if the goal is to shut down fossil steam OTC plants, it might appear to be far easier to do through the back door of a water policy, than through the Energy Agency processes. The fixed compliance dates and the advisory nature of the Energy Agencies under the Draft Policy will force the Energy Agencies to act to avert a reliability catastrophe and attempt to override the due process requirements of the statutes governing electricity policy.

RRI suggests that the Clean Water Act was not meant to be a vehicle for energy policy.

E. The Draft Policy has been developed without comprehensive consideration of all relevant issues

RRI appreciates that the Board has been in the process of developing an OTC Policy for a number of years and has solicited input from multiple state agencies, including the Energy Agencies. Nevertheless, RRI believes that the Draft Policy has not

[52] For instance, see Mirant's September 3 announcement of the shutdown of Contra Costa 6 and 7 along with a 10 year contract with PG&E for the output from new gas turbine peakers. Press release available at: http://investors.mirant.com/releasedetail.cfm?ReleaseID=407092

been developed through comprehensive consideration of all the relevant issues.[53] The Draft Policy relies much too heavily on highly speculative compliance dates based upon a limited number of preliminary electric reliability evaluations and leaves unresolved too many issues related to the possibility of the premature retirement of over 24% of the state's generation capacity. Furthermore, the economic implications of this Draft Policy are tremendous, yet the cost assessments that have been made to date are woefully lacking.

RRI has compiled a representative, but not comprehensive, list of items identified either by the Energy Agencies or Staff in the SED as unresolved, analytically incomplete, or not addressed in the development of the Draft Policy.[54]

1. Issues identified by the Energy Agencies as being unresolved

a) Air pollution credits in the South Coast Air Quality Management District (SCAQMD) for new power plants displacing OTC power plants, or repowers of existing OTC plants/units to eliminate OTC cooling technologies;

b) Sequencing of bidding into utility RFOs versus permitting a facility;

c) Reliance upon conventional generating facilities or preferred technologies

d) Analysis of the nuclear generating units at San Onofre and Diablo Canyon; and

e) Development of a comprehensive plan and preferential treatment of elements of the Plan in licensing proceedings compared to proposed facilities not included within the Plan.[55]

2. Items Staff identified as needing further review in the SED

a) The importance of the nuclear plants to the electric system and the secondary-impacts of nuclear facilities on greenhouse gases[56]

[53] The following agencies were included: The California Energy Commission, the California Public Utilities Commission, the California Coastal Commission, the California State Lands Commission, the California Air Resources Board, and the California Independent System Operator. http://www.swrcb.ca.gov/water_issues/programs/npdes/cwa316.shtml
[54] See Section VI for RRI's detailed discussion of the SED.
[55] SED, Appendix C at p. C-6

b) Cost-based feasibility study of the installation of cooling towers at the OTC facilities[57]

c) Entrainment or impingement proportionality to the volume of water withdrawn from a cooling water intake structure[58]

d) Cumulative environmental impact studies[59]

3. Items not considered or given only a cursory review by Staff

a) No evidence provided to support Staff's claim that low-capacity factor units can cause greater harm to the environment than baseload units. (In fact, this claim is an impossibility.) The SED itself provides a contradiction to this assumption in its discussion of the two nuclear facilities:

"Diablo Canyon and SONGS can impinge and entrain substantial numbers of aquatic organisms just by virtue of the sheer volume of cooling water required each day—4.8 billion gallons of cooling water per day based on their design capacities (see Section 2 of this staff report). Because of their status as base-load facilities and corresponding high capacity utilization rates, both Diablo Canyon and SONGS typically withdraw close to their maximum capacity on an annual basis, which accounts for approximately one third of all cooling water withdrawn by the State's coastal OTC facilities. By comparison, the 2005 annual average intake for the 17 fossil-fueled coastal OTC facilities was 9.4 billion gallons per day."[60]

b) No studies performed to support the staff's conclusion that there will be little to no cumulative or long-term impacts of the policy. No regional environmental or electric grid studies have been performed to consider the effects of multiple plant closures even though the SED notes that it will be difficult to close all of the OTC facilities located in the Los Angeles region.

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[56] "Furthermore, the outsized importance of Diablo Canyon and SONGS to the State's electric system warrants closer consideration of secondary impacts (e.g. , greenhouse gas emissions" that could be significant due to their size. To this end, the proposed Policy includes requirements for nuclear-fueled facilities to fund third party feasibility studies that will evaluate alternative requirements in greater detail." SED at p. 48.

[57] "Tetra Tech also prepared a 20-year cost estimate based on the conceptual design but *did not evaluate feasibility based on cost.*" SED at p. 7

[58] "The State Water Board concedes the possibility that entrainment reductions might vary slightly from the flow-based estimate but considers them insignificant and acceptable compared to the reduced burden this alternative would place upon both the facility and Regional Water Board." SEDat 62

[59] SED at p. 33

[60] SED at p. 47

c) The SED also concludes that some actual net increase in greenhouse gas emissions will occur, and without any objective analysis concluded that such impact will have a "less than significant" impact to the environment.[61]

4. CAISO studies that need to be completed

a) CAISO Local Capacity Requirement (LCR) studies to assess resource adequacy requirements and the minimum amount of local capacity necessary to meet applicable reliability criteria, particularly in the Los Angeles basin and adjacent areas; and

b) CAISO long-range transmission planning studies that account for increasing renewable energy targets of up to 33%.[62]

5. Combined Energy Agency Study that needs to be completed

The only study of electric system impacts relied upon in the SED was performed in April of 2008[63] and has not been updated even though its findings and conclusions were challenged by the CAISO.[64] Therefore, a comprehensive state-wide transmission analysis and cost-impact study and environmental review should be conducted and should include the following:

a) The cost of OTC mitigating technologies including installation of cooling towers and intermediate measures including habitat restoration,

b) State-wide transmission cost (Estimates range from $4.5 billion for the LA Region to $11 billion statewide)[65]

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[61] SED at p.101

[62] On September 15, 2009, the CAISO has published its "2020 Renewable Transmission Conceptual Plan Based on Inputs from the RETI Process – Study Results" that is available at http://www.caiso.com/242a/242ae729af70.pdf

As noted in the CAISO's document at p.e 5: "(T)he scope of this report does not include consideration of operational requirements (such as ramping, regulating capacity and operating reserves) for integrating renewable generating capacity sufficient to meet the state's 33% RPS goal. The ISO is developing a separate report that will address operational requirements at the 33% RPS level by the end of the year."

[63] Study commissioned by the California Ocean Protection Council and State Water Resources Control Board, "Electric Grid Reliability Impacts from Regulation of Once-Through Cooling in California," ICF Jones & Stokes, April 2008

[64] At the Water Board's May 2008 Hearing , the CAISO stated that the Report was too optimistic in two respects: that the OTC resources have local and zonal reliability benefits that transmission solutions alone can not provide and even if that were the case, that the transmission upgrades could be done in a 1-3 year time period for the cost stated in the report. Comments of Jim Detmers, May 20, 2008.

[65] "Impacts on Electric System Reliability from Restrictions on Once-Through Cooling in California", Preliminary CAISO ISO Scenario Analysis, November 25, 2008, Slide 21 and Jones & Stokes Report (Footnote 16), p. 5

c) Replacement generation cost

d) Impacts on the transmission import limits, and the availability of incremental out-of-state supply

This list alone should indicate to the SWRCB that much work remains to be done before a final OTC policy is adopted. While it is important to have a full understanding and management plan for dealing with each of the issues note above, it is imperative that the CAISO complete the regional reliability assessments and that work is just now beginning.[66]

As an additional example, the Los Angeles region has been identified as being the "most problematic" reliability area due to the current unavailability of sufficient air emission credits needed for new generation development,[67] and difficulties in completing transmission solutions due to greater potential for significant local opposition.[68] While the Draft Policy provides five additional years for compliance in that geographical area, the SED provides no evidence demonstrating that the necessary replacement transmission or generation infrastructure will be in place by 2015, 2020 or even 2025.

An added complexity in this geographic region is that three of the of the OTC facilities are operated by the Los Angeles Department of Water and Power (LADWP), an entity which does not fall under CAISO balancing authority or CPUC jurisdiction.[69] A note in the SED states that the "Energy Commission hopes to facilitate LADWP's cooperation in the Plan; however, absent such cooperation the Energy Agencies will proceed to develop the plan as it pertains to OTC power plants within the ISO's

[66] Appendix C of the SED indicates that the CAISO will begin the first of the Enhanced Local Capacity Requirements assessments in the 4th quarter 2009, p C-9.
[67] "Implementation of Once-Through Cooling Mitigation Through Energy Infrastructure Planning and Procurement", Draft Joint Agency Staff Paper, July 2009, p8
[68] SEDat p. A-3
[69] SEDat p. C-9

balancing authority area."[70] Since any generation facilities needed to replace LADWP's OTC facilities will be competing for the same air permits with CAISO area generation, it seems that reliability study coordination with LADWP would be paramount, yet the Draft Policy indicates that it will proceed without LADWP's cooperation if necessary. The only recommended solution is for the Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS) to "assist" the SWRCB in evaluating compliance for the LADWP facilities.[71] Eight of the OTC facilities are located in the L.A. region and have firm compliance dates even though reliability work for that region is not complete. An EA Staff report from July 2009 indicates that the analytic work necessary to evaluate the regional impacts of the OTC Policy will continue through 2010 with the results of the various regions released as completed.[72] To further compound the problem, a presentation given by the CAISO in November of 2008, indicates that WECC entities and neighboring state regulatory agencies may prove to be significant barriers to transmission siting, yet no timeline or plan for resolving the transmission siting issues has been formulated to RRI's knowledge. Clearly, further analysis and planning by the Energy Agencies, and numerous other agencies is required before the SED and OTC policy can be finalized.

Section II. Recommended Changes to the Policy

In the sections below, RRI will discuss its recommended changes to the policy in detail. RRI is also providing a mark-up of the Draft Policy (provided in Section IX) consistent with the recommendations shown below.

[70] SEDat p. C-3
[71] SEDat p. A-3
[72] "Implementation of Once-Through Cooling Mitigation through Energy Infrastructure Planning and Procurement" Draft Joint Agency Staff Report at p.8

<u>RRI Recommendation #1</u>: ***Establish a reasonable BTA for all facilities or provide a specific exclusion for low-capacity factor units.***

The Draft Policy's infeasible BTA standard combined with an inability to seek compliance alternatives through a wholly disproportionate cost determination leaves the vast majority of the OTC plants unable to comply. Therefore, RRI recommends a change to the Draft Policy's BTA standard. Track 1 and Track 2 of the Draft Policy should be replaced with a single standard that defines the BTA to be any technology, or combination of technologies and operating conditions, that allows a facility to achieve an 80% reduction from a facility's annual intake design flow (provided that any facility could demonstrate an alternate BTA for site-specific reasons). Adopting this BTA standard recommended by RRI will give credit for technological and operational conditions that already exist at an individual facility, such as operating at low-capacity factors for the steam units. More importantly, it would allow the facilities to install equipment other than cooling towers, such as variable speed pumps, to achieve the 80% reduction. Establishing this reasonable BTA standard would achieve the goal of minimizing the adverse impacts and mitigating the damage to California's coastal waters from the use of once through cooling without threatening the reliability of the electric grid. Adopting this threshold would also avoid imposing billions of dollars in unnecessary costs on the citizens of California.

To summarize, RRI recommends the following BTA standard:

1. A BTA standard that requires an 80% reduction in the facility's annual design intake flow;[73]

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[73] The EPA's Phase I regulations for new facilities has two compliance tracks. Track I requires a facility's intake flow to be reduced to a level commensurate to that achieved with a closed-cycle wet cooling system; Track II facilities must reduce intake structure impacts to a level *comparable* to that achieved by closed-cycle wet cooling. To meet the "comparable level" a facility must demonstrate that both impingement mortality and entrainment of all life stages is reduced by 90% or greater than that which could be achieved

2. Existing technologies installed at the plant and operating conditions (such as low utilization rates) will be credited towards the 80% reduction

3. Additional site specific technologies or operational changes (such as using only one cooling water pump during low-load operations, or agreeing to a time-based cap on operations) may be utilized to meet the BTA standard

4. Any facility may demonstrate that site-specific issues can justify a different BTA.

Should the SWRCB decline to adopt this standard, RRI believes it is necessary to give low-capacity factor units an explicit compliance alternative to the Track 1 or Track 2 threshold in the Draft Policy.

<u>RRI Recommendation #2:</u> ***A final Policy should allow all OTC facilities to make a wholly disproportionate demonstration consistent with federal and state guidance.***

As explained earlier in RRI's comments, there is no basis for the Draft Policy's restriction on the use of a wholly disproportionate demonstration to the nuclear plants and combined-cycle facilities. The rationale provided by staff is that these units full load service operating efficiency justifies this restriction. However, if the objective of the Policy is to mitigate the impact of once-through cooling on California's coastal waters, this restriction makes no sense as these facilities actually cause the most impact since they run at considerably higher capacity factors throughout the year. On the other hand, if steam units are not running, they are not impinging and entraining fish, eggs and larvae. As explained earlier, RRI is not questioning the ability of the nuclear and combined cycle plants to make a wholly disproportionate cost demonstration, because the cost of compliance at these facilities may well be above the benefits derived and they

by a flow commensurate with closed-cycle cooling and an intake velocity of 0.5 ft/s. See § 125.86(c)(1) More importantly, EPA's Phase I regulations allow facilities to seek compliance alternatives through a site-specific cost test.

should be allowed to make such a demonstration, but so should all of the other OTC facilities. The fact is that the Supreme Court in *Entergy* established cost-benefit tests as a valid reason for seeking alternatives to BTA and made no restrictions on any facility's ability to seek site-specific alternatives based on cost. Finally, any plant should have the ability to demonstrate that its operation is not having an adverse environmental impact on the state's coastal waters. RRI has included a recently completed report from an independent biologist on its plants. The report concludes that RRI's plants do not have a negative impact on their intake source waters. It makes no sense to require the expenditure of hundreds of millions of dollars if a plant is not adversely affecting water quality.

RRI Recommendation #3: ***The cost amortization period utilized in making a wholly disproportionate demonstration should be changed from 20 years to no more than 10 years and costs and benefits should be measured in net present value, not $/MWh***

The Draft Policy provides instructions for making a wholly disproportionate determination that includes expressing a facility's cost of compliance in terms of $/MWh produced over an amortization period of 20 years. This period is not reasonable. For example, the plants that have an early compliance date, such as 2015, are presumably no longer needed for reliability purposes after that date. With the potential for only five more years of operation, it makes no sense to assume that the investments made to comply with the OTC policy could be recovered over a 20 year period! For other facilities, such as RRI's Mandalay and Ormond units, the compliance dates are set ten or more years down the road. A realistic amortization period of 20 years means that any investments made by RRI to comply would need to be recovered until 2040, over thirty years from now. There is a disconnect between the expectations Staff has about the longevity and efficiency of these units and the period of time over which the owner could reasonably be expected to recover costs. The amortization period should be no more than 10 years.

Additionally, it makes no sense to have a wholly disproportionate test with costs based on dollars per MWh and benefits based on an indeterminate measure. How can one determine whether costs are wholly disproportionate to benefits if the bases are not comparable? Are the Regional Boards supposed to calculate habitat production foregone per MWh? As the NERA report shows, the widely accepted way to compare cost and benefits is to use net present value, and that should be adopted here.[74]

<u>RRI Recommendation #4:</u> *Remove hard "retirement" dates and "as soon as possible" language from the Policy.*

If the SWRCB adopts RRI's earlier recommendations, compliance dates are not an issue because compliance could be achieved by most units. But if the SWRCB does not change Tracks 1 or 2, then a hard compliance date will create a problem. The compliance dates listed in the Draft Policy are presumably dates which represent the time that the Board believes the units could be retired without compromising the reliability of the electric grid. With the convening of an "advisory board" on a biannual basis, the Draft Policy presumes the compliance dates that are based on Energy Agency planning dates might be "adjusted" by means of a policy change. A policy should be revised infrequently. The incorporation of these dates into each facility's NPDES permit makes them legally-binding. Thus, in order to have any planning flexibility on the part of the plant owners and the Energy Agencies, the Policy would need to be revised frequently.

[74] NERA Economic Consulting memo to RRI Energy, Inc., "Preliminary Costs and Benefits of Cooling Water Intake Alternatives for Mandalay and Ormond Beach Generating Stations," September 28, 2009, pg. 3, included in Section VIII.

This would be a significant administrative burden on the Board and Staff, as well as the Regional Boards and defeats the goal of reducing workload.

Moreover, the owners of the facilities are faced with a mandate to install closed cycle wet cooling "as soon as possible, but no later than" edict which places them in a position of having to make a business decision in the face of the ambiguity of the phrase. It will be difficult to justify ongoing investment with the threat of forced retirement from an interpretation of "as soon as possible" as discussed earlier. Further compounding this problem is that the Draft Policy provides no realistic, cost-effective opportunity for most of the facilities to comply. The Draft Policy should not contain such dates or make them permit conditions based on suppositions, but instead should rely on the current processes of the appropriate energy planning agencies. The compliance dates should not be included in the Draft Policy and the "as soon as possible" language should be removed from the Draft Policy.

RRI Recommendation #5: ***The advisory SACCWIS should not be part of the Policy***

The inclusion of rigid compliance dates along with the "as soon as possible" language in the Draft Policy puts electric reliability decisions into the SWRCB's hands as RRI has explained above. So long as the SWRCB is not placed in the position of establishing energy policy, aformal advisory board is not needed, as there is nothing that prohibits the SWRCB from conferring with another agency at any time. A reasonable way to assist the Regional Water Boards in evaluating BTA for a facility and a facility's request for alternative compliance options through the wholly disproportionate cost test, is to direct the Regional Water Boards to consult with the CAISO on an as-needed basis on the need for a facility for electric reliability purposes, and to factor that need into the cost-benefit test..

Section III. The SED fails to meet CEQA requirements

The California Environmental Quality Act (CEQA) requires state and local agencies to identify the significant environmental impacts of their actions and to avoid or mitigate those impacts, if feasible.[75] The purpose of environment review pursuant to CEQA is to provide information necessary for informed decision-making and informed public participation. RRI believes that the Draft Substitute Environmental Document (SED) fails to meet CEQA requirements in several respects. Specifically, the SED fails to analyze an appropriate range of alternatives to the proposed Draft Policy, fails to provide a reasoned explanation for why certain alternatives were rejected, and fails to adequately analyze the reasonably foreseeable environmental impacts of the proposed Draft Policy. The SED omits material that the SWRCB needs to make intelligent decisions and that the public needs to effectively participate in this process. The specific failures identified are discussed in more detail below and in Section VI.

A. Reasonably Foreseeable Environmental Impacts

When adopting a rule or regulations requiring the installation of pollution control equipment or a performance standard, an agency is required to prepare an environmental analysis of the reasonably foreseeable methods of compliance, including their reasonably foreseeable environmental impacts.[76] In this case, the SED identified several "alternative technologies" and operational controls, but failed to identify or analyze any of the

[75] http://ceres.ca.gov/ceqa/more/faq.html

[76] Pub. Res. Code § 21159(a).

reasonably foreseeable environmental impacts associated with those technologies and controls.[77] The construction of these pollution controls would have at least some environmental impacts that are reasonably foreseeable, just by virtue of the fact that they require installation.

The SED also failed to identify any cumulative impacts, or explain whether any impacts were considered but rejected as not cumulative. The SED contains a single conclusory statement regarding cumulative impacts: "Implementation of the proposed Policy will not result in cumulative impacts."[78] Yet the proposed Draft Policy would compel the installation of large cooling towers up and down the California coast and likely force the shut-down of several existing plants, leading to massive investment in transmission and replacement generation infrastructure. These reasonably foreseeable consequences of the proposed Policy would likely have incremental impacts that, when added to other closely related projects, will undeniably cause cumulative impacts in areas such as air quality, aesthetics, socieoeconomic consequences and greenhouses gases.

The SED failed to identify or analyze reasonably foreseeable environmental impacts of retrofitting existing OTC units with closed-cycle wet cooling. For example, the SED failed to reasonably analyze the greenhouse gas and other air emissions and the use of fresh water supplies for make-up water that will result from the implementation of the proposed Draft Policy, and the lack of reclaimed water infrastructure to serve these projects. The SED does not disclose or assess the availability of air credits, or the visual and aesthetic impacts of large cooling towers. The SED also does not fully consider the practical difficulty and feasibility, the regulatory hurdles, or the economic impacts of

[77] SED at p. 93
[78] SED at p. 108

constructing replacement transmission and generation necessary to offset the loss of the affected facilities.

Even where an agency is not *required* to conduct a project-level analysis, CEQA requires an environmental analysis to consider a reasonable range of environmental, economic, and technical factors, population and geographic areas, and specific sites.[79] In this case, however, the reasonably foreseeable potential environmental impacts of implementation of the proposed Draft Policy are not speculative or unknown. The proposed Policy would specifically target 19 identified facilities, contains strict implementation standards, few alternative compliance methods, and a rigorous schedule for compliance for each facility. Under these circumstances, CEQA requires a much more detailed, site-specific environmental analysis. Even as a programmatic document, the SED must take into account a reasonable range of site-specific factors.[80] A first tier environmental document must not defer all analysis of reasonably foreseeable environmental impacts.[81]

B. Alternatives

The SED does not consider a reasonable range of alternative policy options that could feasibly be implemented under Section 316(b) consistent with the Policy's goals. Indeed, as described elsewhere in our comments, there are numerous compliance alternatives that can legally and feasibly meet the requirements of Section 316(b) *and* avoid the significant environmental impacts associated with the Policy as currently proposed. CEQA requires that agencies refrain from approving projects with significant environmental effects, if there are feasible alternatives or mitigation measures that can

[79] Pub. Res. Code § 21159(c), (d).
[80] Pub. Res. Code § 21159.
[81] 14 CCR § 15152(b).

substantially lessen or avoid those effects.[82] The discussion of alternatives in an environmental document prepared pursuant to CEQA should evaluate the comparative merits of the alternatives and foster informed decision-making and meaningful public participation.[83] The alternatives analysis should contain facts and analysis, not just the agency's bare conclusions or opinions.

An environmental document must state the objectives sought to be achieved. The range of potential alternatives to the proposed project "shall include those that could feasibly accomplish most of the basic objectives of the project and could avoid or substantially lessen one or more of the significant effects."[84] The SED lists the goals of the Policy on page 14. The goals include: reducing impingement and entrainment, establishing technology-based performance standards that will implement CWA § 316(b), provide clear standards and guidance to permit writers, coordinate implementation at the state level to address cross-jurisdictional concerns, and reduce the resource burden on the Regional Water Boards. Not included is the goal that was stated orally by SWRCB staff at the September 16, 2009 hearing to force the shut-down of most OTC plants affected by the proposed Policy. Since this goal is neither a legitimate objective of Section 316(b) and was not included in the SED, it cannot be a basis for rejecting an alternative in the SED's analysis.

The SED failed to include a reasonable range of potentially feasible alternatives that achieve legitimate objectives of the Policy. For example, the SED did not consider whether to provide consistent state-wide guidance to the Regional Water Boards on the use of BPJ either in analyzing alternatives to a state-wide performance standard or in

[82] 23 CCR § 3780.
[83] 14 CCR § 15126.6(a), (b).
[84] 14 CCR § 15126.6(c).

alternatives to the wholly disproportionate standard. This is a logical alternative to include because it would actually reduce Regional Water Board workload, implement 316(b), and provide more flexibility to address cross-jurisdictional concerns and environmental impacts associated with forcing shut-down of the plants while still reducing impingement and entrainment. The SED also did not consider using the "significantly greater" test adopted by the EPA in its Phase II Rules and upheld by the U.S. Supreme Court in the *Entergy* case. Rather, the SED analyzes a narrower version of the "wholly disproportionate" standard alone, which applies to only a few facilities based on heat rate criteria that has no basis in the objectives of Section 316(b). The SED provides no justification for rejecting EPA's long-standing interpretation of reasonable standards under 316(b).

In other instances, the SED failed to provide a reasoned explanation for why certain alternatives were rejected, and failed to provide a discussion based on facts and analysis rather than bare conclusions. For example, the SED rejected the alternative requirement for low capacity units based on the incorrect assumption that all such plants have a greater environmental impact just because it is possible that they could be operated in certain ways. The SED contained no supporting facts or analysis of how these facilities actually operate. The SED also does not fully consider the importance of low capacity factor units to grid reliability and achievement of California's renewable portfolio targets. In another example, the SED rejects the alternative that would allow all plants to make the "wholly disproportionate" demonstration, incorrectly assuming it would increase Regional Water Board workload without analysis of its other comparative merits.

C. Procedural Issues

The Board failed to properly notice the availability of the SED. Under the Board's own regulations implementing CEQA, any standard, rule, regulation or plan proposed for Board approval or adoption must be accompanied by a written report analyzing the environmental impacts of the proposed activity, alternatives and mitigation measures.[85] Upon completion of the report, the Board shall provide a Notice of Filing of the report to the public.[86] The Notice must specify, among other things, the significant effects on the environment, if any, that are anticipated to result from the proposed activity.[87] The notice dated July 9, 2009, states that the "proposed Policy and supporting documents* are available on the State Water Board website." The asterisk referred to a statement at the bottom of the page: "The Substitute Environmental Document that supports the policy is projected to be available by July 15, 2009." Upon completion of the SED, the Board did not notice its availability nor specify the anticipated significant effects on the environment.

In addition, the Board failed to give adequate notice that the hearing on September 16, 2009 was to include environmental review. If an agency provides a public hearing on the project, environmental review should be expressly identified as one of the subjects for the hearing.[88] The SWRCB provided notice that the September 16, 2009 hearing was to be held to "receive comments on a proposed statewide policy on the use of coastal and estuarine waters for power plant cooling." The notice, however, gave no indication that the hearing also included comments on the SED.

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[85] 23 CCR § 3777(a).
[86] 23 CCR § 3777(b).
[87] Pub. Res. Code § 21092(b)(1).
[88] 14 CCR § 15202(b).

Section IV. The Scientific Portions of the Draft Policy and SED were not subject to peer review

The Board is required to submit the scientific portions of the proposed Draft Policy and SED, to the extent they support the conclusions and assumptions contained in the Draft Policy, to external scientific peer review.[89] A prior version of the Draft Policy was submitted for peer review, but the SED was not. The proposed Draft Policy and SED were not re-submitted to peer review follow substantial changes to the Draft Policy, and therefore the Board cannot take any action or adopt the final version until they are evaluated by external peer reviewers.[90]

Section V. Conclusion

For all the reasons given earlier in these comments, RRI believes that a reasonable OTC policy should be structured to meet the Section 316(b) requirements of the CWA consistent with federal guidance as upheld by the courts - not to implement an energy policy designed to shut down all but a select few of the OTC facilities. RRI has suggested a number of policy changes to that end. Of primary importance is establishing a policy that allows all of the individual facilities to cost-effectively minimize environmental impact; not one that requires achievement of the greatest possible reduction at a cost that is wholly disproportionate to the benefits of compliance. Furthermore, a reasonable OTC policy should not contain provisions that place the SWRCB in the position of establishing energy policy – the decisions on reliability and cost reside with the proper Energy Agencies. An OTC policy that incorporates the

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[89] Health & Safety Code § 57004(a)(2), (d) ("scientific basis" is defined to "mean those foundations of a rule that are premised upon, or derived from, empirical data or other scientific findings, conclusions, or assumptions establishing a regulatory level, standard, or other requirement for the protection of public health or the environment.").
[90] *Id.*

changes RRI has recommended will provide the appropriate balance between mitigating the environmental impacts of once-through cooling per the SWRCB's authority and maintaining electric supply and reliability in the State. RRI urges the SWRCB to adopt these recommendations.

Section VI: RRI Comments on the Draft Substitute Environmental Document

Sec. 1.3.3 Phase II Rule - 1.3.5 Current Status

The SED misinterprets the U.S. Supreme Court's ruling in *Entergy.* The question before the court was whether EPA could use cost-benefit analysis in determining BTA for a facility or for the industry as a whole in the face of a statute which was silent. Using long-standing rules of statutory construction, the court answered "Yes" to that question. The Court favorably noted that cost had been used in allowing a wholly disproportionate cost test for 30 years and that EPA's new cost "significantly greater than" test was also permissible[91]. The court also noted that EPA's interpretation of the statute is that it would be "unreasonable" to interpret 316(b) as requiring a facility to bear a cost of compliance wholly disproportionate to the environmental benefit derived.[92] Excerpts from the opinion are shown below:

> "[T]he Second Circuit nonetheless interpreted "best technology available" as mandating only those technologies that can "be reasonably borne by the industry." But whether it is "reasonable" to bear a particular cost may well depend on the resulting benefits; if the only relevant factor was the feasibility of the costs, their reasonableness would be irrelevant."[93]
>
> "We conclude that the EPA permissibly relied on cost benefit analysis in setting the national performance standards and in providing cost-benefit variances from those standards...[t]he Court of Appeals' reliance in part on the agency's use of cost-benefit analysis in invalidating the site-specific cost benefit variance provision was therefore in error..."[94]

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[91] *Entergy Crop. v. Riverkeeper, Inc.*, 129 S.Ct. 1498, 1504-1509 (2009) ("*Entergy*").
[92] *Entergy* at 1509.
[93] *Entergy* at 1510.
[94] *Id.*

Even those arguing against a cost-benefit test before the Supreme Court recognized that some comparison of costs and benefits is permitted.[95] Moreover, the SWRCB's own legal analysis of the decision notes that the Court found EPA's decision to use the more permissive "cost significantly greater than" test rather than "wholly disproportionate" test was legal.

The SED and the Draft Policy ignore the question before the Court and instead interpret the case as if the Court was asked whether cost-benefit analysis was required. Since the Court did not answer that question in the affirmative, the SED presumes that cost-benefit analysis is not a requirement and that BTA can be set at a level where few if any facilities can meet it. Even the minority opinion in *Entergy* noted that "[b]ecause we granted certiorari to decide only whether the EPA has authority to conduct cost benefit analysis, there is no need to define the universe of considerations upon which the EPA can properly rely in administering the BTA standard."[96]

The fact is that both the "wholly disproportionate" and "significantly greater" tests were upheld as lawful by the US Supreme Court. Under *Chevron*[97], deference is given to the body charged with administering the law. The EPA is charged with interpreting the CWA, and it has determined that it is unreasonable under the law to force existing facilities to incur costs significantly greater than the environmental benefit. The SED and Draft Policy provide no reasoned justification under the SWRCB's authority for why they are rejecting this test or the longstanding interpretation of section 316(b) by the EPA.

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[95] *Id.*
[96] *Entergy* at 1522 (J. Breyer, dissenting).
[97] Chevron U. S. A. Inc. v. Natural Resources Defense Council, Inc., 467 U. S. 837, 843–844.

In noting that there have not been significant changes in the regulatory environment for cooling water intake structures at existing facilities, the SED makes note of a 1977 U.S. EPA guidance document for assessing impacts pursuant to section 316(b). In dismissing the relevance of this guidance document, the SED notes that "this document is outdated…and does not capture the significant advances that have been made in cooling water intake technologies…." While the document may be more than 30 years old, it is still the policy of the EPA as it has not been withdrawn and should have been considered by the SWRCB. The document also contains no specific references to cooling water intake technologies and expressly states that "information is not provided on available intake technology" so it cannot be outdated for that reason.[98] Of particular note, this EPA 316(b) policy defines "cooling water intake structure" as "the total structure used to direct water into the components of the cooling systems," a point the Proposed Policy misses as it focuses on the cooling function instead of the intake structure.[99] The EPA 316(b) policy also notes the necessity to assess cooling water intake technology on a site specific basis. In several different instances within the EPA 316 (b) policy, the document stresses the necessity of making the assessment of best available technology on a site specific basis, a point the Proposed Policy refuses to acknowledge.[100] Neither of these points from the EPA 316(b) policy is outdated and should be incorporated within the SWRCB Proposed Policy.

[98] Draft Guidance for Evaluating the Adverse Impact of Cooling Water Intake Structures on the Aquatic Environment: Section 316(b), P. L. 92-500 (May 1, 1977) at 5.
[99] *Id.* at p. 17.
[100] *Id.* at p. 4, pps. 12 and 14.

Sec. 1.3.6 CEQA Analysis and Impact of Proposed Policy

At page 11, the SED states that site-specific impacts will be considered by the appropriate agency that is ultimately responsible for approving or implementing individual projects. But as explained in RRI Energy's comments, Track 2 is not feasible, and the policy does not allow for any reasonable variances for site-specific issues. Creating a Catch-22 is not a reasonable policy, and if the intent of the policy is to allow for site-specific issues (as is legally required) than the Draft Policy must be modified.

In addition, the SWRCB is required by CEQA to analyze a reasonable range of site-specific factors within the SED, even when preparing a programmatic environmental document.[101] The SED fails to analyze site-specific factors in a number of places, as discussed in detail below.

Sec. 1.6 Proposed Project and Description

At page 13, the SED mischaracterizes the Draft Policy when it states, "In limited circumstances, a facility may request alternative requirements if it demonstrates that the costs of compliance under Track 1 or Track 2 would be wholly disproportionate to the benefits to be gained." There are **no** circumstances in which the vast majority of the affected facilities can request alternative requirements under the Draft Policy. While the Draft Policy should be changed, this statement should be changed to accurately describe the Policy as proposed – only a very limited number of facilities may seek such alternate requirements based on criteria that have nothing to do with water quality or impacts on marine life.

The SED notes that the Draft Policy would establish an advisory committee made up of the Energy Agencies and certain other environmental agencies to assist the

[101] Pub. Res. Code § 21159(a)(1), (c).

SWRCB as it establishes plans and to "prevent disruptions to the State's electrical supply." It is not clear how the SWRCB, which lacks legislative or budgetary authority, expects to require these other agencies to participate. Who is to pay for these meetings and reports? Is it in these agencies' budgets? What obligates an independent agency to participate? When did the SWRCB become responsible for preventing disruption to the State's electrical supply? The SED should have included such information to allow the public to understand the effects and reasonably foreseeable impacts of the proposed Policy, including the possibilities that funds may not be available for a particular agency to participate or an agency may decline to participate in the future.

Sec. 1.7 Statement of Goals

The goals listed in the SED do not include the goal to shut down the steam boiler OTC units, which was stated as a goal by SWRCB staff at the September 16, 2009 hearing.[102]

Moreover, the SED does not explain how the stated goals will be achieved. For example, there is no information to indicate the Draft Policy would either reduce the workload of the Regional Water Boards, or improve the consistency of their decisions.

Sec. 2.2 Biological Impacts

At page 28, the SED statement that "the ongoing fish kills from the OTC plants essentially constitute a de facto "take" permit from the State's coastal waters" is inflammatory and unsupported. It appears to rely on a conclusory statement from the CEC that such plants were partly responsible for ocean degradation. However, the CEC

[102] At the September 16 public hearing, senior State Water Board staff stated that these plants are 40 to 50 years old, so they should shut down – "we don't want closed cycle cooling slapped on these old power plants."

is not an environmental agency capable or authorized to make a "take" determination. The SED also references the Phase I and Phase II record at USEPA as support for this statement, but it fails to note that the EPA did not find this a justification to establish closed cycle cooling as BTA for existing OTC facilities.

The tables on impingement and entrainment (IM/E) show that 6 plants account for ~90% of the IM/E problem.[103] Why then is the focus of the Draft Policy to force the retirement of the other OTC plants? If the purpose of the policy was to minimize adverse environmental impacts on California's coastal waters as Section 316(b) of the CWA calls for, then clearly the IM/E impacts of the individual or closely-situated OTC plants should have been a consideration. RRI commissioned an independent biologist to review the IM/E data at Mandalay and Ormond Beach and he found that their operation does not significantly contribute to the decline of local fish populations.[104] In fact, he found that the greatest factor contributing to the recent declines in the southern California fish populations is the change in seawater temperatures due to an "El Nino" like water circulation pattern of the northern Pacific. The same may be true for other OTC plants with intake waters located in the Southern California Bight.

The SED fails to include information supporting its assumptions that all OTC plants --contribute to decline of fish populations. Furthermore, it appears this information does not exist and that the Draft Policy was developed without that

[103]SED Table 2. Estimated Annual Entrainment and SED Table 3. Estimated Annual Impingement at 31, 32
[104] "Biology of fish species entrained at two Ventura County Generating Stations," Thomas B. McCormick (September 2009) at p. 3

information as the SED indicates that a future study is needed on the cumulative effects of all the closely situated plants.[105]

Sec. 2.4 Status of OTC plants

In the SED's discussion of the status of the OTC plants, acknowledgement is given to the value of the OTC plants, specifically: "the fleet of OTC power plants are essential to the overall reliability of the grid, especially in light of the fact that the State's demand for electricity is increasing."[106] Furthermore, the Energy Agencies have also made statements regarding the value of OTC plants for local reliability and as a bridge as the State transitions to an increased reliance on renewable energy in the state. Yet, the Draft Policy, although developed with input from the Energy Agencies, has the potential to force the majority of the OTC facilities into premature retirement. There is a clear disconnect between the Policy's outcome and the important role these plants play now and in the future for maintaining the reliability of the electric grid.

Sec. 2.71 Combined Cycle Generation

While combined cycle power plants are relatively more efficient in producing energy, they are less cost-effective for providing ancillary services, since combined cycle plants may incur a maintenance cost penalty for cycling, while steam units can ramp at rates of up to 30 MW/minute and do not incur any significant increase in maintenance costs from cycling up and down within an operating day, as may often be required to follow load and integrate intermittent renewable energy.

[105] SED at p. 33.
[106] SED at p. 37

Combined cycle plants are no more efficient than steam units in providing firm capacity necessary to assure reliable operation of the electric grid. The CAISO's Resource Adequacy program places the same value on capacity from resources with similar availability rates, without regard to whether the unit is a steam turbine or combined cycle configuration.[107]

The SED mistakenly assumes the thermal efficiency is the only important criterion for evaluating the relative value to the grid of steam units as compared to combined cycle units, and further mistakenly concludes that impacts measured on an energy basis are appropriate. The following table illustrates, by extending Table 9 from the SED to demonstrate that in terms of CO2 emissions per MW of capacity, the non-combined cycle units are substantially more efficient, imposing less CO2 emissions per MW than combined cycle facilities.

Comparison of Steam Boiler and Combined Cycle Efficiencies					
	Efficiency (percent)	CO2 (tons/yr)	CO2 (lbs/MWh)	*Capacity (MW)	CO2 (lbs/MW)
Non-Combined Cycle Units	35	8,327,338	1,323	14689	567
Moss Landing Unit 1 (1A/2A)	50	1,152,071	837	540	2,133
Moss Landing Unit 2 (3A/4A)	50	1,153,289	832	540	2,136
Haynes Unit 8 (9/10)	50	1,026,193	834	575	1,785
* From SED Table 10 - Non combined cycle units excluding SONGS and Diablo Canyon					

Sec 3.1: Should the State Water Board adopt a statewide policy?

The SED recommends a statewide policy, arguing it achieves consistency among the Regional Water Boards and is less burdensome to the agency's staff.[108] The SED

[107] Under the CAISO Tariff, the CAISO tracks the availability of Resource Adequacy Capacity during the Availability Assessment Hours of each month, in order to determine the amount of Resource Adequacy Capacity that was available to the CAISO. Each Resource Adequacy Resource is subject to Availability Standards beginning in 2010, and Non-Availability Charges or Availability Incentive Payments are specified based on performance against this standard. Combined cycle units and steam units are subject to the same rules.. (California Independent System Operator, FERC Electric Tariff, Section 40.9).
[108] SED at p. 14

acknowledges that use of BPJ allows for "more consideration of site-specific issues" but asserts that it is more costly and labor-intensive to the agency. However, the Regional Water Boards have been making site-specific "Best Professional Judgement" (BPJ) determinations for many years, so they already have the expertise and resources necessary to make site specific BTA evaluations. The SED erroneously over-simplifies the state of the coastal environment, feasible intake structure technology, geographic locations, and other local concerns (legal, social, and economic) when it asserts that there is "relative similarity between most facilities." It also fails to provide any evidence that the proposed policy will either achieve greater consistency or reduce the burden of the BPJ permitting process.

The proposed statewide Policy will result in enormous adverse environmental, economic and social impacts to the State and should not be justified on the primary bases that it is needed for statewide consistency and will be less burdensome to the Regional Water Boards' staff. Consideration of site-specific factors is exactly what is required to properly balance protection of water resources with other State goals and policies. Consistent statewide guidance to the Regional Water Boards on the use of BPJ would be both effective and appropriate – and would be consistent with the approach used in every other State in the country addressing once through cooling. This would also have the effect of reducing the workload for the Regional Water Boards' staff.

<u>Sec 3.2: How should new and existing power plants be defined?</u>

The Policy recommends using EPA's definition and distinction between new and existing facilities and RRI concurs.

Sec 3.3: Should the Policy distinguish between nuclear and fossil facilities?

The Policy recommends that nuclear facility owners fund 3rd party feasibility assessments to evaluate alternatives due to their significance to the electric grid. The Policy should permit all facility operators to demonstrate the applicability of cost effective alternatives to minimize impacts through the use of wholly-disproportionate cost criteria.

Sec 3.4: Should alternative requirements be established for low capacity utilization facilities?

The Policy concludes that, since there are seasonal variations in larval fish, it is possible for facilities with low capacity utilization rates (<15%) to have a greater impact than facilities with higher utilization rates. No evidence is presented to demonstrate that specific low capacity utilization rate units are actually having an adverse environmental impact. The Policy should recognize that facilities with low utilization rates inherently have reduced total flow and hence reduced IM/E (IM/E) impacts. The Policy should allow such facilities to take credit for the reduced IM/E impacts as a result of their current and projected operating rates. Appropriate conditions could be placed in a facility's NPDES permit to ensure the reduced IM/E impacts are maintained.

The Proposed Policy would offer certain units an alternate compliance track if costs are demonstrated to be wholly disproportionate to benefits – but this alternate track is only offered to nuclear units and combined cycle units. Instead of allowing low capacity factor units to comply with alternative requirements as would have been established under the EPA Phase II rules, the proposed policy would deny these low capacity factor units the opportunity to comply using an exception offered to base load units with many more operating hours. Since pumps are running during all operating hours, baseload units use more seawater, and generally impinge and entrain more marine life. In general, the more operating hours, the greater the impacts on marine life.

Since combined cycle units are slightly more fuel efficient, SWRCB staff concludes that the environmental harm is less significant as compared to a slightly less efficient steam generator. But harm to the environment does not occur based on heat rate, it occurs based on the IM/E, which the SED assumes to be proportional to gallons used. The reality is that the lower heat rate units run more, use more cooling water and impinge and entrain vastly more fish, eggs, and larvae than the steam boiler units. For instance, the Moss Landing combined cycle units (Moss Landing 1 and 2) have a rated capacity of 1080 Mw compared with Ormond Beach at 1612 Mw.[109] Yet Moss Landing 1 and 2 entrain ten times more larvae than Ormond Beach annually (311 million larva vs. 32 million).[110] The numbers are even more disparate for fish impingement (57,000 for Moss Landing 1 and 2 compared to 517 for Ormond Beach).[111] Although the larger plant (Ormond Beach) with the somewhat higher heat rate actually entrains one tenth the number of larva and impinges one one-hundredth the number of fish, the SED chooses to deny that plant the opportunity to use a wholly disproportionate cost variance while allowing that opportunity to the plant with greater environmental impacts. This simply makes no sense if the purpose of the policy is to minimize the adverse environmental impact on coastal waters. It only makes sense if the goal is to force retirement of steam boiler generation in California, and that is not a reasonable basis for a state-wide water quality control policy enacted by the SWRCB.

[109] SED Table 4 at pp. 34, 35
[110] SED Table 2 at p. 32
[111] SED Table 3 at p. 32

The SED dismisses Alternative 1, which would establish an alternative requirement for low capacity factor units, with the non-sequitar that it is possible to operate less than 15% of the time and cause a greater impact than would be assumed if entrainment was uniform at all times. While that may be true, it is specious reasoning to then leap to the conclusion that a low capacity factor unit could have greater impact than one that operates baseloaded. *Ceteris parabis,* a higher capacity factor unit will operate during the same hours that the lower capacity factor unit is operating – plus many more hours when it will be entraining and impinging aquatic life while the low capacity factor unit is off-line and not pumping any seawater. The statement that "data show that it is possible to operate less than 15% of the time and cause greater impact than would be assumed if entrainment was uniform at all times" has no basis and should not be the rationale for rejecting alternative requirements for low capacity factor units.

<u>Sec 3.6 What constitutes BTA for existing power plants?</u>

The preface states that *Entergy* did not address whether 316(b) could be implemented without first considering the extent of any impact before determining BTA and that BTA can be established without cost-benefit analysis. The Supreme Court said that the EPA interpretation that BTA decisions include cost-benefits test was lawful. Thus, the current state of the law is that USEPA has been upheld in using cost-benefit tests and in finding that it is unreasonable to impose costs significantly above benefits. That is hardly the same as arbitrarily deciding that benefits do not need to be considered, as the SED claims.

The Draft Policy and the SED designate wet cooling towers as BTA without reasoned consideration of the costs involved or the benefits to be derived. Installing cooling towers on existing power plants with low capacity utilization rates will result in costs not only significantly exceeding benefits, but in costs that are wholly disproportionate to the benefits of installation. The Policy must follow precedent set by the EPA and the courts by allowing all facilities to consider the costs and benefits when determining what constitutes BTA at a specific site.

With regard to the SED's justification for finding cooling towers as BTA, it relies chiefly on the Tetra Tech report. This report found that at 12 of 15 facilities studied it was physically possible to install cooling towers, while it was infeasible at 3 facilities and thus not available. By definition, cooling towers are not the best technology available for these three facilities yet the Policy did nothing to establish what is the BTA for these facilities. Further, the SED provides no way for the three facilities to comply, because they are all low capacity factor steam plants that do not qualify for a variance. This is arbitrary and capricious, because what is unavailable cannot be BTA.

SWRCB's staff brushed this concern aside by relying only on the cost reasonably borne by industry test. Analysis of the cost reasonably borne test, however, does not support adoption of cooling towers as BTA. Staff gives no indication of what is reasonable and simply assumes that the Tetra Tech annualized cost numbers are reasonable.

Tetra Tech assumed the cost would be recovered over a 20 year life, yet the SED continually harps on the age of these units and their inefficiency. Given that RRI's units are not projected to have to comply until 2020, is it reasonable to believe that they will be recovering the cost of BTA in 2040, over 30 years from now? The answer is of course not, and a reasonable amortization period would not be greater than 10 years at most. In any case, even using a 20 year amortization period, the cost increase is 1.45 cents per kWh for the fossil steam units and it is 1.13 cents per kWh for all the OTC units. The average wholesale price in 2006 was 4.7 c/kWh, so this means the annual cost of cooling towers using a 20 year amortization rate is 24% of the total wholesale cost for all units and 31% for the fossil steam units. This is in excess of the return on investment of those units and in the case of many fossil steam units is much greater than revenues after subtracting fuel costs. That is not a cost reasonably borne by industry

The comparison gets worse assuming a 10 year amortization. In that case the cost of cooling towers for the steam boiler units is 2c/kWh, or 47% of the 2006 wholesale price. There is no basis to assume these are costs reasonably borne by industry.[112]

In this section, the SED characterizes the Track 2 approach as being no less than 90% of the reduction in Track 1. This is an inaccurate statement because the baseline changes between the two Tracks. Track 1 uses an instantaneous design flow rate while Track 2 uses an actual average flow rate over a year. These are dramatically different baselines. For low capacity factor units, requiring an 83% reduction from actual average flow is actually a stricter standard than a 93% reduction in instantaneous flow. This is why Track 2 is illusory for these units, something the drafters of the Policy either did not understand, or understand all too well.

Furthermore, under Track 2, a facility can use either technological or operational options to comply. Credit is given to technological changes installed prior to the

[112] Note that the correct costs to use are in the right hand column on Table 12, labeled "Cost per kWh. The units are incorrectly labeled in that column, however, as they are actually cents/kWh, not dollars per MWh. The units are correctly noted in the text immediately preceding the table in the SED. The SED also includes a hypothetical calculation of costs if all of the units ran all of the time, labeled Cost per kWh (capacity)." This column of data provides no worth as the units do not run all the time, have never run all of the time, and will never run all of the time because of the fundamentals of electric demand and existing supply. It is unreasonable to rely on the data in this column for decision-making.

adoption of the Policy, but not to operational options. But if operational options (i.e., running less) can qualify as BTA going forward, why do they not qualify retrospectively? The SED is silent on that question. It is unreasonable to make that distinction however, and Track 2 should be modified to allow lower run hours to qualify as BTA regardless of when the lower run hour regime started.

Finally, the decision to use 0.5 fps through-screen intake velocity as an impingement mortality performance standard has no basis in the record and otherwise does not comply with CEQA. The SED's only basis for the standard is the EPA's Phase I rule which relied on a single study conducted in 1973 and a safety factor developed based on three additional fish swim studies.[113] The SED does not properly incorporate these materials by reference. CEQA requires that materials incorporated by reference must be made available for inspection and the environmental document must state where that inspection may take place, describe its relationship with the incorporated portion of the referenced documents, briefly summarize the incorporated materials, and briefly describe the relevant data or information.[114] Therefore, the documents discussed in the EPA's rule cannot support the Draft Policy's recommendation. In addition, it is not appropriate to incorporate materials by reference in order to provide the only analysis of an issue.[115]. At a minimum, the SWRCB should have cited and described the studies relied on by the EPA and conducted a search of recent literature on the issue to determine whether recent information supports or undermines the EPA's analysis.

The SWRCB also failed to analyze any alternatives to the impingement mortality performance standard, such as another number for through-screen velocity or another

[113] SED p. 57, *citing* 66 FR 65274.
[114] 14 CCR § 15150(d).
[115] *See* 14 CCR § 15150(f)

type of measurement like an approach velocity. In addition, the SWRCB did not consider any alternative compliance levels, such as a different impingement reduction measure for Track 2 compliance. The BTA alternatives considered in the SED only involve the entrainment reduction standard

Sec 3.7: How is the Track 1 entrainment performance standard calculated?

The staff recommends using a 93% reduction in intake flow at all sites. This minimum reduction target is based upon the selection of wet cooling towers as BTA. The staff cites the elimination of "the need to conduct site-specific retrofit evaluations" as one of the benefits of this approach.

As noted in comments on Sec 3.6, wet cooling towers should not be the prescribed BTA. Furthermore, a site-specific retrofit analysis is precisely what is needed to determine cost-effective, feasible means to minimize IM/E impacts. Again, Track 1 is an illusory compliance option which will be infeasible at virtually all sites. As already noted, SWRCB staff said on the record at the Public Hearing that they do not even want these units to install cooling towers. How, then, can it be BTA?

The SED did not provide any discussion or reasons for rejecting Alternative 1.

Sec 3.8: What baseline monitoring should be required?

The staff recommends that IM/E monitoring would be conducted in association with each NPDES permit renewal to provide a baseline but does not justify why additional data must be obtained and how it would be utilized.

Most facilities have accumulated years of monitoring data as required by their NPDES permits as well as recent monitoring pursuant to the EPA Phase II rule. This monitoring has been conducted at considerable expense. These data can be extrapolated to represent the estimated IM/E levels over a range of a facility's projected operating levels to assist in establishing a baseline.

Assuming a facility has met the Track 2 compliance target based upon previous IM/E monitoring, what assurance would that facility have that it could continue to operate if new sampling data indicated IM/E levels had increased? Would this result in denial of the NPDES permit renewal? If so, the facility would suddenly be faced with closure within a very short timeframe. Again, all of these decisions are to be made in an unspecified way "to the Regional Water Board's satisfaction".

Sec 3.9: What monitoring requirements should be included?

The staff is recommending that those entities utilizing Track 2 compliance would perform IM/E monitoring to verify the measures taken have enabled the facility to achieve Track 2 compliance levels. The scope, duration and frequency of the monitoring are, again, at the discretion of the Regional Water Board. Post-implementation compliance monitoring should only be required once to verify compliance.

Sec 3.10: Should a makeup water source be specified for Track 1?

The staff recommends that power plant owners utilizing Track 1 be required to consider the feasibility of using reclaimed water as a makeup water source to wet cooling towers. The staff acknowledges that increasing demand for reclaimed water might impact the availability of such water.

The SED does not specify what criteria would be applied to determine if a reclaimed water source was available or feasible. In many power plant locations, a reclaimed water infrastructure is not in place. Where plans for an infrastructure are underway, those plans do not automatically include service to intermittent users, such as power plants operating at low capacity utilization rates. Failure to develop criteria for this evaluation could lead to Regional Water Boards requiring a power plant owner to fund development of a reclaimed water infrastructure or rely on speculative development plans.

Sec 3.11: Should the Policy include a statewide compliance schedule?

RRI believes that BTA should be set such that it is achievable. If that is done, this section becomes moot. RRI's comments in this section will assume however, that the Draft Policy has not been changed.

The SWRCB should not adopt a Policy that specifies dates when individual power plants should retire from operation. Electric policy is the bailiwick of the legislature, the Energy agencies, NERC and FERC Reliability and cost determinations should not be considered "advice" which the State or Regional Water Boards merely have to consider but not adopt. Inclusion of highly speculative and uncertain retirement dates into a facility's NPDES permits, making them legally enforceable requirements, is not sensible or reasonable.

Under the proposed policy, almost all units lack a viable compliance path, and will be shut down when the compliance date is reached, despite the fact that required replacement transmission and generation infrastructure essential to maintain the integrity of the electric grid has yet to be identified. By fixing dates for compliance, the SWRCB is further asserting authority over the integrity of the electric grid, and creating a mandate for entities obligated by law to assure the reliable operation of the electric grid to petition the SWRCB and seek an extraordinary change in water policy if the completion of necessary studies, permitting, construction and operation of replacement electric infrastructure does not coincide with the compliance dates the SWRCB has selected.

Before the SWRCB approves a policy with fixed compliance dates, substituting its authority for that of entities responsible for the reliable operation of the electric grid, it should verify that:

1) The federal Department of Homeland Security concurs that such a policy would in no way compromise the security of the Nation's critical electric infrastructure or violate the intent of Homeland Security Presidential Directive-7;[116] and

2) The North American Electric Reliability Corporation (NERC) and Federal Energy Regulatory Commission concur that the SWRCB's policy does not conflict with any mandatory and enforceable NERC Reliability Standards.[117]

Alternatively, the SWRCB could eliminate the fixed compliance dates from its policy, and instead allow the Energy Agencies to proceed with the process described in their proposal, and once reliability designations are lifted from individual generating units, the NPDES permits can be modified to include fixed compliance dates.

It must also be noted that the SACCWIS is a completely untested process for evaluating electric reliability and cost. It attempts to create an informal umbrella over the processes in place at other agencies. The SED should evaluate the legality and enforceability of this umbrella process, as well as exploring the foreseeable circumstances of implementing an inflexible process onto an ever-changing electric grid, and the unintended consequences that fixed compliance date could have on investment at the existing OTC plants and hence grid reliability.

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[116] Homeland Security Presidential Directive 7: Critical Infrastructure Identification, Prioritization, and Protection, available at: http://www.dhs.gov/xabout/laws/gc_1214597989952.shtm#1

[117] NERC Reliability Standards are available at: http://www.nerc.com/files/Reliability_Standards_Complete_Set_2009Sept14.pdf

Sec 3.12: Should the Policy include interim requirements?

The use of exclusion devices where applicable is a cost-effective means to minimize impingement of large aquatic organisms. Many plant operators are not running intake pumps when the facility is not generating electric power due to the costs of running the pumps. Allowing for pump operation during facility startup, shutdown and standby conditions is necessary and appropriate.

We agree with the staff that restoration is a valuable means to offset IM/E impacts. We further agree that the effectiveness of restoration is inherently site-specific. Flexibility in the selection of restoration options is essential. The effective use of restoration however, requires establishing specific criteria for the Regional Water Boards to use in assessing restoration proposals. The criteria should be developed through a public stakeholder process to ensure goals and expectations are realistic and not cost-prohibitive.

We wish to offer specific comments on data presented in Table 18 on SED page 76 regarding RRI's facilities listed:

1) The Ormond Beach facility currently has a 14" exclusion device as opposed to the 18" grid listed.
2) The Mandalay facility intake is not a shoreline structure but is located at the end of a 2.5-mile long canal originating at the Channel Islands Harbor in Oxnard. Reducing the amount of water utilized by the facility may result in stagnant water in the canal: a reasonably foreseeable impact that was not considered in the SED.

Sec 3.13: Should the Policy include a wholly disproportionate cost-benefit test?

The staff states that it selected the BTA of Track 1 and 2 using a "reasonably borne" cost analysis. However, no description of that analysis or data is presented to demonstrate it has any applicability to the facilities affected by the proposed Policy. The staff correctly notes that "the possibility that the Track 1 or Track 2 compliance costs might be unreasonable compared to overall benefits."[118] This is exactly the scenario the Supreme Court indicated was not intended by the Clean Water Act. Consequently, the SWRCB must provide an opportunity for every facility affected by the Proposed Policy to be eligible for an alternate compliance plan if they can demonstrate that costs are wholly disproportionate to benefits.

The SED claims that it is not possible or feasible to evaluate each facility's ability to comply with the performance standards, yet this is precisely what the Tetra Tech Study attempts. This study finds cooling towers infeasible at Ormond Beach and two other sites. It comes up with cost per MWh of compliance for almost all of the other facilities. For instance, Mandalay has a nearly 2 c/kWh cost of compliance, while if the towers were feasible at Ormond Beach, the cost of compliance is estimated at 3 c/kWh. These are both a great deal higher than the average assumed in the SED, which is driven lower by the inclusion of the combined cycle units.

The SED states that if all facilities were allowed to use a wholly disproportionate cost test, they would likely do so, requiring a site-by-site application of Best Professional Judgment, and negating the benefits of a coordinated statewide policy. There is nothing that prevents the SWRCB from developing consistent statewide guidance on the application of Best Professional Judgment and other criteria to the Regional Water Boards so that standards are applied uniformly. In addition, this statement is also a testament to the fact that Tracks 1 and 2 compliance as proposed are impossible.

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118 SED at p. 80

The staff recommends that fossil fueled facilities with a heat rate of 8500 or less be allowed to utilize a wholly disproportionate cost test because those facilities are more thermally efficient than older steam boiler plants. No evidence is presented to justify how this position minimizes aquatic impacts, other than the assertion that these facilities have a lower water demand on a per MWh basis. As explained in RRI's comments in Section 3.4, low capacity factor units are likely to have lower IM/E impacts than those that qualify for this variance.

Moreover, the staff's proposed discrimination against steam units is based on the mistaken assumption that the value of electric generation is in the energy produced. This ignores the value of capacity, which is the ability to produce energy. The low capacity factor OTC units have the same capacity value, kW for kW, as base load units under the Resource Adequacy program administered by the CAISO. A more appropriate index for the purpose of determining environmental harm in relation to a unit's value to the electric grid might be the number of operating hours or gallons of seawater pumped per MW of Resource Adequacy capacity. The low capacity factor steam units would demonstrate lower impacts on marine life by this index, as explained in comments on Section 2.7.1.

Also, the reasoning that the variance should be provided for plants with 8500 heat rate and below because of air impacts is not accurate. Later in the SED the data demonstrates that the Draft Policy actually increases emissions, including for CO2, by double digit percentages.[119] What matters is actual emissions based on how plants actually operate, not emission rates per MWh with the implicit assumption that all plants

[119] SED Table 23 and Table 24 at p. 98.

operate the same. Thus, emissions rates per MWh cannot reasonably be a basis for granting a variance.

Finally, the SED inaccurately states that the compliance costs are uniformly higher, on a per MWh basis, than for non-nuclear-fueled units.[120] In fact, the compliance cost for steam boiler units are uniformly higher and have the highest cost of compliance per MWh. The SED cherry-picks when to combine steam boiler units with combined cycle units (as it does here) in order to give an exclusion to nuclear units, and when not to consider them together as it does on the 8500 heat rate exclusion. This is arbitrary, goal-oriented decision-making.

There is no reasonable basis for denying any unit the ability to demonstrate that costs are wholly disproportionate to benefits.

Sec 4.3: Aesthetics

The staff states that it did not identify any significant aesthetic impacts of installing cooling towers at any of the sites utilizing once through cooling because the sites are already in developed areas. While that may be the case at some locations, installing the large cooling towers required for closed-cycle cooling would cause aesthetic impacts at many sites that the SED does not discuss.

While cooling tower structures will be similar to other structures at or in the vicinity of the facilities, the plumes will create a visual impact more significant than the facility structures themselves. As one example, RRI's Ormond Beach facility in Oxnard is located only 2.5 miles west of the Point Mugu Naval Air station, whose flight

[120] SED at p. 83

operations could easily be impacted by a cooling tower plume.[121] Plume-abated towers might provide some mitigation, but such towers would be even larger and thus have even greater impact.

Aesthetic impacts must be assessed on a site-specific basis and should include input from the responsible local jurisdictions regarding the likelihood they would ever approve of such an installation.

Sec 4.4: Agricultural and Forest Resources

The staff did not identify any significant agricultural or forest impacts, based in large part on a study by Tetra Tech that assumed high efficiency drift eliminators would be installed on any wet cooling towers. Drift eliminators will increase the cost of the wet cooling towers and there is no basis to assume they would be included on all wet cooling towers.

Sec 4.5: Air Quality

The staff correctly notes that the installation of wet or dry cooling towers will cause a decrease in power plant efficiency and hence a decrease in electric power capacity. The lost energy capability will have to be provided by the increased generation from other fossil-fueled facilities, thereby increasing air emissions.

If all facilities installed wet cooling towers, California could experience, by the staff's own estimates, a 13% increase in Particulate Matter emissions, a 15% increase in SO_2, a 17% increase in carbon monoxide and an 18% increase in the ozone-precursor NO_2. Such increases in air emissions will be problematic for air districts already struggling to meet air quality standards. The staff suggests that these increased emissions

[121] SED at p. 58

could be mitigated by the installation of emission controls but these opportunities are limited since most air districts are already requiring facilities to meet BARCT and BACT control levels. The staff concludes that it cannot accurately assess the air quality impacts of the Policy because it is too difficult to estimate the method of compliance.

Also, the inclusion of Scenario 3 and Table 25 is an unreasonable basis for decision-making. Dry cooling, assumed to be installed in this scenario, is not the BTA criteria proposed to be adopted. This scenario assumes that all of the fossil-fuel OTC units are torn down and replaced with dry-cooled combined cycle units. What this has to do with the Draft Policy is a mystery that is unexplained in the SED, but it is unreasonable to use in any analysis of the reasonably foreseeable environmental impacts of requiring wet cooling as BTA.

Because the SED fails to consider a reasonable range of site-specific factors in its analysis of the Policy's impacts and fails to consider the impacts of all reasonably foreseeable methods of compliance, the potentially significant air quality impact of this Policy is unknown. Given the air quality challenges the State currently faces, a Policy that could result in significant increases in pollutants warrants a more detailed assessment.

<u>Sec 4.6: Greenhouse Gases</u>

The staff correctly notes that the installation of cooling towers will result in a net increase in carbon dioxide emissions. The retrofitting of cooling towers will cause a loss of thermal efficiency, requiring the lost electric generating capability to be provided by other facilities. This electric power will need to be provided by other fossil-fueled facilities, thereby increasing their total CO_2 emissions.

The SED estimates that if all facilities were to convert to wet cooling towers, the net increase in carbon dioxide emissions could total 1,237,259 tons! This is equivalent to adding over 300,000 additional cars to California's highways.

The staff notes that these estimates vary depending on whether facilities install wet or dry cooling towers, repower or replace the facility. But the only case that reduces emissions is the unsupported one that assumes all non-nuclear units are destroyed and replaced with dry-cooled combined cycles. The two plausible cases have increases greater than 10%. The staff then makes the completely unsupported assertion that the net increase in carbon dioxide is expected to be between zero and 5% of its worst case scenario.[122]

The SED has not adequately addressed the potential environmental impacts of this Policy relative to CO2 emissions or the Policy's impact on the State's efforts to meet aggressive GHG reduction goals.

Sec 4.7: Noise

The SED failed to analyze the reasonably foreseeable effects of the policy on noise resulting from construction of new facilities to meet the revised standards. The SED also did not consider other effects of construction due to implementation of the policy.

Sec 4.9: Water Quality

The staff concludes that water quality impacts as a result of the Policy will not be significant on the basis of examining three (3) facilities and the irrelevant assertion that

[122] SED at p. 102.

these facilities already face other water quality challenges. Other facilities were not assessed at all.

Again by virtue of the fact that the SED does not analyze a reasonable range of site-specific factors, the SED makes broad, unsupported conclusions. Wet cooling towers will concentrate nonvolatile constituents in the cooling water loop, jeopardizing the ability of the facility to discharge blowdown water under its NPDES permit. This will make the installation of wet cooling towers infeasible.

The staff indicates new dilution models will need to be developed to accurately estimate compliance with effluent limitations, inserting yet another major uncertainty in the feasibility of the staff BTA selection, wet cooling towers. If further wastewater treatment is required, costs of compliance will escalate even further.

Sec 4.10: Utilities and Service Systems

The SED relies on the Jones and Stokes report alone. The SWRCB should confirm that analyses performed by the Energy Agencies, and in particular the CAISO support the conclusions in Section 4.10 of the SED. In some cases, the statements from this section are consistent with available information, and elsewhere beg additional analysis by the Energy Agencies, as shown below.

1. *Modeling shows that the electric industry could compensate for mass OTC retirement at "relatively modest costs to the ratepayer."* However, Tetra Tech numbers from Table 2 show wholesale costs would need to go up 24%-30% which any reasonable standard is a significant change. The lowest cost case from the Jones and Stokes report is the case where the OTC plants do not retire. Operating the OTC plants is millions to hundreds of millions of dollars cheaper than repowering or converting to wet cooling.

2. *Under all but the most extreme scenarios, more than enough power plants are expect to be operating to more than compensate for any or all OTD plant retirements.* This is simply inconsistent with the Energy Agencies' Joint

Proposal, provided in Appendix C to the SED, which makes clear that no facilities can be retired without some additional transmission or generation infrastructure. The Joint Proposal also lays out a comprehensive process and schedule for additional study that Section 4.10 of the SED ignores.

3. *The state seems well-poised to compensate for most OTC plant retirements in the 2012 and beyond time period by constructing transmission upgrades to tap into the excess generating capacity projected to occur then.* The CAISO has estimated that the cost of transmission upgrades for the L.A. Basin alone may be $4.45 billion or more,[123] and SCE estimated that replacing once through cooled capacity would likely take "decades" rather than seven to nine years as assumed in the draft policy.[124]

At the public hearing, the CPUC representative, Robert Strauss recommended that the SWRCB consider the cost impact of the Draft Policy, noting that replacing cooling systems will be "very expensive" and that the cost and environmental impacts of alternative power supplies may be high – meaning that the policy may impose billions of dollars of costs on customers. These are not "modest" costs, and a much more complete analysis of the cost impacts on electric customers – and whether the benefits of the policy justify such enormous costs – must be completed to comply with the economic analysis requirements of CEQA.

Sec 4.12: Cumulative and Long-Term Impacts

After merely stating the definition of cumulative impacts and describing the purpose of assessing cumulative impacts, the SED concludes that the Policy "will not result in cumulative impacts". This conclusion is totally unsupported and does not include whether any impacts were considered but rejected as not cumulative.

[123] See "Impacts on Electric System Reliability from Restrictions on Once-Through Cooling in California", page 21, available at http://www.caiso.com/208b/208b8ac831b00.pdf
[124] See comments by SCE Executive Vice President Pedro Pizarro at page 45 of the transcript for the CEC's July 28, 2009 workshop on once through cooling, available at: http://www.energy.ca.gov/2009_energypolicy/documents/2009-07-28_workshop/2009-07-28_TRANSCRIPT.PDF

In locations where power plant facilities are in close proximity to each other, there are likely to be cumulative environmental impacts. These could include aesthetic, water use and local grid reliability impacts. There is no basis for the SED to conclude that there will be no cumulative impacts as a result of the Policy. While cumulative impacts will be considered in later site-specific environmental analysis, the SED must not defer all analysis of the Policy's cumulative impacts to future project-level reviews.

5.0 Economic Analysis

The SED states that the cost of compliance is 0.45 c/kWh based on collective generating capacity. [125] As explained before, that is a nonsensical calculation that assumes 100% operation. The annual cost of compliance divided by 2006 annual generation averages 1.13 c/kWh and ranges from 0.2 c/kWh at the combined cycle units to almost 7 c/kWh at one of the steam units.

One should then compare the correct compliance cost to the wholesale price, to determine whether the cost are reasonably borne, because that is the price these units receive. That price was 4.7 c/kWh in 2006, making compliance cost 24% of price on average and a good deal more than that for the conventional steam boiler units.[126]

Ultimately what really matters for the wholesale industry is not the wholesale price, but revenues after fuel costs. These are the net revenues that are available to cover operations and maintenance expense, capital additions, and a return of and on capital. Using Tetra Tech's own numbers for gross revenues, compliance costs, and fuel prices, and using official fuel burns from EIA, a more relevant picture emerges.

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[125] SED at p. 110.

[126] Wholesale price in 2006 was 4.7 c/kWh from 2006 Annual Report – Market Issues and Performance at 1. http://www.caiso.com/1bb7/1bb776216f9b0.pdf

Comparison of Compliance Cost to Net Revenues[127]

Facility	Net Annual Revenue	Annual Cost of Compliance	Cost as % of Net Revenue
Nuclear Plants	$4,303,028,414	$442,700,000	10%
Combined Cycle Plants	$236,414,062	$20,700,000	9%
Fossil Steam Plants	$175,423,833	$146,300,000	83%

Thus, the cost of compliance amounts to 83% of revenues after fuel costs for almost 9 out of 10 OTC units. The 17% net revenue remaining does not leave enough money to cover operations and maintenance expense, much less leaving anything available for continued investment or recovery of depreciation or profit. In short, when 9 out of 10 units cannot cover their operating expense based on the installation cost of a mitigating technology, that technology cannot be considered available under the CWA.

Finally, the statement that a facility owner should look to eliminate OTC through repowering needs comment. Repowering means tearing down the old steam boiler facility and replacing it with a new facility. That is not a technology available to minimize adverse environmental impact from an existing facility, it is an economic decision to build a new facility. Taking a law that governs cooling water intakes for existing facilities and forcing the owners to comply by tearing down that facility and building a new one can only be described as Orwellian. It certainly will not attract investment to California, nor has been shown, will it improve the aquatic environment or lower air emissions. It will increase costs and threaten reliability.

Section VII: Biologist Report

In order to prepare a full assessment of the Draft Policy's impact to its Mandalay and Ormond facilities, both in terms of cost and benefits, RRI commissioned an expert

[127] See Section X. Appendix/Supporting Documents, Item D.1.

review (by Mr. Thomas McCormick of Proteus, Inc) of the biological data obtained under the EPA Phase II monitoring requirements in 2006-2007, along with current plant operations and the existing environmental conditions of both facilities' intake source waters (Proteus Study).

Previous and current studies for both Ormond and Mandalay show that while a variety of species are impinged and entrained at the two facilities, the largest quantity are limited to a very few marine species. At Mandalay, Drums and Croakers comprise 74.6% of all species impacted. At Ormond, three groups of fishes, Specked Sanddab (41%), Queenfish (29%), and Drums and Croakers (17%) comprise 87% of all species impacted. These data reveal that these two generating facilities have very little impact on the sport and commercial fisheries of the California coast. Furthermore, the Proteus Study found that no endangered species were impacted at either facility.

Mr. McCormick prepared a distribution of the species impinged and entrained at each facility that formed the basis for monetizing their value in RRI's cost/benefit analysis prepared by NERA and included in Section VIII of these comments. Based on the IM/E studies which determined the actual flow annual eggs entrained for 2006-6007, Mr. McCormick estimated the adult fish needed to replace the entrained eggs at Ormond and Mandalay.[128] RRI used the "adults needed to replace" estimates to form the basis of its determination that the $200 million dollar cost for installing cooling towers at both facilities results in an effective cost of $3,000 per saved fish.

In addition to providing input into the cost/benefit analysis, the Proteus Study also assessed the impact of these plants on the ecological health of their intake source waters. Based on Mr. McCormick's expertise and knowledge of the California Bight, he

[128] Tables 5.2- 5.6 of the Proteus Study

concluded that neither facility has a significant adverse environmental impact to the fish populations therein. Mr. McCormick concluded that the El Nino-like water circulation pattern in the northern Pacific that causes sea water temperature shifts has a significant impact on the species that live in the California Bight. Another source of stress on the health of the aquatic environment is municipal waste and other industrial discharge. These and other items are discussed in more detail in Mr. McCormick's report, which is included in its entirety below.

RRI Energy, Inc.
Mandalay and Ormond Beach Generating Stations

Biology of fish species entrained at two Ventura County Generating Stations

September 2009

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Executive summary

The California State Water Board is developing a Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling. The policy addresses the issue of what impact, if any, the use of fresh and seawater for once-through cooling of power plants has on aquatic organisms through impingement, or entrainment.

To address U.S. Environmental Protection Agency (USEPA) Phase II regulations under §316(b) of the Clean Water Act (CWA) for cooling water intake structures (CWIS) that apply to existing facilities, Impingement Mortality and/or Entrainment Characterization Studies (IMECS) were conducted at Mandalay and Ormond Beach Generating Stations quantifying both impingement and entrainment in 2006 - 2007. Data from the IMECS is presented here to characterize temporal variations in abundance and variety of entrained eggs and larvae of fishes and invertebrates.

Data from the IMECS studies was used with published information on the life biology of the fish and invertebrates entrained to quantify possible impacts upon waters off southern California as per 316(b) guidelines. Life biology information on 37 of the most common species entrained was gathered to determine reproductive effort for a number of species where natural survival could be determined. Comparisons with adult fecundity suggest that the number of eggs and larvae entrained annually at the power plants represent the life-time reproduction of a small number of female fishes. The IMECS studies reveal that most of the fish and invertebrates entrainment come from only a few species and taxa (related groups).

Entrainment impacts on local fish and invertebrate populations must be placed within the context of oceanographic and climate conditions that influence waters of the southern California Bight and the fish populations therein. Periodic fluctuations in seawater temperatures result from shifts in water circulation in the northern Pacific. This Pacific Decadal Oscillation (PDO) is an El Niño like pattern that may persist for decades resulting in periods of warmer or cooler sea temperatures. These shifts in temperature affect the entire southern California Bight and have widespread impacts on the numbers and types of fish, invertebrate, and plants that live there. The size of many fish populations off southern California have undergone dramatic reductions over the past two decades as a result in a regional climate shift. Brooks et. Al. (2002) looked at non-exploited species of fish that represented different trophic levels, reproductive strategies, geographic ranges and connections to benthic or pelagic food webs. The study found regional declines throughout the bight point to a regional decline in productivity associated with a shift to an alternate climate regime. Ichthyoplnkton surveys y the California (CalcOFI) in 2005 found that larval fish were only half as abundant as they were in 2005.

It is not clear that once-through cooling by coastal generating stations creates an Adverse Environmental Impact (AEI) on the biological value of the southern

California Bight. The USEPA standard for the potential for damage from intake structures requires determining the potential damage to: principal spawning or breeding grounds, migratory pathways, nursery or feeding areas, or other functions critical during the life history. Neither Mandalay nor Ormond Beach intake structures demonstrably decrease the environmental value of adjacent waters as specified under the USEPA standard. The USEPA has directed that assessment of AEI should be based not on individual organisms, but on an evaluation of population level effects. Concerns should focus on "effects that may interfere with maintenance or establishment of optimum yields to sport or commercial fisheries, decrease populations of endangered organisms, and seriously disrupt sensitive ecosystems". Although the USEPA has stated that adverse aquatic environmental impacts occur whenever there will be entrainment or impingement damage as a result of the operation of a specific cooling water intake structure. The critical question is the magnitude of any adverse impact (Tenera, 2008). The exact point at which adverse aquatic impact occurs at any given plant site or water body segment is highly speculative and can only be estimated on a case-by-case basis."

Long-term monitoring of ichthyoplankton adjacent to other coastal power plants in California has not demonstrated that entrainment has a detectable negative impact on adjacent fish or invertebrate populations. (EPRI 2008). This has been the case for facilities that draw cooling water from enclosed bays and lagoons and for those located on the open coast. Like Mandalay and Ormond Beach other IMECS studies at coastal generating stations in southern California (Tenera 2007, 2008) indicated that 95% of entrainment losses were of commonly occurring forage species not utilized by commercial or sport fisheries. Populations of these species adjacent to power plants were determined to be similar to those found in distant habitats not influenced by the facilities. Life history and behavior of the most commonly entrained species likely reduces impacts from once through cooling on local populations. Other factors may have a greater influence on the abundance of these populations and there are numerous examples of how temperature, larval density, and habitat availability work to limit fish abundance. Changes in fish species and abundance reflect shifts in ocean circulation patterns and temperatures. These variables must be considered when examining fish populations within the SCB to avoid confusing natural changes with anthropogenic effects. Analysis by researchers at USEPA (Newbold and Iovanna 2007) suggests that if density constrains one or more stages of the life cycle, the loss of larvae to entrainment will have small effects at the population level.

Not all of the fishes and shellfishes in the source water are subject to entrainment or impingement, as was observed at Mandalay and Ormond Beach, the majority of entrainment and impingement is made up of only a few species. Differences in the vulnerability to entrainment and impingement occur due to different life histories of the species, as well as differences in habitat preferences and behavior. The potential magnitude of the losses due to entrainment and impingement depend on many factors. Examining distribution, habitats, and fecundity can help determine which species are at greatest risk. Larvae of species that are transported from far offshore into shallow coastal waters are not likely to contribute to an adult population.

Entrainment at Mandalay should be considered in light of the significant reduction in ichthyoplankton that takes place prior to cooling waters entering the facility. Densities of eggs and larvae drop steeply between the mouth of the Channel Islands Harbor (source water) and the entrance to the Edison Canal and again prior to entering the Cooling Water Intake Structure (CWIS). This reduction averaged 93% from June through November 2006. This reduction is probably attributable to filter feeding mollusks and arthropods that inhabit the Channel Islands Harbor and Edison Canal. Entrainment numbers may be low enough to meet 316(b) regulations, depending upon the definition of source waters for Mandalay.

Benefits resulting from the operation of the generating station should be considered when assessing local environmental impacts. The Mandalay generating station provides water circulation for an artificial canal and harbor complex, providing benefits for the overall health and productivity of these waters. Should this station change to closed-cycle cooling , the flow of waters within the Edison Canal and Channel Islands Harbor would diminish greatly. Low water exchange rates would result in lower oxygen levels and a decrease in both biomass and number of fishes and invertebrates, and birdlife. Without circulation of the seawater, levels of copper and other toxic compounds emanating from agricultural runoff and antifouling paint from hundreds of boats within the harbor would reach detrimental levels as they have in other marinas in California.

Ongoing monitoring of impingement at RRI Energy's Mandalay and Ormond Beach Generating Stations has documented low levels of impingement at these facilities. No threatened or endangered species were impinged or entrained at Mandalay or Ormond Beach Generating Stations.

Approximately 20 million people reside in Southern California, placing large demands upon the waters of the Southern California Bight (SCB). The bight receives municipal waste, street and river runoff, atmospheric fallout, harbor discharges, thermal discharges, and marine transportation. Municipal waste outfalls and non-point source runoff are the largest sources of pollution. Over a decade of monitoring coastal ecology, shoreline microbiology, water quality and benthic communities by the Southern California Coastal Water Research Project (SCCWRP) has shown that 89% of southern California sediments support healthy benthic communities, and another 9% were only marginally less healthy. Habitats around the Channel Islands were almost completely normal. Demersal (living on or near the bottom) fishes and invertebrates such as flatfishes and shrimp are an important part of the marine ecosystem, as well as targets for commercial and recreational fisheries. Surveys of the SCB in 2003 indicated that the great majority of demersal fish and invertebrate populations and assemblages were healthy. Biointegrity indices identified 96% of the shelf as "reference" (i.e., in normal condition) for fish, 84% for invertebrates, and 92% for fish and invertebrates combined. These numbers represent an improvement in fish health since the prior surveys in 1994.

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1. Background

1.1 Clean Water Act, Section 316(b)

Section 316(b) of the Clean Water Act (CWA) grants the Environmental Protection Agency (EPA) authority to regulate facilities with cooling water intake structures (CWIS) to assure that they reflect the best technology available (BTA) in order to minimize adverse environmental impacts. These impacts may arise from the impingement (IM) of aquatic organisms (i.e., fish, shellfish, and other forms of aquatic life) on intake structures and the entrainment (E) of eggs and larvae through cooling water systems. Since 1977, determination of BTA for cooling water intake structures has been directed by EPA draft guidance. In California, the state the California State Water Resources Control Board, implements Section 316(b) through National Pollution Discharge Elimination System (NPDES) permits issued by Regional Water Boards.

On July 9, 2004, the U.S. Environmental Protection Agency published the second phase of new regulations under §316(b) of the Clean Water Act (CWA) for cooling water intake structures (CWIS) that apply to existing facilities (Phase II facilities).

The Phase II Final Rule went into effect in September 2004, and applies to existing generating stations with CWIS that withdraw at least 50 million gallons per day (mgd) from rivers, streams, lakes, reservoirs, oceans, estuaries, or other waters of the United States. The regulations required all large existing power plants to reduce impingement mortality by 80-95% and to reduce the number of smaller aquatic organisms drawn through the cooling system by 60–90% when compared against a "calculation baseline". The water body type on which the facility is located, the capacity utilization rate, and the magnitude of the design intake flow relative to the waterbody flow determine whether a facility will be required to meet the performance standards for only impingement or both impingement and entrainment (IM&E). The final rule allowed these performance standards to be met through using the existing intake design, additional intake technologies, operational modifications, and restoration measures.

Litigation brought against EPA's Phase II Rule (Riverkeeper, Inc. v. EPA, No 04-6692) resulted in the Second U.S. Circuit Court of Appeals remanding many of the provisions of 316(b) (2nd Cir. Jan. 25, 2007). As a result, the EPA suspended the Cooling Water Intake Structure Regulations for existing large power plants (Federal Register: July 9, 2007, V. 72, No. 130, pg. 37107-37109) pending further rulemaking.

The California State Water Board has issued a notice of public hearing on September 16, 2009 to receive comments on its proposed Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling. The State Water Board states that with the suspension of the 316(b) Phase II Rule by the Federal government there currently are no federal or state standards for implementing section 316(b) for existing power plants. Permit writers must use their best professional judgment when re-issuing NPDES permits. Due to the resources required to evaluate the complex technical and biological issues related to intake structures, this approach puts a significant permitting burden on the Regional Water Boards and provides the potential for inconsistency in regulation of power plants that contribute to the statewide power grid. The State Water Board's position is that a new California policy would provide clear standards and consistency in implementation of section 316(b) in the State's NPDES permit program, and ultimately make better use of both stakeholder and Water Board resources.

1.2 Entrainment

The use of fresh and seawater for once-through cooling of power plants may have an impact on aquatic organisms through impingement, that is capture on some type of screening devise, or entrainment. Impinged animals are those retained by screens (mesh size usually 1 – 2 cm) as water is drawn into the power plant. Entrained animals pass through the screens and travel through the cooling water system before being discharged back to the receiving water body. Once drawn into the cooling system, entrained organisms are subjected to pressure changes, turbulence, temperature changes as much as 10°C, and possibly chlorination. Entrainment of or aquatic organisms into the CWIS removes billions of aquatic organisms from marine and freshwaters of the U.S. each year. Entrainment results in mortality for most of these early life stages, however, the effect on local populations is difficult to quantify given that mortality of early life stages (eggs and larvae) in wild populations is quite high and variable. Recent Impingement Mortality and/or Entrainment Characterization Studies (IMECS) at Reliant Energy's Mandalay and Ormond Beach Generating Stations quantified both impingement and entrainment. This report comments on entrainment and its possible impacts upon waters off southern California in light of 316(b) guidelines.

The one-year IMECS studies were conducted between February 2006 and February 2007 as specified in the Proposal for Information Collection (PIC) to meet requirements of the EPA 316(b) Phase II rule. Methods used were as follows:

- Impingement and entrainment sampling was conducted biweekly. Each sampling event consisted of four six-hour sampling periods during which separate samples were taken.
- Impinged fish and invertebrates were identified and enumerated as were entrained fish and invertebrate eggs and larvae.
- A calculation baseline was developed based upon the average density (#/m^3) of organisms in the source water or entrainment flow.

2. Description of the Mandalay and Ormond Beach Generating Stations

2.1 Mandalay Generating Station

Mandalay Generating Station is located on the coast of Ventura County, California, four miles west of the city of Oxnard. Cooling water is drawn from the Pacific Ocean via the Channel Islands Harbor and Edison Canal, a distance of 3.8 miles from the harbor mouth. The station consists of three units with a combined generating capacity of 577 megawatts. The two larger units use once through cooling while the smallest is a combustion turbine with no cooling water requirements. The two units share a single cooling water intake structure (CWIS).

2.1.1 Local Marine Environment

The Mandalay Generating Station draws seawater through the Edison Canal, which arises at the head of the Channel Islands Harbor. Both structures are man-made. The mouth of the Channel Islands Harbor opens into the Southern California Bight. The Bight is a transition zone for waters from two major zoogeographic provinces: Oregonian to the north and the San Diegan to the south. Cold waters carried southward by the California Current mix with warmer waters from the south resulting in highly productive waters within the Bight. The boundary between the two provinces changes depending upon the strength of the California Current, which, in turn, is influenced by the Pacific Decadal Oscillation (PDO). Boundary changes have a direct impact on fish populations. A description of the cooling water intake structure (CWIS) for the Mandalay Generating Station can be found in the Impingement Mortality and Entrainment Characterization Study performed by ENSR/AECOM.

2.2 Ormond Beach Generating Station

The Ormond Beach Generating Station is located on the southern edge of the City of Oxnard on Ormond Beach. The site is three miles west of Mugu Lagoon and two and a half miles from the entrance of Port Hueneme. Two 750 megawatt generating units have separate, but cojoined cooling water intake structures. Cooling seawater is drawn into the station via a 14 foot diameter pipe that terminates in a vertical intake 1,950 feet offshore in 35 feet of water. A sand-silt bottom surrounds the intake structure.

2.2.1 Local Marine Environment

Like Mandalay, Ormond Beach is situated within the southern California Bight and the biota contained within entrained waters changes daily, seasonally and on multi-decade time scales. The Ormond Beach CWIS draws water directly from ocean and the species mix is distinctly different than that of Mandalay. A full description of the (CWIS) for the Ormond Beach Generating Station can be found in the Impingement

Mortality and Entrainment Characterization Study performed by ENSR/ AECOM.

3 Entrainment Characterization Studies

3.1 Background

A Impingement Mortality and Entrainment Characterization Study (IMECS) was carried out in 2006 and 2007 for the Mandalay and Ormond Beach Generating Stations (MGS and OBGS) as part of the Comprehensive Demonstration Study (CDS) required by the Phase II Rule under 316(b) of the Clean Water Act (USEPA 1977, 2004). Data was gathered to provide an estimate of the current impingement and entrainment rates at the stations'. This information was intended to help evaluate the potential impacts of the circulating seawater intake system on fish and shellfish and calculate baseline levels of entrainment used to measure compliance with performance standards. The studies provided information on local species composition and the abundance of entrainable target species in cooling water sources.

3.2 Results of IMECS Studies at Mandalay and Ormond Beach: Fish assemblage overview.

3.2.1 Types of egg and larvae entrained

Results from the 2006 – 2007 surveys of for entrainment of eggs and larvae of fish and shellfish at Mandalay and Ormond Beach revealed that the vast majority off eggs and larvae entrained were from a relatively few groups of fishes. Only seven species, and taxa (related groups of fishes or invertebrates) made up 90% to 98% of the eggs and larvae entrained. Annualized entrainment for eggs and larvae are provided in Table 3.1. "Drums and Croakers" were the most abundant eggs in the entrainment samples. Flatfishes, that is, flounders and Speckled Sanddabs made up the next largest group. At Ormond Beach Speckled Sandabs were most abundant followed by Queenfish, Drums and Croakers and Northern Anchovy.

Table 3.1. Summary of annualized egg and larvae entrainment for actual flow at Mandalay and Ormond Beach generating stations based on samples taken from February 2006 to 2007. Data from IMECS study.

Mandalay		Ormond Beach	
Eggs		Eggs	
Drums & Croakers	74.6%	Speckled Sanddab	43.3%
Flounders	9.6%	Queenfish	24.6%
Speckled Sanddab	4.4%	Drums & Croakers	16.4%
Kelpbass	3.4%	White Croaker	3.7%
Unidentified eggs	3.1%	Northern Anchovy	3.0%
Righteye flounder	1.8%		
California Halibut	1.2%		
% of Eggs	98%	% of Eggs	90%

Mandalay		Ormond Beach	
Larvae		Larvae	
Shrimp	31%	Shrimp	93.6%
Arrow goby	21.7%	Northern Anchovy	1.7%
Cheekspot goby	18.1%	Crab Megalopa	1.3%
Bay Blenny	10.3%	White Croaker	0.7%
Yellowfin goby	7.0%	% of larvae	98%
Topsmelt	4.3%		
Blackeye goby	1.8%		
% of larvae	94.2%		

A listing of all species entrained at Mandalay during the IMECS study is shown below in Table 3.2. The table illustrates how a few species account for most the entrainment.

Table 3.2
Summary of Annual Entrainment for Actual Flow and Design Flow at the Mandalay Generating Station Cooling Water Intake Structure. Data from 2006 -2007 IMECS study.

Species	Actual Flow Annual Entrainment	% Composition	Design Flow Annual Entrainment	% Composition
Eggs				
Drums and croakers	3,877,557	74.6%	10,538,391	78.3%
Flounder	497,521	9.6	1,045,307	7.8
Speckled sanddab	230,434	4.4	694,066	5.2
Kelp Bass	177,702	3.4	337,834	2.5
unidentified eggs	161,168	3.1	287,545	2.1
Righteye flounder	91,545	1.8	148,639	1.1
California halibut	60,044	1.2	114,151	0.8
Topsmelt	48,178	0.9	114,543	0.9
Spotted turbot	23,562	0.5	46,478	0.3
Petrale sole	19,484	0.4	43,640	0.3
Queenfish	9,677	0.2	85,333	0.6
Total Eggs	**5,196,871**		**13,455,585**	
Larvae				
shrimp larvae	15,233,864	31.0%	72,242,282	33.6%
Arrow goby	10,673,613	21.7	28,464,010	13.2
Cheekspot goby	8,890,197	18.1	38,609,088	18.0
Bay blenny	5,058,643	10.3	11,932,106	5.6
Yellowfin goby	3,436,603	7.0	44,848,715	20.9
Topsmelt	2,099,575	4.3	5,980,345	2.8
Blackeye goby	888,195	1.8	1,765,790	0.8
California clingfish	619,326	1.3	1,879,150	0.9
Caridean Shrimp	509,367	1.0	869,498	0.4
Longjaw mudsucker	399,967	0.8	1,764,103	0.8
Kelpfish	347,794	0.7	874,122	0.4
Jacksmelt	321,224	0.7	1,321,120	0.6
Shadow goby	315,146	0.6	3,074,311	1.4
Coralline sculpin	50,967	0.1	131,706	0.1
Northern Anchovy	44,974	0.1	95,021	<0.1
larvae	44,653	0.1	92,102	<0.1
California grunion	38,811	0.1	131,706	< 0.1
Bay pipefish	38,017	0.1	127,740	<0.1
Righteye flounder	33,936	0.1	48,303	<0.1
Northern lampfish 2	3,400	< 0.1	40,629	<0.1
Bay goby	19,775	< 0.1	101,783	<0.1
Pacific herring	13,458	<0.1	81,543	<0.1
Blind goby	11,235	<0.1	39,876	<0.1
Pacific staghorn sculpin	10,520	<0.1	66,845	<0.1
Blennies	9,983	<0.1	48,378	<0.1
Painted greenling	9,169	<0.1	67,620	<0.1
Giant kelpfish	8,136	<0.1	66,554	<0.1
Island keplfish	7,570	<0.1	20,408	<0.1
Pacific sanddab	3,836	<0.1	33,825	<0.1
Snailfishes and lumpsuckers	2,099	<0.1	17,172	<0.1
Spotted turbot	1,494	<0.1	18,056	<0.1
crab larvae	396	<0.1	16,428	<0.1
Total Larvae	**49,165,944**		**214,891,545**	

Table 3.2 continued.

Species	Actual Flow Annual Entrainment	% Composition	Design Flow Annual Entrainment	% Composition
Juveniles				
Longjaw mudsucker	16,169	51.3%	42,275	28.1%
Arrow goby	15,375	48.7%	108,405	71.9
Total Juveniles	**31,544**		**150,679**	
Total	**54,394,358**		**228,497,808**	

Details of entrained species at the Ormond Beach Generating Station, showing how only several species account for most entrainment are shown in Table 3.3.

Table 3.3. Summary of Annual Entrainment for Actual Flow and Design Flow at the Ormond Beach Generating Station Cooling. Data from 2006 -2007 IMECS study.

Species	Actual Flow Annual Entrainment	Percent	Design Flow Annual Entrainment	Percent
Eggs				
Speckled sanddab	263,458,961	41.2%	1,275,207,335	39.4%
Queenfish	181,872,653	28.5%	829,754,955	25.6%
Drums and croakers	110,315,049	17.3%	596,799,633	18.4%
White croaker	6,712,062	1.1%	117,592,644	3.6%
Northern Anchovy	19,584,283	3.1%	98,964,976	3.1%
Paralichthidae/Pleuronectidae	11,676,896	1.8%	85,585,694	2.6%
California tonguefish	15,850,159	2.5%	54,668,934	1.7%
Soles and turbots	7,277,890	1.1%	35,777,558	1.1%
Righteye flounder	4,938,972	0.8%	31,615,067	1.0%
unidentified eggs	2,568,009	0.4%	30,367,032	0.9%
Spotted turbot	2,544,985	0.4%	19,954,707	0.6%
English sole	4,363,923	0.7%	18,786,253	0.6%
kelp bass	2,033,260	0.3%	10,722,685	0.3%
Pacific hake	1,861,560	0.3%	8,767,147	0.3%
Chub mackerel	1,432,650	0.2%	8,593,869	0.3%
Hornyhead turbot	784,058	0.1%	4,913,485	0.2%
20-25 no oil	693,661	0.1%	3,480,575	0.1%
Smalleye squaretail	294,670	<0.1%	1,508,265	<0.1%
Round herring	274,113	<0.1%	1,403,042	<0.1%
Pacific herring	34,908	<0.1%	562,480	<0.1%
Labrid	10,658	<0.1%	264,848	<0.1%
Cusk eel	81,071	<0.1%	274,766	<0.1%
Senorita	24,975	<0.1%	127,835	<0.1%
Mackerels	460	<0.1%	119,700	<0.1%
C-O sole	19,094	<0.1%	97,733	<0.1%
Bigmouth Flounder	10,568	<0.1%	54,095	<0.1%
Popeye blacksmelt	5,037	<0.1%	41,746	<0.1%
Total Eggs	**638,724,587**		**3,236,007,059**	
shrimp larvae	74,555,005	90.5%	702,861,560	93.0%
Northern Anchovy	3,424,889	4.2%	14,153,517	1.9%

crab megalopa	1,447,258	1.8%	11,809,905	1.6%
White croaker	325,972	0.4%	4,837,491	0.6%
Northern lampfish	422,520	0.5%	2,426,758	0.3%
Bay blenny	368,723	0.4%	1,717,334	0.2%
California smoothtongue	29,251	<0.1%	1,514,057	0.2%
Diamond turbot	38,981	<0.1%	1,368,826	0.2%
Queenfish	313,393	0.4%	1,153,662	0.2%
Speckled sanddab	140,887	0.2%	1,117,762	0.1%
California halibut	220,669	0.3%	1,024,039	0.1%
Spotfin Croaker	113,370	0.1%	819,562	0.1%
English sole	86,721	0.1%	808,636	0.1%
Arrow goby	59,575	0.1%	883,170	0.1%
Pacific hake	59,260	0.1%	744,362	0.1%
Cheekspot goby	26,474	<0.1%	742,468	0.1%
Rockfish	64,658	0.1%	661,695	0.1%
Pacific staghorn sculpin	8,372	<0.1%	731,491	0.1%
Chub mackerel	37,742	<0.1%	739,430	0.1%
California clingfish	65,482	0.1%	542,698	0.1%
unidentified larvae	69,739	0.1%	559,657	0.1%
Coralline sculpin	63,454	0.1%	490,391	0.1%
Yellowfin goby	9,422	<0.1%	454,196	0.1%
Jacksmelt	7,804	0.0%	341,377	<0.1%
Senorita	54,363	0.1%	278,257	<0.1%
Kelpfish	11,589	<0.1%	321,840	<0.1%
Bay pipefish	74,786	0.1%	251,985	<0.1%
Shadow goby	38,918	<0.1%	249,710	<0.1%
Goby	41,357	0.1%	205,064	<0.1%
Bay goby	7,963	<0.1%	173,837	<0.1%
Painted greenling	514	<0.1%	199,547	<0.1%
Popeye blacksmelt	622	<0.1%	161,946	<0.1%
Lancelet	492	<0.1%	167,099	<0.1%
Longjaw mudsucker	728	<0.1%	172,857	<0.1%
Blind goby	8,438	<0.1%	95,028	<0.1%
Spotted turbot	2,314	<0.1%	87,382	<0.1%
Fantail sole	17,051	<0.1%	87,277	<0.1%
Smalleye squaretail	8,905	<0.1%	100,949	<0.1%
Blackeye goby	34,444	<0.1%	66,157	<0.1%
Cleaner Shrimp/Hippolytidae	8,332	<0.1%	44,844	<0.1%
Island Kelpfish	13,004	<0.1%	44,307	<0.1%
Pygmy poacher	6,998	<0.1%	64,440	<0.1%
Scalyhead sculpin	217	<0.1%	56,417	<0.1%
Giant kelpfish	2,354	<0.1%	36,364	<0.1%
Pacific sand lance	4,998	<0.1%	46,034	<0.1%
kelp bass	9,518	<0.1%	48,717	<0.1%
Corbina	7,489	<0.1%	25,816	<0.1%
Pacific Barracuda	12,846	<0.1%	44,608	<0.1%
Engraulidae	2,239	<0.1%	34,593	<0.1%
California tonguefish	8,526	<0.1%	43,638	<0.1%
Sargo	8,379	<0.1%	42,886	<0.1%
Pacific sardine	8,325	<0.1%	42,612	<0.1%
Snailfishes and lumpsuckers	8,325	<0.1%	42,612	<0.1%
Yellowfin croaker	6,428	<0.1%	22,159	<0.1%
Total Larvae	**82,370,079**		**755,763,021**	
Crab juveniles	191,550	60.8%	1,234,605	59.5%

Crangonidae	20,151	6.4%	311,335	15.0%
Market squid	103,114	32.8%	527,788	25.5%
Total Juveniles	**314,815**		**2,073,727**	
Total	**721,409,481**		**3,993,843,807**	

A more detailed look at the species entrained at both stations is provided in Table 3.4. Within the family Sciaenidae, shown as Drums and Croakers in Table 1., there are seven species found in the southern California Bight. Collectively these fish accounted for 74.6% of fish eggs entrained at Mandalay and 44% of fish eggs at Ormond Beach. Shrimp account for the largest percentage of entrained larvae with 31% at Mandalay and 94% at Ormond Beach. At Mandalay four different species of gobi comprised the next most abundant group, accounting for 48.6% of entrained larvae. Larvae of the family gobiidae share common traits, making differentiation difficult. This particularly true for early larvae of the arrow goby (*Clevlandia ios*), cheekspot goby, (*Ilypnus gilberti*) and shadow goby (*Quientula y-cauda*). For identification purposes larvae of these species are often combined into the *Clevlandia, Ilypnus, Quientula, or* 'CIQ goby complex".

Table 3.4. Listing of fish species that occur in southern California from which eggs or larvae may be entrained at Mandalay and Ormond Beach. This table shows all of the species found in southern California that may come under one of the descriptions of entrained eggs or larvae. For example, there are 23 local species that may be identified as "Flatfishes". Only eight species of fish, highlighted in **bold,** were fond in significant numbers in the IMECS studies.

<u>Drums and Croakers</u>	
Queenfish	*Seriphus politus*
White Seabass	*Atractoscion nobilis*
Shortfin Corvina	*Cynoscion parviminnis*
Yellowfin Croaker	*Umbrina roncador*
California Corbina	*Menticirrhus undulatus*
White Croaker	*Genyonemus lineatus*
Spotfin Croaker	*Roncador stearnsii*
Black Croaker	*Cheilotrema saturum*

Flatfishes	
California tounguefish	*Syumphurus atricauda*
California halibut	*Paralichthys californicus*
Pacific halibut	*Hippoglossus stenolepis*
Rock sole	*Lepidopsetta bilineata*
Fantale sole	*Xystreurys liolepis*
Bigmouth sole	*Hippoglossina stomata*
Curlfin turbot	*Pleuronichthys decurrens*
Hornyhead turbot	*Pleuronichthys verticalis*
Spotted turbot	*Pleuronichthys ritteri*
C-O Turbot	*Pleuronichthys coenosus*
Sand sole	*Psettichthys menanostictus*
Diamond turbot	*Hypsopetta guttulata*
English sole	*Parophrus vetulus*
Butter sole	Isopsetta isolepis
Starry flounder	Platichthys stellatus
Longfin sanddab	Citharichthys xanthostigma
Pacific sanddab	Citharichthys sordidus
Speckled sanddab	Citharichthys stigmaeus
Rex Sole	Glyptocephalus zachirus
Deepsea sole	*Embassichthys bathybius*
Arrowtooth flounder	*Atheresthes stomais*
Dover sole	*Microstomus pacificus*
Petrale sole	*Eopsetta jordani*
Kelpbass	*Paralabrax clathratus*
Northern anchovy	*Engraulis mordax*

Gobies - Family Gobiidae		
Yellowfin goby	*Acanthogobius flavimanus*	From Japan
Cheekspot goby	*Ilypnus gilberti*	
Arrow goby	*Clevelandia ios*	

Combtooth Blennies - Family Blenniidae	
Bay Blenny	*Hypsoblennius gentilis*

Shrimp were the most abundant type of larvae in entrainment samples for both Mandalay (31%) and Ormond Beach (94%). Shrimp species found in southern California Bight are shown in Table 3.5.

Table 3.5. Listing of shrimp species that occur in southern California from which eggs or larvae may be entrained at Mandalay and Ormond Beach. This table shows all of the species that may be entrained as eggs.

Bay Shrimp	
California Bay shrimp	*Crangon franciscorum*
Blacktail bay shrimp	*Crangon nigricauda*
Blackspotted bay shrimp	*Crangon nigromaculata*
Oriental shrimp	*Palaemon macrodactylus*l
Prawns	
Golden prawn	*Penaeus californiensis*
Ridgeback prawn	*Sicyonia ingentis*
Spot prawn	*Pandalus platyceros*
Coonstriped Shrimp	*Pandalus danae*
Pink Shrimp, ocean shrimp	*Pandalus jordani*
Red Rock Shrimp	*Lysmata californica*
Blue Mud Shrimp	*Upogebia pugettensis*
Ghost Shrimp	*Callianassa californiensis*
	Callianassa affinis
	Callianassa gigas

3.2.2 Densities of eggs and larvae in entrainment waters.

Densities of eggs and larvae from fish and shellfish in intake waters (number per cubic meter of water, or #/m^3) vary both temporarily and spatially. The annual average densities (#/m^3) of entrained eggs, fish larvae and juveniles, shellfish larvae and juveniles differed between Mandalay and Ormond Beach during the 2006 – 2007 sampling period. At Mandalay, fish and shellfish larvae were the predominant groups, while at Ormond Beach fish eggs were dominant. See Table 3.6.

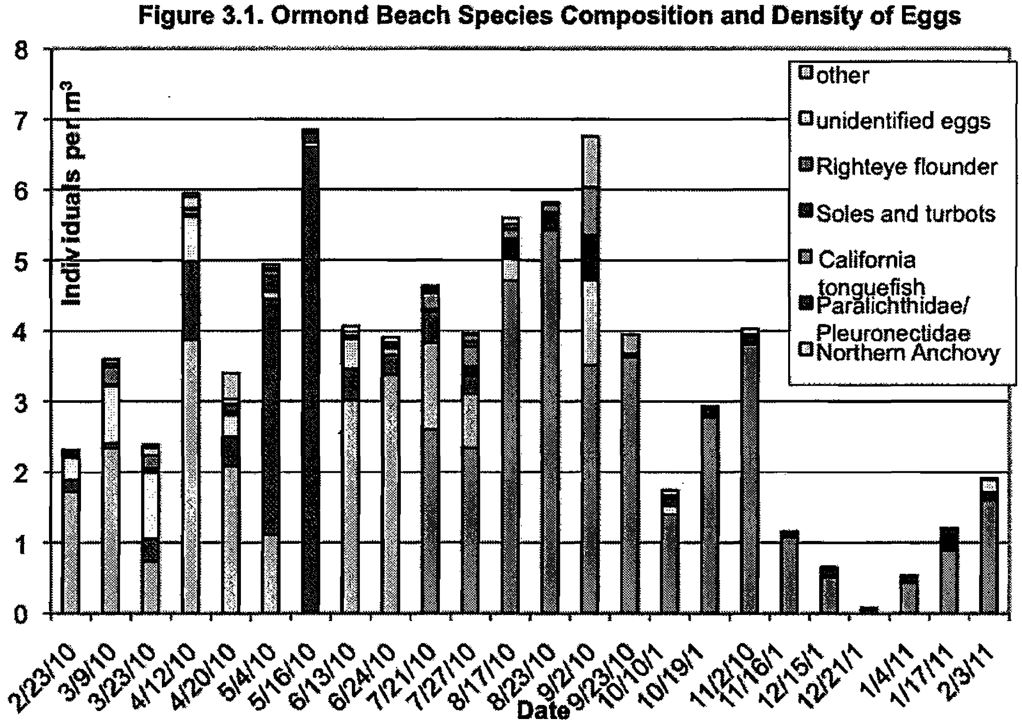
Table 3.6. Annual average number of entrained fish eggs and larvae, and shellfish eggs and larvae entrained at Mandalay and Ormond Beach generating stations during the 2006 – 2007 sampling period.

	Mandalay		Ormond Beach	
	$\#/m^3$	%	$\#/m^3$	%
Eggs	0.33	5.4	3.4	79.0
Larvae (fish)	0.40	64.0	0.045	1.04
Juveniles (fish)	0.00042	0.07		
Larvae (shell)	0.19	31.0	0.84	19.0
Juveniles (shell)	0	0	0.00021	0.05

3.2.3 Seasonality in eggs and larvae occurrence in entrainment waters.

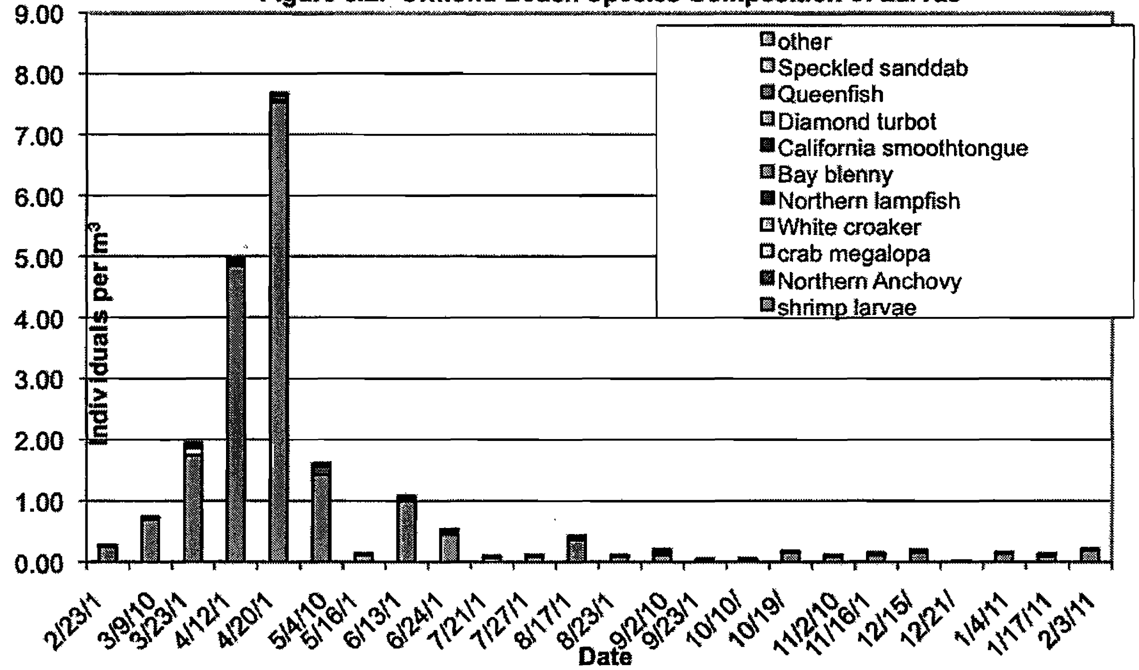
Reproduction for most animals is usually tied to seasonal changes. In the marine environment, timing of reproduction and the duration of the egg and planktonic stages will affect the number of eggs and larvae in the water column at any particular time. Figure 3.1 summarizes temporal variation in fish egg composition and density at Ormond Beach. While average egg densities are approximately $3.5/m^3$ throughout the year, they are higher in the spring and early summer and lowest in the fall and winter. Species composition varies seasonally.

Figure 3.1. Ormond Beach Species Composition and Density of Eggs



Seasonal occurrence of larvae from each species is more extreme that the number of eggs. Figure 3.2. shows that at Ormond Beach, shrimp larvae predominate and are most abundant in winter and spring.

Figure 3.2. Ormond Beach Species Composition of Larvae



Reduction of ichthyoplankton densities at Mandalay.

The harbor environment from which Mandalay draws water containing biota that different from those found in coastal waters used as a source of cooling water for Ormond Beach. Assessments of ichthyoplankton densities at the mouth of the Channel Islands Harbor, the entrance to the Edison Canal from the harbor, and within the Edison Canal upstream of the Mandalay CWIS revealed a dramatic decline in egg and larvae density at each transition. Tables 3.7 and 3.8 show the extent of these declines.

Table 3.7. Densities of ichthyoplankton larvae (#/m^2) observed during IMECS sampling station between June and November 2006 for Mandalay Generating Station. (Source IMECS study, ENSR).

	Mandalay	Edison Canal	Channel Islands Harbor
June 2006	0.10	0.39	2.4
July 2006	0.12	0.5	0.39
August 2006	0.12	1.29	2.41

September 2006	0.3	1.03	2.89
October 2006	0.17	1.27	0.98
November 2006	0.35	0.51	1.06

Table 3.8 Differences in ichthyoplankton densities at the mouth of the Channel Islands Harbor, the entrance to the Edison Canal, and within the Edison Canal upstream of the Mandalay CWIS

	(CH – MG) / CH
June 2006	96%
July 2006	68%
August 2006	95%
September 2006	90%
October 2006	83%
November 2006	67%

MG = Within Edison Canal, upstream of Mandalay Generating Station
CH – Mouth of Channel Islands Harbor

These reductions in ichthyoplankton densities are largely represents the loss of plankton to the large biomass of filter feeders that inhabit the harbor and canal. These filter feeders include topsmelt, anchoveys, sardines, clams, oysters, mussels and barnacles, and marine worms. These reductions may have a bearing on Mandalay's 316(b) compliance depending upon the definition of source water.

3.3 Species information

To determine the impact that loss through entrainment may have on source populations of fish basic life-history information was gathered on species most likely to be entrained at Mandalay and Ormond Beach.. Where possible, the following information is was obtained:

- Age at maturity
- Length at maturity
- Spawning time of year
- Number of spawns per year
- Fecundity – number of eggs per spawn
- Survival ratio of eggs to larvae
- Life span of fish

Table 3.9, attached as an Excel spreadsheet, "Table of fish Biology: Biology of Fish Entrained as Eggs or Larvae", summarizes available life biology information for 37 species of fish.

Table 3.9 –Biology of Entrained Fish, see Appendix

The life biology information provides in the table will serve as a basis for understanding how loss of eggs and larvae through entrainment may have an impact on local fish populations. Additional biological information on some of the more common species is presented in Appendices A – E and represents a compilation of data from the literature and Tenera, Inc. For almost all species there is a lack of information on survival rates during the transitions from eggs to larvae to juvenile fish.

3.4 Calculations of mortality rates

Life history information on the most abundant entrained species at Mandalay and Ormond Beach was used in conjunction with known or estimated mortality rates to determine the loss of reproductive potential from adult fish. For OBGS this information is presented in the following Excel spreadsheet.

Ormond Beach

Table 3.10 OBGS Fish Growth and Survival.xls, see Appendix

Queenfish, "Drums and Croakers" and white croakers (all croakers of the family Sciaenidae) made up the largest number of eggs entrained. The Survival tab of the spreadsheet provides basic information on fish biology including size at hatch, growth rate / day, larval duration, and average settlement size. This information was gathered from the scientific literature. The table next summarizes the entrainment of eggs at Ormond Beach.

A difficulty encountered when estimating the number of fish resulting from entrained eggs and larvae is that the survival rate from hatch to metamorphosis (settlement out of the plankton) is not known for the majority of species. A review of the Instantaneous Natural Mortality (M) for a variety of marine fish species (McGurk, 1985) shows that mortality for larvae fish falls within the range of 0.005 – 1.0 per day. The median mortality (M = 0.5 /day) was used here to estimate the survival of eggs to metamorphosis. Calculations are shown in the "M Calculations" tab of the spreadsheet.

Egg Entrainment

The number of fish eggs that would survive the larval stage and metamorphose into small juveniles is shown. With M = 0.5 / day, the 181,872,653 queenfish eggs entrained for 2006 – 2007 would result in only 347 metamorphosed juvenile fish 3.8 mm in length. Subsequent Annual mortality of juvenile Queenfish has been measured at M = 0.42 / year.

Larval Entrainment
The number of entrained larvae are so low that with an Instantaneous Natural Mortality Rate of 0.5/ day, none (0) would survive to metamorphosis.

Natural mortality is highly variable from season to season and from one species to the next. Sources of variation arise from the condition of spawning stocks, differences in water temperature, and egg size. Coastal currents, eddies, and storms can influence the distribution of eggs and larvae, sometimes concentrating them or dispersing them. This patchiness has a significant impact upon larval survival since it alters the ability of predators to find and consume eggs and larvae.

Mandalay
The type and numbers of eggs and larvae entrained at Mandalay differed somewhat from those at Ormond Beach, reflecting differences in the source waters used for cooling. The Mandalay Goby Growth Spreadsheet, Table 3.11, provides biological information on "Drums and Croakers", Gobies, and, shrimp.

Table 3.11
File: Mandalay Goby, Fish, Shrimp.xls, see Appendix

Eggs
The most abundant eggs entrained were "Drums and Croakers" with 3,877,557 eggs entrained.

Larvae
Three species of gobies made up the largest amount of larvae entrained. The "Gobies" tab of the spreadsheet provides biological information about this group. Instantaneous Mortality Rates for gobies are known. One quarter of the entrained gobies are Yellowfin gobies, an introduced species. To put this in perspective, a four-year study of the fishes of San Diego Bay, estimated that gobi densities averaged 5 / m^2, or 10.6 million of these fish in the bay (Allen 1999).

Larvae – shrimp
Shrimp survival of 1% to settlement was used based on data on the Pink or Ocean Shrimp, *Pandalus jordani*. Shrimp accounted for the 15,233,864 entrained larvae, 152,339 of which would survive to settlement. The "Shrimp" tab shows an equivalent number of metamorphosed juvenile shrimp.

No threatened or endangered species were impinged or entrained at Mandalay or Ormond Beach Generating Stations.

4 Potential Entrainment Impact of Mandalay and Ormond Beach Generating Stations

4.1 Assessment Approach and fish reproductive biology

The 2006 – 2007 IMECS studies were performed at Mandalay and Ormond Beach Generating Stations to comply with the EPA Phase II 316(b) regulations for existing power plants. Phase II rules were suspended by the EPA in 2007 as the result of a court ruling. Prior to the publication of the Phase II regulations in 2004, regulators relied on EPA's (1977) draft guidelines for evaluating adverse impacts of cooling water intake structures to determine compliance with Section 316(b). Since the new Phase II regulations were based on performance standards for reducing entrainment and impingement and did not explicitly rely on determining whether existing levels represented an adverse environmental impact (AEI), EPA determined that the "*...performance standards reflect the best technology available for minimizing adverse environmental impacts determined on a national categorical basis.*" Although AEI was not intended to be used in assessing compliance under the new regulations, the potential for AEI was still considered in determining the types of plants and water bodies where the new performance standards would apply (Tenera).

In its 1977 draft guidance document, EPA stated that "*Adverse aquatic environmental impacts occur whenever there will be entrainment or impingement damage as a result of the operation of a specific cooling water intake structure. The critical question is the magnitude of any adverse impact.*" EPA further stated in the document that "*Regulatory agencies should clearly recognize that some level of intake damage can be acceptable if that damage represents a minimization of environmental impact.*"

The 2006-2007 IMECS studies were performed to determine if the existing intakes and operations results in AEI. Entrainment and impingement losses were measured by collecting samples in front of the cooling water system intake. This review gathered basic biological information on the entrained species to help put measured losses into context of the marine ecological setting at the facilities.

4.1.1 Cooling Water Intake Structure (CWIS) Impacts

Three types of effects are associated with intake structures and once-through cooling at power plants: thermal effects from the discharge plume, impingement effects, that is the capture of aquatic organisms on intake screens, and entrainment effects. Thermal effects are regulated under Section 316(a) of the Clean Water Act and the *Water Quality Control Plan for Control of Temperature in the Coastal and Interstate Waters and Enclosed Bays of California (California Thermal Plan).* Entrainment of fish and invertebrate eggs, larvae and early juvenile stages organisms too small to be retained by the screens subjects these stages to abrupt pressure and temperature changes and turbulence. It is assumed that all entrained organisms die as a result.

The Phase II 316(b) regulations required that IM&E studies include "*Documentation of current impingement mortality and entrainment of all life stages of fish, shellfish, and any protected species identified previously and an estimate of impingement mortality and entrainment to be used as the calculation baseline.*" The Rule's entrainment performance standard focuses on addressing impacts to fish and shellfish rather than lower tropic levels such as phyto- and zooplankton. EPA recognized the low vulnerability of phyto- and zooplankton in its 1977 draft 316(b) guidance (EPA 1977). There are several reasons why there is a low potential for impacts to phyto- and zooplankton and why the EPA decided to focus on potential effects on fish and shellfish (Tenera). The reasons include:

- The extremely short generation times of most holoplanktonic organisms; on the order of a few hours to a few days for phytoplankton and a few days to a few weeks for zooplankton

- Both phyto- and zooplankton have the capability to reproduce continually depending on environmental conditions

- The most abundant phyto- and zooplankton species along the California coast have populations that span the entire Pacific or in some cases all of the world's oceans. For example, *Acartia tonsa*, one of the common copepod species found in the nearshore areas of California is distributed along the Atlantic and Pacific coasts of North and South America and the Indian Ocean. Relative to the large abundances of phyto- and zooplankton, larval fishes make up a small fraction of the total numbers of organisms present in seawater.

The EPA has focused on potential impacts on fishes and shellfishes because they are more susceptible to entrainment effects for the following reasons:

- They have much shorter spawning seasons relative to phyto- and zooplankton. In many species, spawning occurs only once during the year

- Unlike phyto- and zooplankton that may be distributed over large oceanic areas, most fishes are restricted to the narrow shelf along the coast and in some cases have specific habitat requirements that further restrict their distribution

- Unlike many phyto- and zooplankton, there is a greater likelihood of mortality due to entrainment in larval fishes, since many lower tropic level organisms are not soft bodied as is the case for finfish and are better able to tolerate passage through the cooling system (Tenera).

Due to the 2007 suspension of the 316(b) Phase II rule, state and federal permit writers have been directed to implement Section 316(b) on a case-by-case basis using "best professional judgment". For most facilities, the permit applicant is obligated to provide the California Regional Water Quality Control Board with the "best information reasonably available" to assist it in fulfilling its decision making responsibility. To make Section 316(b) decisions, permit writers have relied on precedent from other cases and on USEPA's (1977) draft "Guidance for Evaluating the Adverse Impact of Cooling Water Intake Structures on the Aquatic Environment: Section 316(b) P.L. 92-500." As is clear from the statute, the permit writer must consider two basic issues in making a finding that an intake technology employs the BTA for minimizing AEI:

- Whether or not an AEI is caused by the intake and, if so,
- What intake structure represents BTA to minimize that impact.

The usual approach for a 316(b) demonstration would be to consider the question of BTA only if a determination has been made that a facility is causing an AEI (Tenera).

4.1.2 Adverse Environmental Impact Standard

No specific language defines Adverse Environmental Impacts, and permit decisions have been based on the United States Environmental Protection Agency's (USEPA) guidance documents. USEPA has directed that assessment of AEI should be based not on individual organisms, but on an evaluation of population level effects. Concerns should focus on "effects that may interfere with maintenance or establishment of optimum yields to sport or commercial fisheries, decrease populations of endangered organisms, and seriously disrupt sensitive ecosystems". Although the USEPA has stated that adverse aquatic environmental impacts occur whenever there will be entrainment or impingement damage as a result of the operation of a specific cooling water intake structure. The critical question is the magnitude of any adverse impact (Tenera). The exact point at which adverse aquatic impact occurs at any given plant site or water body segment is highly speculative and can only be estimated on a case-by-case basis."

USEPA guidelines to determine the extent of AEI include "relative biological value of the source water body zone of influence for selected species and determining the potential for damage by the intake structure" based on the following considerations of the value of a given area to a particular species:

- Principal spawning ground
- Migratory pathways
- Nursery or feeding areas
- Numbers of individuals present
- Other functions critical during the life history

Additional criteria suggested by Tenera include:

- Distribution (pelagic, near-shore, sub-tidal and intertidal)
- Range, density and dispersion of population
- Population center (source or sink)

- Magnitude of effects
- Long-term abundance trends (e.g. fishery catch data)
- Long-term environmental trends (climatology and oceanography)
- Life history strategies (e.g. longevity and fecundity

The value of these criteria for impinged or entrained species will help with the determination of the impact of their loss on the local environment.

Not all of the fishes and shellfishes in the source water are subject to entrainment or impingement, as was observed at Mandalay and Ormond Beach, the majority of entrainment and impingement is made up of only a few species. Differences in the vulnerability to entrainment and impingement occur due to different life histories of the species, as well as differences in habitat preferences and behavior. The potential magnitude of the losses due to entrainment and impingement depend on many factors. Examining distribution, habitats, and fecundity can help determine which species are at greatest risk. Larvae of species that are transported from far offshore into shallow coastal waters are not likely to contribute to an adult populations.

To better assess fish communities biologists have started to evaluate them on the basis of their habitat associations (Allen and Pondella 206). Habitat types for fish communities near Mandalay and Ormond Beach include:

- Bays, harbors, and estuaries
- Sub-tidal and intertidal rocky reefs and kelp beds
- Coastal pelagic
- Continental shelf and slope
- Deep pelagic including deep bank and rocky reef

The origin and habitat as well as fisheries for the most abundant fish species entrained at Mandalay and Ormond Beach are shown in Table 4.1.

Table 4.1
Habitat associations for entrained taxa at Mandalay and Ormond Beach Generating Stations. Primary habitat in bold, uppercase and secondary habitat in lower case. S – sport fishery, C – commercial fishery.

		Fishery	Habitats			
Scientific Name	Common Name	S-Sport C-Comm.	bays, Harbors	Reefs kelp beds	coastal pelagic	shelf
Drums & Croakers						
Genyonemus lineatus	white croaker	S, C	x	**X**		x
Seriphus politus	queenfish	S, C			**X**	x
Atractoscion nobilis	white seabass	S, C			**X**	x
Gobiidae unid. CIQ	goby complex		**X**			
Citharichthys stigmaeus,	speckled sanddab	S	x		**X**	
Paralichthys californicus	Califoernia halibut	S, C	x			**X**
Paralabrax spp.	sand and kelp basses	S	x	**X**		
Hypsoblennius spp.	combtooth blennies		**X**	x		

Engraulidae unid.	anchovies	C	x		X	
Sardinops sagax	Pacific sardine	C			X	
Pandalus, Crangon	Shrimp	C	x			X
Cancer spp.	cancer crabs	S, C	x	x		X

Species most commonly entrained at Mandalay and Ormond Beach originate in rocky reefs, kelp beds, coastal pelagic and shelf environments. Many of these species have larval stages that last for a month or more, providing sufficient time for distribution over a wide area of the southern California Bight. The most abundant eggs were from "Drums and Croakers" originating in shelf and coastal pelagic habitats The most abundant larvae (shrimp) were from bay and shelf habitats. These eggs may arise from as many as 15 shrimp species. Eggs and larvae of species found in habitats far from the generating station may be regularly entrained. In the cast of speckled sanddabs a larval duration of over 250 days can result in larvae that are distributed over a wide area for long periods of time. Mortality during this prolonged stage will be more significant than that associated with entrainment.

4.2 Fish populations in context – Oceanographic and fish population trends

In an environmental review of impingement and entrainment for Cabrillo Power, Tenera, Inc. produced the following review of recent oceanographic and fish population trends for southern California. Water temperatures and current patterns have a significant effect on marine faunal composition. Understanding the nature of the variability in these physical factors is essential for explaining long-term population trends for many marine species. The Southern California Bight is the transition zone between the cool temperate Oregonian fauna, from the north and the warm temperate San Diegan fauna from the south. This transition is caused by the geology and oceanic current structure of the region. The source of cold water is the California Current, the eastern branch of the North Pacific Gyre. The strength of the California Current varies on many time frames. On a multi-decadal scale it oscillates between a warm and cold phase referred to as the Pacific Decadal Oscillation (PDO). During the warm phase the PDO is relatively weaker than average, while during the cold phase it is stronger than average. This multi-decadal oscillation has had a significant effect of the Southern California Bight (SCB) and the most pertinent debate concerns when it will switch back to a cold phase (Bogard et al. 2000, Durazo et al. 2001, Lluch-Belda et al. 2001). During the cold phase, the bight is colder than average and dominated by the Oregonian fauna. The opposite is the case for the warm phase; the bight is warmer than average and dominated by the San Diegan fauna. There have been three transitions in the PDO over the last century. The most recent oscillation of the PDO caused a regime shift starting in the late 1970's that was completed by the end of the 1982-1984 El Niño, the largest El Niño recorded at that time (Stephens et al. 1984, Holbrook et al. 1997). The transition culminated with the 1982-1984 El Niño that effectively extirpated the

Oregonian fauna from the Southern California Bight.

The strength of the PDO varies annually and the most important phenomenon with respect to this variation is the El Niño Southern Oscillation (ENSO). This oscillation consists of two components, El Niño and La Niña periods. El Niño causes the California Current to weaken and move offshore as warm subtropical water moves into the bight. The rebound from this event is the shift to La Niña, which in effect is manifested as a strengthening of the California Current and generally cooler water in the bight. Either phase of an ENSO generally lasts 1-2 years, depending upon their strength, and are particularly important for understanding fish dynamics in the SCB for a variety of reasons. First, in the El Niño phase, the bight is warmed and vagile warm-water fishes and invertebrates immigrate or recruit into the region (Lea and Rosenblatt 2000, Pondella and Allen 2001). Cold water forms migrate out of the region, move into deeper (cooler) water or are extirpated. During the La Niña phase, the SCB usually, but not always, is cooler than normal, and we observe an increase in cold temperate (Oregonian fauna) organisms through the same processes. Highly mobile organisms will immigrate or emigrate from the bight during these periods; and on smaller spatial scales less vagile organisms may exhibit offshore versus onshore movements. However, the resident fauna tends not to be altered on such short time frames when compared to the magnitude of the PDO. In the decade prior to this study there were three major events that affected the California Current System that need to be explained in order to understand the oceanographic setting of this study period. The first was the 1997-98 El Niño, the strongest recorded event of its kind. This was followed by a series of four cold water years (1999-2002) including the strongest La Niña on record (Schwing et al. 2000, Goericke et al. 2005). The possible return to the cold water phase of the PDO did not occur since 2003-2004 was described as a 'normal' year (Goericke et al. 2005). This normal year turned out to be the beginning of an extended warm phase that has persisted through 2006 (Peterson et al. 2006). Thus, the oceanographic context for this study can best be described as a warm phase of the PDO that has persisted for three years. Prior to this warm phase were four unusually cool years. To determine the current population status of fishes and invertebrates in the SCB requires placing this data into an appropriate long-term context. From an oceanographic standpoint, the influences that were associated with change over time are the PDO, the ENSO, and the associated ocean temperature changes. These oceanographic metrics are interconnected with each other and have effects in the SCB on varying time scales. In order to understand the responses of organisms in the SCB to these various environmental metrics, it is important to realize the general trends for the region (Brooks et al. 2002) and that each taxon may have a unique response to these metrics based upon its life history characteristics and evolution. In addition, to the real time responses these organisms have to oceanographic parameters, anthropogenic influences also have significant effects. Currently, the most extensively studied anthropogenic effects are related to over fishing and the various management actions associated with fishing. In the SCB, all of the top-level predators (with the exception of marine mammals) were over fished during the last seven decades (Ripley 1946, Love et al. 1998, Allen et al. *in press*, Pondella and Allen *in review*). The effects on fisheries were also species specific, as the effort, type of fishery and associated management actions vary case by case.

Some fishes were reserved for recreational anglers (e.g. kelp bass, barred sand bass etc.) as they were historically over fished by commercial fishers (Young 1963); others were primarily commercial species (e.g. anchovies); while others are extracted by both fisheries (e.g. California halibut). Fishery data may or may not reflect actual population trends due to socioeconomic considerations such as market value, effort, management actions, etc. Fishery independent monitoring programs produce the best population time series metrics and also allow non-commercial species to be evaluated.

5. Life History Strategies and egg production

The reproductive mode of a species may determine its habitat needs, dispersal abilities, conditions affecting early survival and recruitment strength (Allen 1982a). In some species, such as surf perch, eggs are retained internally and the young released as juveniles. Many species release pelagic or demersal eggs that either float to the surface or sink to the bottom, strategies that may effect distribution and genetic diversity. In southern California, 40% of the 40 major community members had pelagic eggs and larvae. 18% (all rockfish) were oviparious with pelagic eggs and larvae,15% had demersal eggs and pelagic larvae, 12% were vivarparous and 10% had demersal eggs and larvae, Allen 1982.

Millions of eggs and larvae are entrained in the intakes of the Mandalay and Ormond Beach generating stations each year and there is a need to put these losses into perspective to determine how they may have an impact on the adult fish populations. One approach to this issue is to determine the number of eggs produced by a female fish during its lifespan, and how this compares to the number of eggs or larvae entrained. Table 3.4 presented information on the reproductive biology of fish likely to be entrained at Mandalay and Ormond Beach. To determine the average number of eggs produced by females of each fish species the following formula was used.

Number of eggs produced during life span =

Eggs per spawn X # Spawns per year X (Life span - Age at maturation)

Note: Since the number of eggs per spawn usually increases with age, an average number was selected.

Table 5.1 provides and estimate of the number of eggs produced by fish found in waters off southern California during their lifetimes.

Table 5.1 Estimated number of eggs produced by fish species found in the southern California Bight.

Common Name	# Eggs produced During Lifespan
White Croaker	2,000,000
White Seabass	2,400,000
Queenfish	64,800,000
Speckled Sanddab	275,000
Pacific Halibut	152,000,000
Starry Flounder	65,000,000
Petrale Sole	176,000,000
Rex Sole	1,300,000
Arrowtooth Flounder	63,000,000
Dover Sole	11,040,000
English Sole	15,000,000
Kelp Bass	960,000,000
Northern Anchovy	360,000
Arrow Goby	2,250
Cheekspot Goby	9,600
Yellowfin Goby	285,000
Bay Blenny	28,875

The number of eggs produced by different fish species was then compared with the number of eggs entrained based upon 2006 – 2007 Actual Flow Annual Entrainment (Table 5.2) and the Design Flow Annual Entrainment (Table 5.3).

Table 5.2. Estimate of the number of adult fish required to replace entrained eggs at Mandalay Generating Station based on 2006 – 2007 actual flow annual entrainment. Calculation made by determining onset of maturity in fish, longevity, number of spawns per year and number of eggs produced per spawn. Information gathered from published research.

Egg Identification	2006 - 2007 Actual Flow Annual Entrainment # of Eggs	# Adult fish Required to Produce Equivalent # of Eggs	Possible Species
Drums and croakers	3,877,557	1.9	White Croaker
		1.6	White Seabass
		0.06	Queenfish
Flounder	497,521	0.0033	Pacific halibut
		0.01	Starry Flounder
		0.38	Rex Sole
		0.01	Arrowtooth Flounder
		0.05	Dover Sole

		0.03	English Sole
Petrale Sole	19,484	0.0001	Petrale sole
Speckled sanddab	230,434	0.84	Speckled sanddab
Kelp Bass	177,702	0.0002	Kelp Bass
Righteye flounder	91,545		
California halibut	60,044		
Spotted turbot	23,562		
Queenfish	9,677	0.0001	Queenfish

Table 5.3. Estimate of the number of adult fish required to replace entrained eggs at Mandalay Generating Station based on 2006 – 2007 design flow annual entrainment.

Egg Identification	2006 - 2007 Design Flow Annual Entrainment # of Eggs	# Adult fish Required to Produce Equivalent # of Eggs	Possible Species
Drums and croakers	10,538,391	5.3	White Croaker
		4.4	White Seabass
		0.16	Queenfish
Flounder	1,045,307	0.01	Arrowtooth Flounder
		0.16	Starry Flounder
		0.069	Pacific halibut
		0.38	Rex Sole
		0.05	Dover Sole
		0.03	English Sole
Petrale Sole	43,640	0.0002	Petrale Sole
Speckled sanddab	694,006	0.84	Speckled sanddab
Kelp Bass	337,837	0.0002	Kelp Bass

Table 5.4 Estimate of the number of adult fish required to replace entrained larvae at Mandalay Generating Station based on 2006 – 2007 actual flow annual entrainment. Estimate assumes a mortality rate of 50% from egg to entrained larvae.

Larvae Identification	2006 - 2007 Actual Flow Annual Entrainment # of Larvae	# Adult fish Required to Produce Equivalent # of Larvae
shrimp larvae	15,233,864	*
Arrow goby	10,673,613	9,488
Cheekspot goby	8,890,197	1,852
Bay blenny	5,058,643	350
Yellowfin goby	3,436,603	24
Topsmelt	2,099,575	*
Blackeye goby	888,195	*
California clingfish	619,326	*
Caridean Shrimp	509,367	*

* To be determined

Table 5.5. Estimate of the number of adult fish required to replace entrained eggs at the Ormond Beach Generating Station based on 2006 – 2007 actual flow annual entrainment.

Egg Identification	2006 - 2007 Actual Flow Annual Entrainment # of Eggs	# Adult fish Required to Produce Equivalent # of Eggs	Possible Species
Speckled Sanddab	263,458,961	958	
Queenfish	181,872,663	3	
Drums & Croakers	110,315,049	46	White Seabass
Halibut	11,676,896	0.077	Pacific halibut
Soles & Turbot	7,277,890	0.041	Petrale Sole
		5.6	Rex Sole
		0.659	Dover Sole
White Croaker	6,712,062	55	
Northern Anchovy	19,584,283	54	
English sole	4,363,9232	0.29	
Kelp Bass	2,033,260	0.002	

Table 5.6 Estimate of the number of adult fish required to replace entrained larvae at Ormond Beach Generating Station based on 2006 – 2007 design flow annual entrainment. Estimate assumes a mortality rate of 50% from egg to entrained larvae.

Larvae Identification	2006 - 2007 Design Flow Annual Entrainment # of Larvae	# Adult fish Required to Produce Equivalent # of Larvae
shrimp larvae	702,861,560	*
Northern Anchovy	14,153,517	19.658
Crab megalopa	11,809,905	*
White croaker	4,837,491	1.09
Bay Blenny	1,717,334	39.737
Queenfish	1,153,662	0.009
Speckled sanddab	1,117,762	2.032
California halibut	1,204,039	0.004 (Pacific halibut)
English sole	808,636	0.027
Arrow goby	833,170	185.149
Cheekspot goby	742,468	36.67
Yellow goby	454,196	0.797

* To be determined

Tables 5.2 through 5.7 provide a link between the number of larvae lost through entrainment to the number of adults required to produce them. It can be seen that the large numbers (in the millions) of larvae entrained translate to the reproductive effort of a small number of fish.

Life spans and reproductive output differ among species. For long- term survival, the reproductive output and longevity of each individual must be such that it replaces itself during its lifetime. Shore-lived species must have a reproductive strategy that accomplishes rapid replacement (3 – 4 years for speckled sanddab) while long-lived species such as rockfish (80 years plus) may have a less efficient reproduction strategy but a longer period to achieve replacement.

Recruitment for marine species in the southern California Bight may be sporatic since the boundary between the cooler Oregonian and warmer San Diegan zoogeographic zones is constantly shifting. Variation in recruitment is also species specific. As a rule, species at the edge of their geographic range recruit more sporadically than those near the center. Settlement is also a function of spawning success, changes in oceanographic conditions (ex. Upwelling), that affect transport, food availability and temperature, and ultimately larval survival, and available of suitable conditions for settling larvae.

6 Summary

Impingement Mortality and/or Entrainment Characterization Studies (IMECS) conducted at Mandalay and Ormond Beach Generating Stations in 2006 – 2007 c characterized temporal and spatial variations in abundance and variety of entrained eggs and larvae of fishes and invertebrates. Estimates of the number of fish remaining after one year and the reproductive effort of adults shows that only small number of fish species and taxa are affected by generating station entrainment. Oceanographic and climate conditions that influence waters of the southern California Bight have the greatest impact on fluctuations of fish populations.

Long-term monitoring of ichthyoplankton adjacent to other coastal power plants in California has not demonstrated that entrainment has a detectable negative impact on adjacent fish or invertebrate populations. (EPRI 2008). This has been the case for facilities that draw cooling water from enclosed bays and lagoons and for those located on the open coast. Like Mandalay and Ormond Beach other IMECS studies at coastal generating stations in southern California (Tenera 2008, 2008) indicated that 95% of entrainment losses were of commonly occurring forage species not utilized by commercial or sport fisheries. Populations of these species adjacent to power plants were determined to be similar to those found in distant habitats not influenced by the facilities. Life history and behavior of the most commonly entrained species likely reduces impacts from once through cooling on local populations. Other factors may have a greater influence on the abundance of these populations and there are numerous examples of how temperature, larval density, and habitat availability work to limit fish abundance. Changes in fish species and abundance reflect shifts in ocean circulation patterns and temperatures. These variables must be considered when examining fish populations within the SCB to avoid confusing natural changes with anthropogenic effects. Analysis by researchers at USEPA (Newbold and Iovanna 2007) suggests that if density constrains one or more stages of the life cycle, the loss of larvae to entrainment will have small effects at the population level.

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Appendix Table 3.9. Biology of Entrained fish

Common Name	Scientific Name	Age of Maturity	Length of Maturity	Spawning Time of Year	Spawning Time of Day	Number of Spawns per Year	Number of Eggs per Spawn	Survival Ratio of Eggs/ Larvae	Life Span of Fish
Kelp Bass	*Paralabrax clathratus*	M: between 2-4yrs F: between 2-5yrs **Love, 1996**	M: All by 26cm F: All by 27cm **Love, 1996**	Late Spring to early Fall **Love, 1996**	Late afternoon and evening hours **Oda, 1993**	Capable of spawning daily **Oda, 1993**	Average 81,000 eggs per batch **Oda, 1993**		33 years **Love et al. 1996**
Northern Anchovy	*Engraulis mordax*	Some mature by the end of year 1, all mature by age 4 **Love, 1991**	At 110-130 mm by 1-yr/ At 152 mm by 4-yr **Clark and Phillips 1952, Hart 1973**	Year-round spawning with peaks during late Winter to Spring **Love, 1996; Moser, 1996**	Late night to early morning **Parrish, 1986**	Age dependent. 1st yr females average 5.3/ 4th yr females average 23.5 spawnings Average among all females, 15.1 **Parrish, 1986**	Typical 1-yr old female: 5,896 eggs. Typical 4-yr old female 12,895 eggs. **Parrish, 1986**		7 years **Frey, 1971**
White Croaker	*Genyonemus lineatus*	Over 50% by 1-yr All by 3-4yrs **Love, 1984**	M: Over 50% by 14cm F: Over 50% by 15cm All mature by 19cm **Love, 1984**	Can occur throughout the year/ Principal spawning occurrs from November to April **Love, 1984**		18-24 times a season **Love, 1984**	range from 800 to 37,200 eggs Age dependent. **Love, 1984**		13 years **Love, 1996**
Yellowfin Goby	*Acanthogobius flavimanus*	2-3yrs **Moyle, 1976**	Mean length of 167.4mm **Bell, 1987**	December through July **Dotsu and Mito,1955**			6,000- 32,000 eggs **Miyazaki, 1940**		3- 4 years **Miyazaki, 1940**
Bay Blenny	*Hypsblennius gentilis*	within 1-yr **Stephens, 1969**		From early Spring to Spetember **Stephens et al. 1970**		spawn 3-4 times over a period of several weeks **Stephens et al. 1970**	300-3,000 eggs varies proportionately with size **Stephens et al. 1970**	Daily larval survival was as 0.8875 **Stephens, 1969**	6-7 years **Stephens, 1969**
Speckled Sanddab	*Citharichthys stigmaeus*	F: 2-yr **Ford, 1965**	F: Average of 70 to 80mm **Ford, 1965** Overall 6.4cm **Love, 1996**	Nearly year round spawning **Craig, 2004** Principal spawning from April to September **Ford, 1965**	Early morning **Ford, 1965**	Multiple spawnings per season **Arora, 1951 and Ford, 1965**	Estimated number of eggs spawned were 4,200 at lengths of 85-90mm, 12,100 at 109.5-110.5mm and 22,500 at lengths greater than 129mm		3.5 years **Love, 1996**

							Ford, 1965		
Pacific Sanddab	*Citharichthys sordidus*	F: 3-yr **Arora, 1951**	F: Average of 190mm **Arora, 1951**	March to May **Love, 1996**	Early morning **Ford, 1965**	Two **Love, 1996**			11 years **Love, 1996**
White Seabass	*Atractoscion nobilis*	F: Begin maturing by 4-yrs M:Some at 3-yrs **DFG, 2001**	All mature at 80cm **Clark, 1930**	April to August **DFG, 2001**	Night **DFG, 2001**				Up to 16 years **Thomas, 1968**
Queenfish	*Seriphus politus*	First Spring or second Summer following birth **DeMartini, 1981**	F: 10.0 to 10.5cm **DeMartini, 1981**	March to August **DeMartini, 1981**	Spawning takes place between late afternoon or morning/ Peak spawning during the moons first quarter **DeMartini, 1981**	Once a week/ The largest repeat spawners produce about 12 to 24 batches of eggs during their respective spawning seasons their respective spawning season **DeMartini, 1981**	Average size female produces about 300,000 eggs in a year/ fecundity increases with body size. **DeMartini, 1981**		
California Halibut	*Paralichthys californicus*	M: 2-3yrs F: 4-5yrs **DFG**	300+mm **Miller and Lea, 1972**	February to July **Fitch and Lavenberg, 1971**					30 years **Love, 1996**
Longfin Sanddab	*Citharichthys xanthostigma*	F: 3-yrs **DFG**	F: About 7.5 inches **DFG**	July to September **DFG**		Multiple spawnings **DFG**			
Pacific Halibut	*Hippoglossus stenolepis*	F: 12-yrs M: 8-yrs **NOAA, 2009**	F: 90-140cm M: 70-110cm **Novikov, 1964**	November to the end of March **Bell and St-Pierre, 1970**		Spawn only once per year **NOAA, 2009**	A 250 pound female can produce about 4 million eggs. **NOAA, 2009**		Up to 50 years. **NOAA, 2009**
Starry Flounder	*Platichthys stellatus*	M: 2-3yrs F: 3-4yrs **Love, 1996 and Emmett et al. 1991**	M: 36.83cm F: 40.64cm **DFG**	February through April **Love, 1996**		Females spawn once a year **Orcutt, 1950**	900,000 to 11,000,000 eggs **Orcutt, 1950; Garrison and Miller 1982;** **Love ,1996**		M: 24 years F: 17 years Campana 1984 in Emmett **et al. 1991**
Petrale Sole	*Eopsetta jordani*	M:50% mature at 7-yr F:50% mature at 8-yr **Love, 1996**	M: all mature by 40.64cm F: all mature by 45.7cm **Love, 1996**	From about November through March **Porter, 1964**		Females spawn once a year **Porter, 1964**	400,000 to 1,200,000 eggs **Love, 1996**		Up to 30 years **Sager and Summler , 1982**
California Tonguefish	*Syumphurus atricauda*		12.7cm **Love, 1996**	May to October, July and August(peak) **Love, 1996**	Night **Love, 1996**				

Fantail Sole	*Xystreurys liolepis*		160mm **Miller and Lea, 1972**	Summer and Fall **Kramer, 1991**					
Hornyhead Turbot	*Pleuronichthys verticalis*		142mm **Goldberg, 1982**	From March until August **Budd, 1940** Possibly year round spawners **Goldberg, 1982**					
Spotted Turbot	*Pleuronichthys ritteri*		142mm **Miller and Lea, 1972**	Possibly year round spawners Principal seasons are Spring and Summer **Kramer, 1991**					
Diamond Turbot	*Hypsopetta guttulata*		160mm **Miller and Lea, 1972**	Winter, Fall **Kramer, 1991**					
Cheekspot Goby	*Ilypnus gilberti*	50% mature after 8 months **Matarese et al. 1989, Moser et al. 1996**		Spawns year-round in bays and estuaries **TENERA Enviromental,2005**		2–5 per yr **Brothers, 1975**	From 225–1,030 eggs per batch/ dependent on age and size of females **Brothers, 1975**	estimated a 60-day larval mortality of 98.6%/ average daily survival at 0.93 **Brothers, 1975**	4 years **Brothers, 1975**
Arrow Goby	*Clevelandia ios*	50% mature after 16-18 months **Materese et al. 1989, Moser et al. 1996**	Overall 2.9cm **Emmett et al., 1991** F: 3.4cm all are mature **Prasad, 1948 in Emmett et al. 1991**	March to June **Eschmeyer and Herald, 1983** May Spawn year-round **Brothers, 1975 in Emmett et al. 1991**		2–5 per yr **Brothers, 1975**	From 225–750 eggs per batch/ denpendent on age and size of females **Brothers, 1975**	estimated a 60-day larval mortality of 98.3%/ average daily survival at 0.93 **Brothers, 1975**	2 to 3 years **Prasad 1948 in Emmett et al., 1991**
Rex Sole	*Glyptocephalus zachirus*	M: 5-yr F: 9-yrs **Love, 1996**	M: 21.6cm F: 30.5cm **Love, 1996**	January- July peak months April-March **Love, 1996**		Spawn once per year **Moser, 1967**	3,900–238,000 eggs **Love, 1996**		24+ years **Love, 1996**
Arrowtooth Flounder	*Atheresthes bothybius*	M: 3 to 7 years F: 4-8 years **NOAA, 2009**	F: 50% mature at 44-47cm M: 50% mature at 29-42cm **Fargo et al. 1981; Ricky, 1995; Zimmerman, 1997**	Fall to early Spring. **NOAA, 2009**		Spawn multiple times during a spawning season. **NOAA, 2009**	250,000-2,400,000 eggs per spawning season **Fargo et al. 1981; Rickey, 1995; Zimmermann, 1997**		Up to 27 years **NOAA, 2009**
Dover Sole	*Microstomus pacificus*	M: 7-yr (all mature) **Hagerman, 1952** F: 11-yr (all mature) **Hagerman, 1952; Harry, 1959;**	M: all mature by 40.6cm **Love, 1996** F: all mature by 45.7cm **Love, 1996**	November to March **Harry, 1959; Demory, 1975; Garrison and Miller, 1982; Hirschberger and Smith, 1983**		Spawn multiple times in a single spawning season. **NOAA, 2009**	ranges from 37,000 eggs for a 36cm female to 265,800 eggs for a 57.5cm female **Harry, 1959; Frey, 1971**		M: 58 years F: 53 years **Love, 1996**

		Demory, 1975							
Deepsea Sole	*Embassichthys bathybius*								
English Sole	*Parophrus vetulus*	M: 2-yr **Harry, 1959** F: 3–5yrs **Love, 1996**	M: 29.2cm **Love, 1996** F: 35.6cm **Love, 1996**	October to May **Frey, 1971**		1+ **Love, 1996**	150,000 to 2,100,000 eggs **Love, 1996**		M: At least 16 years F: At least 20 years **NOAA, 2009**
Sand Sole	*Psettichthys menanostictus*	M: 2-yr F: 2-3yrs **Love, 1996**	M: 250mm F: 310mm **Pearson**	January- July **Love, 1996**			a female of 26cm may produce 900,000 eggs, while a fish of 37cm may produce 1,400,000 **Garrison and Miller, 1982**		10 years **Stickney et al. 1995**
Rock Sole	*Lepidopsetta bilineata*	4 to 7 years **NOAA, 2009**	M: 36.8cm F: 43.2cm **Love, 1996**	February- March **Love, 1996**			400,000 to 1,300,000 eggs **Love, 1996**		M: 22 years F: 15 years **Love, 1996**
Curlfin Turbot	*Pleuronichthys decurrens*			From March until August **Budd, 1940**					
C-O Turbot	*Pleuronichthys coenosus*			March to August **Love, 1996**					
Butter Sole	*Isopsetta isolepis*	M: 2-yr F: 3-yr **Love, 1996**	M: 10.2cm F: 25.4cm **Love, 1996**	February to April **Love, 1996**			350,000 to 1,000,000 eggs **Love, 1996**		M: 10 years F: 11 years **Love, 1996**
Shortfin Corvina	*Cynoscian parviminnis*								
Yellowfin Croaker	*Umbrina roncador*	4 years **Love, 1996**	23cm **Love, 1996**	During Summer months **DFG, 2001**					15 years **Pondella et al. in press**
Black Croaker	*Cheilotrema saturum*	2 to 3 years **Fitch and Lavenberg, 1975; Love, 1996**	23cm **Fitch and Lavenberg, 1975; Love, 1996**	Spring to Summer **Miller, 2008**					Up to 21 years **Miller, 2008**
Bigmouth Sole	*Hippoglossina stomata*		F: 162mm **Goldberg, 1982**	Summer- Fall **Goldberg, 1982**					
California Corbina	*Menticirrhus undulatus*	2 to 3 years **Oliphant, 1992a**	25-30 cm **Oliphant, 1992a**						8 years **Joseph, 1962**
Spotfin Croaker	*Roncador stearnsii*	2 to 3 years **Oliphant, 1992b**	23- 32 cmm **Oliphant, 1992b**						22 years **Joseph, 1962**

Table 3.10 Ormond Beach Entrainment

OBGS Fish Growth and Survival.xls Table 3.10

Ormond Beach Generating Station Proteus

Egg & Larval Entrainment

Hatch Size, Growth, Mortality, and Survival Calculations

Species	Average Hatch Length mm	Growth Rate mm / day	Larval Duration Days	Average Settlement Size mm	
Queenfish	2.9	0.2	19	3.8	
White Croaker	1.5	0.2	24	4.8	
Speckled Sanddab	2.0	0.1	342	30	
CA Tonguefish	3.5			25	
Turbot				15	
California Halibut	1.9	0.4	25	10	Allen 1988
English Sole	2.8	0.2	80	20	
N Anchovy	2.5	0.4	70	35	

Egg Entrainment

Species	2006 - 2007 Ormond Actual Flow Annual **Egg** Entrainment	# Fish Surviving to Metamorphosis assuming Mortality Rate of 0.5 per day	Mortality in 1st year of Growth
Queenfish	181,872,653	347	42%
Drums & Croakers**	110,315,049	210	42%
White Croaker	6,712,062	7	42%
Speckled Sanddab	263,458,961	0	50%
CA Tonguefish	15,850,159		
Turbot (Spotted)	2,544,985		
N Anchovy	19,584,283	0	50%

* Calculated Survival rate based on Average Instantaneous Natural Mortality Rate of 0.5 / day
Mortality rate range 0.05 - 1.0 / day for marine fish McGurk 1989.

** Drums & Croaker survival if Mortality similar to Queenfish

Larval Entrainment

Species	2006 - 2007 Ormond Actual Flow Annual **Larvae** Entrainment	# Fish Surviving to Metamorphosis assuming Mortality Rate of 0.5 per day	Mortality in 1st year of Growth
Queenfish	313,393	1	42%
White Croaker	325,972	0	42%
Speckled Sanddab	140,877	0	42%
CA Tonguefish		0	50%
Turbot			
California halibut	220,669	0	20%

N Anchovy	3,424,889	0

Species	Average Hatch Length mm	Length at OBGS Entrainment mm	Amount of Growth since hatch mm	Calculated Age of larvae Days	# Days to Settlement
Queenfish	2.9	3.3	0.4	2.0	17
White Croaker	1.5	3.0	1.5	7.5	17
Speckled Sanddab	2.0	9.5	7.5	85.5	257
CA Tonguefish	3.5				0
California Halibut	1.9	6.8	4.9	12.3	13
English Sole	2.8	3.2	0.4	1.9	78
N Anchovy	2.5	16.0	13.5	33.8	36

Table 3.10 Continued

Table 3.10

Natural Mortality Rate and Survival

Proteus

Calculations based on an average Instantaneous Mortality Rate (M) of 0.5 / day, the average for many marine fish (McGurk 1986)

Queenfish

Larval to metamorphosis, M =	0.5	/ day
Metamorphosis to year 1	0.42	/ day
Larvae duration	19	days
# Larvae Remaining	1.9E-06	larvae to metamorphosis

White Croaker

Larval to metamorphosis, M =	0.5	/ day
Metamorphosis to year 1	0.42	/ day
Larvae duration	80	days
# Larvae Remaining	6.0E-08	larvae to metamorphosis

Speckled Sanddab

Larval to metamorphosis, M =		0.5	/ day
Metamorphosis to year 1		0.42	/ day
Larvae duration	Growth		days
# Larvae Remaining		4.3E-78	larvae to metamorphosis

Northern Anchovy

Larval to metamprphosis, M =	0.5	/ day
Metamorphosis to year 1	0.42	/ day
Larvae duration	70	days
# Larvae Remaining	8.5E-22	larvae to metamorphosis

California Halibut

Larval to metamorphosis, M =	0.5	/ day

Metamorphosis to year 1	0.42	/ day
Larvae duration	25	days
# Larvae Remaining	3.0E-08	larvae to metamorphosis

Table 3.10 Continued

Queenfish

Calculations based on Average Instantaneous Mortality Rate (M), per day, found in many marine fish (McGurk 1986)

		Average	
	M =	0.5	/day
	Starting #	End #	
Day	Larvae	Larvae	
1	1.000000	0.500000	
2	0.500000	0.250000	
3	0.250000	0.125000	
4	0.125000	0.062500	
5	0.062500	0.031250	
6	0.031250	0.015625	
7	0.015625	0.007813	
8	0.007813	0.003906	
9	0.003906	0.001953	
10	0.001953	0.000977	
11	0.000977	0.000488	
12	0.000488	0.000244	
13	0.000244	0.000122	
14	0.000122	0.000061	
15	0.000061	0.000031	
16	0.000031	0.000015	
17	0.000015	0.000008	
18	0.000008	0.000004	
19	0.000004	0.000002	

Table 3.10 Continued

Speckled Sanddab

Calculations based on Average Instantaneous Mortality Rate (M), per day, found in many marine fish (McGurk 1986)

		Average	
	M =	0.5	/day
	Starting #	End #	
Day	Larvae	Larvae	
1	1.0E+00	5.0E-01	
2	5.0E-01	2.5E-01	
3	2.5E-01	1.3E-01	
4	1.3E-01	6.3E-02	
5	6.3E-02	3.1E-02	
6	3.1E-02	1.6E-02	
7	1.6E-02	7.8E-03	
8	7.8E-03	3.9E-03	
9	3.9E-03	2.0E-03	
10	2.0E-03	9.8E-04	
11	9.8E-04	4.9E-04	
12	4.9E-04	2.4E-04	
13	2.4E-04	1.2E-04	
14	1.2E-04	6.1E-05	
15	6.1E-05	3.1E-05	
16	3.1E-05	1.5E-05	
17	1.5E-05	7.6E-06	
18	7.6E-06	3.8E-06	
19	3.8E-06	1.9E-06	
20	1.9E-06	9.5E-07	
21	9.5E-07	4.8E-07	
22	4.8E-07	2.4E-07	
23	2.4E-07	1.2E-07	
24	1.2E-07	6.0E-08	
25	6.0E-08	3.0E-08	
26	3.0E-08	1.5E-08	
27	1.5E-08	7.5E-09	
28	7.5E-09	3.7E-09	
29	3.7E-09	1.9E-09	
30	1.9E-09	9.3E-10	
31	9.3E-10	4.7E-10	
32	4.7E-10	2.3E-10	
33	2.3E-10	1.2E-10	
34	1.2E-10	5.8E-11	
35	5.8E-11	2.9E-11	
36	2.9E-11	1.5E-11	
37	1.5E-11	7.3E-12	
38	7.3E-12	3.6E-12	
39	3.6E-12	1.8E-12	
40	1.8E-12	9.1E-13	
41	9.1E-13	4.5E-13	
42	4.5E-13	2.3E-13	
43	2.3E-13	1.1E-13	
44	1.1E-13	5.7E-14	

45	5.7E-14	2.8E-14
46	2.8E-14	1.4E-14
47	1.4E-14	7.1E-15
48	7.1E-15	3.6E-15
49	3.6E-15	1.8E-15
50	1.8E-15	8.9E-16
51	8.9E-16	4.4E-16
52	4.4E-16	2.2E-16
53	2.2E-16	1.1E-16
54	1.1E-16	5.6E-17
55	5.6E-17	2.8E-17
56	2.8E-17	1.4E-17
57	1.4E-17	6.9E-18
58	6.9E-18	3.5E-18
59	3.5E-18	1.7E-18
60	1.7E-18	8.7E-19
61	8.7E-19	4.3E-19
62	4.3E-19	2.2E-19
63	2.2E-19	1.1E-19
64	1.1E-19	5.4E-20
65	5.4E-20	2.7E-20
66	2.7E-20	1.4E-20
67	1.4E-20	6.8E-21
68	6.8E-21	3.4E-21
69	3.4E-21	1.7E-21
70	1.7E-21	8.5E-22
71	8.5E-22	4.2E-22
72	4.2E-22	2.1E-22
73	2.1E-22	1.1E-22
74	1.1E-22	5.3E-23
75	5.3E-23	2.6E-23
76	2.6E-23	1.3E-23
77	1.3E-23	6.6E-24
78	6.6E-24	3.3E-24
79	3.3E-24	1.7E-24
80	1.7E-24	8.3E-25
81	8.3E-25	4.1E-25
82	4.1E-25	2.1E-25
83	2.1E-25	1.0E-25
84	1.0E-25	5.2E-26
85	5.2E-26	2.6E-26
86	2.6E-26	1.3E-26
87	1.3E-26	6.5E-27
88	6.5E-27	3.2E-27
89	3.2E-27	1.6E-27
90	1.6E-27	8.1E-28
91	8.1E-28	4.0E-28
92	4.0E-28	2.0E-28
93	2.0E-28	1.0E-28

94	1.0E-28	5.0E-29
95	5.0E-29	2.5E-29
96	2.5E-29	1.3E-29
97	1.3E-29	6.3E-30
98	6.3E-30	3.2E-30
99	3.2E-30	1.6E-30
100	1.6E-30	7.9E-31
101	7.9E-31	3.9E-31
102	3.9E-31	2.0E-31
103	2.0E-31	9.9E-32
104	9.9E-32	4.9E-32
105	4.9E-32	2.5E-32
106	2.5E-32	1.2E-32
107	1.2E-32	6.2E-33
108	6.2E-33	3.1E-33
109	3.1E-33	1.5E-33
110	1.5E-33	7.7E-34
111	7.7E-34	3.9E-34
112	3.9E-34	1.9E-34
113	1.9E-34	9.6E-35
114	9.6E-35	4.8E-35
115	4.8E-35	2.4E-35
116	2.4E-35	1.2E-35
117	1.2E-35	6.0E-36
118	6.0E-36	3.0E-36
119	3.0E-36	1.5E-36
120	1.5E-36	7.5E-37
121	7.5E-37	3.8E-37
122	3.8E-37	1.9E-37
123	1.9E-37	9.4E-38
124	9.4E-38	4.7E-38
125	4.7E-38	2.4E-38
126	2.4E-38	1.2E-38
127	1.2E-38	5.9E-39
128	5.9E-39	2.9E-39
129	2.9E-39	1.5E-39
130	1.5E-39	7.3E-40
131	7.3E-40	3.7E-40
132	3.7E-40	1.8E-40
133	1.8E-40	9.2E-41
134	9.2E-41	4.6E-41
135	4.6E-41	2.3E-41
136	2.3E-41	1.1E-41
137	1.1E-41	5.7E-42
138	5.7E-42	2.9E-42
139	2.9E-42	1.4E-42
140	1.4E-42	7.2E-43
141	7.2E-43	3.6E-43
142	3.6E-43	1.8E-43

143	1.8E-43	9.0E-44
144	9.0E-44	4.5E-44
145	4.5E-44	2.2E-44
146	2.2E-44	1.1E-44
147	1.1E-44	5.6E-45
148	5.6E-45	2.8E-45
149	2.8E-45	1.4E-45
150	1.4E-45	7.0E-46
151	7.0E-46	3.5E-46
152	3.5E-46	1.8E-46
153	1.8E-46	8.8E-47
154	8.8E-47	4.4E-47
155	4.4E-47	2.2E-47
156	2.2E-47	1.1E-47
157	1.1E-47	5.5E-48
158	5.5E-48	2.7E-48
159	2.7E-48	1.4E-48
160	1.4E-48	6.8E-49
161	6.8E-49	3.4E-49
162	3.4E-49	1.7E-49
163	1.7E-49	8.6E-50
164	8.6E-50	4.3E-50
165	4.3E-50	2.1E-50
166	2.1E-50	1.1E-50
167	1.1E-50	5.3E-51
168	5.3E-51	2.7E-51
169	2.7E-51	1.3E-51
170	1.3E-51	6.7E-52
171	6.7E-52	3.3E-52
172	3.3E-52	1.7E-52
173	1.7E-52	8.4E-53
174	8.4E-53	4.2E-53
175	4.2E-53	2.1E-53
176	2.1E-53	1.0E-53
177	1.0E-53	5.2E-54
178	5.2E-54	2.6E-54
179	2.6E-54	1.3E-54
180	1.3E-54	6.5E-55
181	6.5E-55	3.3E-55
182	3.3E-55	1.6E-55
183	1.6E-55	8.2E-56
184	8.2E-56	4.1E-56
185	4.1E-56	2.0E-56
186	2.0E-56	1.0E-56
187	1.0E-56	5.1E-57
188	5.1E-57	2.5E-57
189	2.5E-57	1.3E-57
190	1.3E-57	6.4E-58
191	6.4E-58	3.2E-58

192	3.2E-58	1.6E-58
193	1.6E-58	8.0E-59
194	8.0E-59	4.0E-59
195	4.0E-59	2.0E-59
196	2.0E-59	1.0E-59
197	1.0E-59	5.0E-60
198	5.0E-60	2.5E-60
199	2.5E-60	1.2E-60
200	1.2E-60	6.2E-61
201	6.2E-61	3.1E-61
202	3.1E-61	1.6E-61
203	1.6E-61	7.8E-62
204	7.8E-62	3.9E-62
205	3.9E-62	1.9E-62
206	1.9E-62	9.7E-63
207	9.7E-63	4.9E-63
208	4.9E-63	2.4E-63
209	2.4E-63	1.2E-63
210	1.2E-63	6.1E-64
211	6.1E-64	3.0E-64
212	3.0E-64	1.5E-64
213	1.5E-64	7.6E-65
214	7.6E-65	3.8E-65
215	3.8E-65	1.9E-65
216	1.9E-65	9.5E-66
217	9.5E-66	4.7E-66
218	4.7E-66	2.4E-66
219	2.4E-66	1.2E-66
220	1.2E-66	5.9E-67
221	5.9E-67	3.0E-67
222	3.0E-67	1.5E-67
223	1.5E-67	7.4E-68
224	7.4E-68	3.7E-68
225	3.7E-68	1.9E-68
226	1.9E-68	9.3E-69
227	9.3E-69	4.6E-69
228	4.6E-69	2.3E-69
229	2.3E-69	1.2E-69
230	1.2E-69	5.8E-70
231	5.8E-70	2.9E-70
232	2.9E-70	1.4E-70
233	1.4E-70	7.2E-71
234	7.2E-71	3.6E-71
235	3.6E-71	1.8E-71
236	1.8E-71	9.1E-72
237	9.1E-72	4.5E-72
238	4.5E-72	2.3E-72
239	2.3E-72	1.1E-72
240	1.1E-72	5.7E-73

241	5.7E-73	2.8E-73
242	2.8E-73	1.4E-73
243	1.4E-73	7.1E-74
244	7.1E-74	3.5E-74
245	3.5E-74	1.8E-74
246	1.8E-74	8.8E-75
247	8.8E-75	4.4E-75
248	4.4E-75	2.2E-75
249	2.2E-75	1.1E-75
250	1.1E-75	5.5E-76
251	5.5E-76	2.8E-76
252	2.8E-76	1.4E-76
253	1.4E-76	6.9E-77
254	6.9E-77	3.5E-77
255	3.5E-77	1.7E-77
256	1.7E-77	8.6E-78
257	8.6E-78	4.3E-78

Table 3.10 Continued

Northern Anchovy

Calculations based on Average Instantaneous Mortality Rate (M), per day, found in many marine fish (McGurk 1986)

			Average	
		M =	0.5	/day
	Starting #		End #	
Day	Larvae		Larvae	
1		1.0E+00	5.0E-01	
2		5.0E-01	2.5E-01	
3		2.5E-01	1.3E-01	
4		1.3E-01	6.3E-02	
5		6.3E-02	3.1E-02	
6		3.1E-02	1.6E-02	
7		1.6E-02	7.8E-03	
8		7.8E-03	3.9E-03	
9		3.9E-03	2.0E-03	
10		2.0E-03	9.8E-04	
11		9.8E-04	4.9E-04	
12		4.9E-04	2.4E-04	
13		2.4E-04	1.2E-04	
14		1.2E-04	6.1E-05	
15		6.1E-05	3.1E-05	
16		3.1E-05	1.5E-05	
17		1.5E-05	7.6E-06	

18	7.6E-06	3.8E-06
19	3.8E-06	1.9E-06
20	1.9E-06	9.5E-07
21	9.5E-07	4.8E-07
22	4.8E-07	2.4E-07
23	2.4E-07	1.2E-07
24	1.2E-07	6.0E-08
25	6.0E-08	3.0E-08
26	3.0E-08	1.5E-08
27	1.5E-08	7.5E-09
28	7.5E-09	3.7E-09
29	3.7E-09	1.9E-09
30	1.9E-09	9.3E-10
31	9.3E-10	4.7E-10
32	4.7E-10	2.3E-10
33	2.3E-10	1.2E-10
34	1.2E-10	5.8E-11
35	5.8E-11	2.9E-11
36	2.9E-11	1.5E-11
37	1.5E-11	7.3E-12
38	7.3E-12	3.6E-12
39	3.6E-12	1.8E-12
40	1.8E-12	9.1E-13
41	9.1E-13	4.5E-13
42	4.5E-13	2.3E-13
43	2.3E-13	1.1E-13
44	1.1E-13	5.7E-14
45	5.7E-14	2.8E-14
46	2.8E-14	1.4E-14
47	1.4E-14	7.1E-15
48	7.1E-15	3.6E-15
49	3.6E-15	1.8E-15
50	1.8E-15	8.9E-16
51	8.9E-16	4.4E-16
52	4.4E-16	2.2E-16
53	2.2E-16	1.1E-16
54	1.1E-16	5.6E-17
55	5.6E-17	2.8E-17
56	2.8E-17	1.4E-17
57	1.4E-17	6.9E-18
58	6.9E-18	3.5E-18
59	3.5E-18	1.7E-18
60	1.7E-18	8.7E-19
61	8.7E-19	4.3E-19
62	4.3E-19	2.2E-19
63	2.2E-19	1.1E-19
64	1.1E-19	5.4E-20
65	5.4E-20	2.7E-20
66	2.7E-20	1.4E-20

67	1.4E-20	6.8E-21
68	6.8E-21	3.4E-21
69	3.4E-21	1.7E-21
70	1.7E-21	8.5E-22

Table 3.10 Continued

California Halibut

Calculations based on Average Instantaneous Mortality Rate (M), per day, found in many marine fish (McGurk 1986)

		Average	
	M =	0.5	/day
	Starting #	End #	
Day	Larvae	Larvae	
1	1.0E+00	5.0E-01	
2	5.0E-01	2.5E-01	
3	2.5E-01	1.3E-01	
4	1.3E-01	6.3E-02	
5	6.3E-02	3.1E-02	
6	3.1E-02	1.6E-02	
7	1.6E-02	7.8E-03	
8	7.8E-03	3.9E-03	
9	3.9E-03	2.0E-03	
10	2.0E-03	9.8E-04	
11	9.8E-04	4.9E-04	
12	4.9E-04	2.4E-04	
13	2.4E-04	1.2E-04	
14	1.2E-04	6.1E-05	
15	6.1E-05	3.1E-05	
16	3.1E-05	1.5E-05	
17	1.5E-05	7.6E-06	
18	7.6E-06	3.8E-06	
19	3.8E-06	1.9E-06	
20	1.9E-06	9.5E-07	
21	9.5E-07	4.8E-07	
22	4.8E-07	2.4E-07	
23	2.4E-07	1.2E-07	
24	1.2E-07	6.0E-08	
25	6.0E-08	3.0E-08	

Table 3.10 Continued

White Croaker

Calculations based on Average Instantaneous Mortality Rate (M),
per day, found in many marine fish (McGurk 1986)

	M =	0.5	/day
	Starting #	End #	
Day	Larvae	Larvae	
1	1.0E+00	5.0E-01	
2	5.0E-01	2.5E-01	
3	2.5E-01	1.3E-01	
4	1.3E-01	6.3E-02	
5	6.3E-02	3.1E-02	
6	3.1E-02	1.6E-02	
7	1.6E-02	7.8E-03	
8	7.8E-03	3.9E-03	
9	3.9E-03	2.0E-03	
10	2.0E-03	9.8E-04	
11	9.8E-04	4.9E-04	
12	4.9E-04	2.4E-04	
13	2.4E-04	1.2E-04	
14	1.2E-04	6.1E-05	
15	6.1E-05	3.1E-05	
16	3.1E-05	1.5E-05	
17	1.5E-05	7.6E-06	
18	7.6E-06	3.8E-06	
19	3.8E-06	1.9E-06	
20	1.9E-06	9.5E-07	
21	9.5E-07	4.8E-07	
22	4.8E-07	2.4E-07	
23	2.4E-07	1.2E-07	
24	1.2E-07	6.0E-08	

Table 3.11 Mandalay Entrainment

Mandalay Generating Station **Table 3.11** Proteus
Larval Entrainment
CIQ Goby Complex (Arrow, Cheekspot, and Shadow Gobies)
Hatch Size, Growth and Mortality

Average Hatch size 2 - 3 mm Average = 2.5 mm Hatch Length

Aveage growth rate = 0.16 mm / day for 60 days from hatch to settlement

	Length at	Amount of		
Average	MGS	Growth	Calculated	# Days to

Species	Hatch Length mm	Entrainment mm	since hatch mm	Age of larvae Days	Settlement
Arrow Goby	2.5	3.55	1.05	6.6	53
Cheekspot Goby	2.5	3.33	0.83	5.2	55
Bay Goby	2.5	4.99	2.49	15.6	44
Blackeye Goby	2.5	2.92	0.42	2.6	57
Yellowfin Goby	2.5	4.85	2.35	14.7	45

CIQ Average Daily Survival over 60 days = 0.93 / day

this is equivalent to an average mortality of 98% over 60 days

Approximately 90% mortality over 55 days, then

Species	Mandalay Actual Flow Annual Entrainment	@ 90% mortality #Larvae that would have survived to settlement	Mortality in 1st year of Growth
Arrow Goby	10,673,613	1,067,361	99%
Cheekspot Goby	8,890,197	889,020	70%
Bay Goby	19,775	1,978	65%
Blackeye Goby	888,195	88,820	70%
Yellowfin Goby	3,436,603	343,660	70%

Subsequend mortality rates are 25% per year.

Note: All adult gobies are small (5 - 15 cm) and inhaibat crevices in the substrate.
None of these species are fished. The yellow goby is an introduced species.

Shrimp larvae

15,233,862 shrimp larvae were entrained in 2006 - 2007 IMECS survey

If survival of all "shrimp" is similar to one member of this group
Pink or Shrimp, Pandalus jordani, then
survival to settlement would be between 0.5 - 2%.

1% survival to settlement = 152,339 settled juveniles

Mandalay **Table 3.11 Continued**

3,887,557 eggs from "Drums and Croakers" entrained in 2006 - 2007 IMECS survey

Natural Mortality Rate and Survival

Calculations based on an average Instantaneous Mortality Rate (M)
of 0.5 / day, the average for many marine fish (McGurk 1986)

Queenfish

Larval to metamprphosis,M =	0.5	/ day
Metamorphosis to year 1, M =	0.42	
Larvae duration	19	days

Larvae Remaining 1.9E-06 larvae to metamorphosis

Queenfish

Calculations based on AverageInstantaneous Mortality Rate (M),
per day, found in many marine fish (McGurk 1986)

		Average	
	M =	0.5	/day
Day	Starting # Larvae	End # Larvae	
1	1.000000	0.500000	
2	0.500000	0.250000	
3	0.250000	0.125000	
4	0.125000	0.062500	
5	0.062500	0.031250	
6	0.031250	0.015625	
7	0.015625	0.007813	
8	0.007813	0.003906	
9	0.003906	0.001953	
10	0.001953	0.000977	
11	0.000977	0.000488	
12	0.000488	0.000244	
13	0.000244	0.000122	
14	0.000122	0.000061	
15	0.000061	0.000031	
16	0.000031	0.000015	
17	0.000015	0.000008	
18	0.000008	0.000004	
19	0.000004	0.000002	

Drums and Croakers
They are eight species of croaker or 'drums' (Family Sciaenidae) found off California. These include Queenfish (*Seriphus politus*), white seabass (*Atractoscion nobilis*), black croaker (*Cheilotrema saturnum*), white croaker (*Genyonemus lineatus*), California corbina (*Menticirrhus undulatus*), spotfin croaker (*Roncador stearnsii*), yellowfin croaker (*Umbrina roncador*), and shortfin corvina (*Cynoscion parvipinnis*). Detailed information on Queenfish and white croaker is presented here.

Appendix A
Queenfish (*Seriphus politus*)

Poto California Department of Fish & Game

Range: British Columbia to Gulf of (Baja) California

Life History:
- Size up to 30 cm SL (12 in)
- Age at maturity 1-2 yr
- Life span to 13 yr
- Spawns multiple times March - August peak season in summer; multiple broadcast spawners with pelagic eggs, batch fecundity 60,000 to 2.3 milion eggs

Habitat: Sand and mud bottoms over the open coast from the surf zone to depths of 181 m (594 ft).

Fishery: Recreational and commercial fishery. Commercial catch used for bait.

3.3.7.1 Life History and Ecology
Queenfish are common in southern California, but rare north of Monterey. In southern California, Allen (1982) found queenfish mainly over soft bottoms at 10-70 m (33-230 ft), with highest abundance occurring at the 10 m stratum. Queenfish form dense, somewhat inactive, schools close to shore during the day, but disperse to feed in midwater after sunset (Hobson and Chess 1976). In a study of queenfish off northern San Diego County, DeMartini et al. (1985) found that adults of both sexes made onshore and offshore migrations, but immature fish generally remained within 2.5 km (1.5 miles) of shore at night. Queenfish are active throughout the night, feeding several meters off the seafloor either in small schools or individually. Immature individuals grow at a rate of about 2.5 mm/day, while early adults grow about 1.8 mm/day (0.07 in/day) (Murdoch et al. 1989a). Mortality rate estimates are unavailable for this species. Queenfish is a summer spawner. Spawning is

asynchronous among females, but there are monthly peaks in intensity during the waxing (first quarter) of the moon (DeMartini and Fountain 1981). They also stated that mature queenfish spawn every 7.4 days, on average, regardless of size. Duration of the spawning season is a function of female body size, ranging from three months (April–June) in recruit spawners to six months (March–August) in repeat spawners (>13.5 cm SL [5.3 in]). Based on the spawning frequency and number of months of spawning, these two groups of spawners can produce about 12 and 24 batches of eggs during their respective spawning seasons (DeMartini and Fountain 1981). Demartini (1991) noted the relationship between declines in fecundity, gonadal and somatic condition of queenfish in southern California, and the crash in planktonic production during the 1982-84 El Niño event. Goldberg (1976) found no sexually mature females less than 14.8 cm SL (5.8 in) in Santa Monica Bay. This differs from the findings of DeMartini and Fountain (1981) who found sexually mature females at 10.0–10.5 cm SL (3.9-4.1 in) off San Onofre at slightly greater than age-1. Batch fecundities in queenfish off San Onofre ranged from 5,000 eggs in a 10.5 cm (4.1 in) female to about 90,000 eggs in a 25 cm (9.8 in) fish. The average-sized female (14 cm [5.5 in], 42 g [1.5 ounces]) had a potential batch fecundity of 12,000–13,000 eggs. Parker and DeMartini (1989) estimated the average batch fecundity to be 12,700 for queenfish collected over a five-year period. Based on a female spawning frequency of 7.4 days, a 10.5-cm (4.1 in) female that spawns for three months (April–June) can produce about 60,000 eggs per year, while a 25cm (9.8 in) female that spawns for six months (March through August) can produce nearly 2.3 million eggs per year (DeMartini and Fountain 1981). Tiny young queenfish, less than 1 inch long, appear in late summer and fall; first at depths of 20 to 30 feet, gradually moving shoreward until they enter the surf zonewhen 1 to 3 inches long.

Queenfish feed mainly on crustaceans, including amphipods, copepods, and mysids, along with polychaetes and fishes (Quast 1968, Hobson and Chess 1976, Hobson et al. 1981, Feder et al. 1974). They are a forage species that is probably consumed by a wide variety of larger piscivorous fishes such as halibut, kelp bass, Pacific bonito, Pacific mackerel, and sharks as well as sea lions and cormorants.

3.3.7.2 Population Trends and Fishery

Queenfish was the most abundant sciaenid impinged at five southern California generating stations from 1977 to 1998, and accounted for over 60% of the total fishes impinged (Herbinson et al. 2001). Annual abundance fluctuated from year to year, with notable declines during the strong El Niño events of 1982-83, 1986-87, and 1997-98. However, abundance remained relatively high throughout the over 20-year study period. Queenfish was also one of the three most abundant species of soft-bottom associated fishes in southern California along with white croaker and northern anchovy during a 1982-1984 trawl study (Love et al. 1986). There are both recreational and commercial fisheries for queenfish. Recreational fishers landed an average of 311,000 queenfish per year from 2000 through 2004, with the greatest estimated landings of 942,000 (40 metric tons) occurring in 1992 (RecFIN database).

Appendix B
White croaker (*Genyonemus lineatus*)

Photo Robert Johnson

Range: British Columbia to southern Baja California

Life History:
- Size up to 41 cm SL (16.25 in)
- Age at maturity 1-4 yr
- Life span to 13 yr
- Spawns throughout the year with a peak season in January-March; multiple broadcast spawners with external fertilization; batch fecundity of 15-80 thousand eggs per female

Habitat: Sand and mud bottoms over the open coast from the surf zone to depths of 238 m (781 ft).

Fishery: Sport and commercial fishery.

White croaker (*Genyonemus lineatus*) range from Magdalena Bay, Baja California, north to Vancouver Island, British Columbia (Miller and Lea 1972). They are one of eight species of croakers (Family Sciaenidae) found off California. The other croakers include: white seabass (*Atractoscion nobilis*), black croaker (*Cheilotrema saturnum*), queenfish (*Seriphus politus*), California corbina (*Menticirrhus undulatus*), spotfin croaker (*Roncador stearnsii*), yellowfin croaker (*Umbrina roncador*), and shortfin corvina (*Cynoscion parvipinnis*).

3.3.6.1 Life History and Ecology
The reported depth range of white croaker is from near the surface to depths of 238 m (781 ft) (Love et al. 2005); however, in southern California, Allen (1982) found *Genyonemus* over soft bottoms between 10 and 130 m (33 and 427 ft), and it was collected most frequently at 10 m (33 ft). It is nocturnally active, and is considered a benthic searcher that feeds on a wide variety of benthic invertebrate prey. Adults feed on polychaetes and crustaceans, while juveniles feed during the day in midwater on zooplankton (Allen 1982). White croakers are oviparous broadcast

spawners. They mature between about 130 and 190 mm TL (5.1 and 7.5 in), between their first to fourth year; approximately 50% spawn at age one year (Love 1996). About one-half of males mature by 140 mm TL (5.5 in), and one-half of females by 150 mm TL (5.9 in), and all fish are mature by 190 mm TL (7.5 in) in their third to fourth year (Love et al. 1984). Off Long Beach, white croaker spawn primarily from November through August, with peak spawning from January through March (Love et al. 1984). However, some spawning can occur year-round. Batch fecundities ranged from about 800 eggs in a 155 mm (6.1 in) female to about 37,200 eggs in a 260 mm (10.2 in) female, with spawning taking place as often as every five days (Love et al. 1984). In their first and second years, females spawn for three months for a total of about 18 times per season. Older fish spawn for about four months and about 24 times per season (Love et al. 1984). Some older fish may spawn for seven months. The nearshore waters from Redondo Beach to Laguna Beach are considered an important spawning center for this species (Love et al. 1984). A smaller spawning center occurs off Ventura. Newly hatched white croaker larvae are 1-2 mm SL (0.04-0.08 in) and not well developed (Watson 1982). Larvae are principally located within 4 km (2.5 miles) from shore, and as they develop tend to move shoreward and into the epibenthos (Schlotterbeck and Connally 1982). Murdoch et al. (1989b) estimated a daily larval growth rate of 0.20 mm/day (0.008 in/day). Maximum reported size is 414 mm (16.3 in) (Miller and Lea 1972), with a life span of 12-15 years (Frey 1971, Love et al. 1984). White croakers grow at a fairly constant rate throughout their lives, though females increase in size more rapidly than males from age 1 (Moore 2001).

No mortality estimates are available for any of the life stages of this species.

White croaker are primarily nocturnal benthic feeders, though juveniles may feed in the water column during the day (Allen 1982). Important prey items include polychaetes, amphipods, shrimps, and chaetognaths (Allen 1982). In Outer Los Angeles Harbor, Ware (1979) found that important prey items included polychaetes, benthic crustaceans, free-living nematodes, and zooplankton. Younger individuals feed on holoplankonic crustaceans and polychaete larvae. White croaker may move offshore into deeper water during winter months (Allen and DeMartini 1983); however, this pattern is apparent only south of Redondo Beach (Herbinson et al. 2001).

3.3.6.2 Population Trends and Fishery

Annual relative abundance of white croaker in impingement samples at southern California power plants showed decreases during the strong El Niño events of 1982-83, 1986-87, and 1997-98 as compared with non-El Niño years (Herbinson et al. 2001).

White croaker is an important constituent of the commercial and sport fisheries of California. Prior to 1980, most of the croaker catch was in southern California. However, since 1980, the majority of the commercial catch occurred in central California, and has been attributed to the entrance of Southeast Asian refugees into the fishery (Moore and Wild 2001). Most of the recreational catch is still in southern California from piers, breakwaters, and private boats. Before 1980, statewide white croaker landings averaged 685,000 lb annually, exceeding 1,000,000 lb in several years (Moore and Wild 2001). High landings in 1952 corresponded with the collapse of the Pacific sardine fishery. Since 1991, landings averaged 461,000 lb and steadily declined to an all-time low of 142,500 lb in 1998. State-wide landings by recreational fishermen aboard commercial passenger fishing vessels (CPFVs) averaged about 12,000 fish per year from 1990 to 1998, with most of the catch in southern California. Most white croaker are caught by gillnet and hook-and-line (Moore and Wild 2001). In 2005 there was a reported 0.33 MT landed in San Diego County for a value of $1,022 (PacFIN database).

Appendix C
Speckled sanddab (*Citharichthys stigmaeus*)


Photo: Gerald & Buff Corci

Range: From Montague Island, Alaska, to Bahia Magdaelena, Baja California, Mexico

Life History:
- Size up to 17 cm (6-3/4")
- Age at maturity: females from two years
- Length at maturity: Average 6.4 cm; females 7 – 8 cm
- Life span ranges from 2 to 3 years
- Spawns nearly year-round, Principal spawning from April to September. Eggs are pelagic. Multiple spawns per year with fecundity of 4,200 eggs at lengths of 85-90 mm, 12,000 at 110 mm, and 22,500 eggs at lengths greater than 129 mm.

Habitat:
Speckled sanddabs are soft-bottom fishes found on sand bottoms the inner coastal shelf from northern California to Baja California at depths of 5 to 350 m . The inner shelf is the shallowest part of the benthic coastal zone, with seasonally variable changes in water temperature, salinity, productivity, and turbulence and visibility.

Fishery:
Sanddabs are mostly a sport fishery as their diminutive size limits their commercial harvest.

Bottom dwelling speckled sanddabs are found on soft bottoms where they consume small crustaceans, worms, squid, and fish. Pelagic eggs can be carried long distances by coastal currents. The larval stage may last up to 300 days. Juveniles settle out of the plankton at a length of 2.5 – 3.8 mm.

Appendix D
CIQ Goby complex (*Clevelandia ios, Ilypnus gilberti, Quietula y-cauda*)

Photo: G. Goldsmith

Range: Vancouver Island, British Columbia to Gulf of California
Life History:
· Size up to 57 mm (2.1 in) (arrow goby); 64 mm (2.5 in) (cheekspot goby); 70 mm (2.75 in) (shadow goby)
· Age at maturity from 0.7-1.5 yr
· Life span ranges from <3 yr (arrow goby) to 5 yr (shadow goby)
· Spawns year-round in bays and estuaries; demersal, adhesive eggs with fecundity from 225-1,400 eggs per female with multiple spawning 2-5 per yr
· Juveniles from 14.0-29.0 mm (0.55-1.14 in) are less than 1 yr old
Habitat:Mud and sand substrates of bays and estuaries; commensally in burrows of shrimps and other invertebrates.
Fishery: None

Gobies are small, demersal fishes that are found worldwide in shallow tropical and subtropical environments. The family Gobiidae contains approximately 1,875 species in 212 genera (Nelson 1994, Moser 1996). Twenty-one goby species from 16 genera occur from the northern California border to south of Baja California (Moser 1996). Arrow, cheekspot, and shadow gobies cannot be differentiated with complete confidence at most larval stages (Moser 1996). Therefore, larval gobies that can not be identified to the species level are often grouped into the 'CIQ' goby complex (for *Clevelandia, Ilypnus* and *Quietula*). In addition to the three species comprising the CIQ complex, there are at least five other common species in nearshore waters: blackeye goby (*Rhinogobiops nicholsii*), yellowfin goby (*Acanthogobius flavimanus*), longjaw mudsucker (*Gillichthys mirabilis*), blind goby (*Typhlogobius californiensis*), and bay goby (*Lepidogobius lepidus*).

3.3.2.1 Life History and Ecology

Members of the goby family share a variety of distinguishing characteristics. Their body shape is elongate and can be either somewhat compressed or depressed (Moser 1996). Due to their size and evolved tolerances for a variety of environmental conditions, gobies have been able to colonize habitats that are inaccessible to most other fishes. These habitats include cracks and crevices in reefs, invertebrate burrows, and mudflats. Gobies generally occur in shallow marine habitats, however many members of the family are euryhaline and are able to tolerate very low salinities and even freshwater. Gobies eat a variety of larval, juvenile, and adult crustaceans, mollusks, and insects. Many will also eat small fishes, fish eggs, and fish larvae. Arrow goby *Clevelandia ios* occupy the most northerly range of the three species, occurring from Vancouver Island, British Columbia to Baja California (Eschmeyer et al. 1983). The reported northern range limits of both shadow goby *Quietula y-cauda* and cheekspot goby *Ilypnus gilberti* are in central California with southern ranges that extend well into the subtropical Gulf of California (Robertson and Allen 2002). Their physiological tolerances reflect their geographic distributions with arrow goby being less able to withstand warmer temperatures compared to cheekspot goby. When exposed to temperatures of 32.1°C (89.9°F) for three days in a laboratory experiment, no arrow goby survived, but 95% of cheekspot goby survived (Brothers 1975). Gobies exposed to warm temperatures on mudflats can seek refuge in their burrows where temperatures can be several degrees cooler than surface temperatures. Arrow goby is the most abundant of the three species in bays and estuaries from Tomales Bay to San Diego Bay, including Elkhorn Slough (Cailliet et al. 1977), Anaheim Bay (MacDonald 1975) and Newport Bay (Allen 1982). Arrow gobies inhabit burrows of ghost shrimps *Neotrypnea* spp. and other burrowing invertebrates. In a 5-year study of fishes in San Diego Bay, approximately 75% of the estimated 4.5 million (standing stock) gobies were juveniles (Allen et al. 2002). The reproductive biology of the three species in the CIQ complex is similar. Arrow goby typically mature sooner than the other two species, attaining 50% maturity in the population after approximately 8 months as compared to 16-18 mo for cheekspot and shadow gobies. Mature females for all three of these species are oviparous and produce demersal eggs that are elliptical in shape, typically adhesive, and attached to a nest substratum at one end (Matarese et al. 1989, Moser 1996). Hatched larvae are planktonic and the duration of the planktonic stage was estimated at 60 days for populations in Mission Bay (Brothers 1975). Arrow gobies mature more quickly and spawn a greater number of eggs at a younger age than either the cheekspot or shadow gobies. As with most fishes, fecundity is dependent on age and size of the female. Fecundity of gobies in Mission Bay ranged from 225-750 eggs per batch for arrow gobies, 225 – 1,030 for cheekspot, and 340 – 1,400 for shadow, for a mean of 615 per batch. Mature females for the CIQ complex deposit 2 – 5 batches of eggs per year.

CIQ complex larvae hatch at a size of 2-3 mm (0.08-0.12 in) (Moser 1996). Data from Mission Bay from Brothers (1975) were used to estimate an average growth rate of 0.16 mm/d (0.006 in/d) for the approximately 60 days from hatching to settlement. Brothers (1975) estimated a 60-day larval mortality of 98.3% for arrow goby larvae, 98.6% for cheekspot, and 99.2% for shadow. These values were used to estimate average daily survival at 0.93 for the three species. Once the larvae transform at a size of approximately 10-15 mm SL (0.39-0.59 in), depending on the species (Moser 1996), the juveniles settle into the benthic environment. For the Mission Bay populations mortality following settlement was 99% per year for arrow goby, 66-74% for cheekspot goby, and 62-69% for shadow goby. Few arrow gobies in the Mission Bay study exceeded 3 yr of age based on otolith records, whereas cheekspot and shadow gobies commonly lived for 4 yr (Brothers 1975). There is no fishery for CIQ gobies and therefore no records on adult population trends based on landings data.

Appendix E
Anchovies (Engraulidae)


Photo: T. McHugh

Range: British Columbia to southern Baja California
Life History:
· Size: to 248 mm (9.7 in.)
· Age at maturity: 1-2 yr
· Fecundity: multiple spawning at 6-10 day intervals peaking in late winter and spring, releasing from 2,700 to 16,000 eggs per batch;
· Life span: 4-5 yr (up to 7 yr)
Habitat: Pelagic from surface to depths of 310 m (1,017 ft)
Fishery: Commercial fishery for fish meal reduction, human
consumption, and bait (live and frozen)

Two species of anchovy (Family Engraulidae) are known to inhabit the Edison Canal: northern anchovy (*Engraulis mordax*) and deepbody anchovy (*Anchoa compressa*). Northern anchovy range from Cape San Lucas, Baja California to Queen Charlotte Island, British Columbia, and offshore to 480 km (298 miles) (Hart 1973). They are most common from Magdalena Bay, Baja California to San Francisco Bay and within 157 km (98 miles) of shore (Hart 1973; MBC 1987). Northern anchovy is one of four species of anchovies (Family Engraulidae) that occurs off California (Miller and Lea 1972). Three genetically distinct subpopulations are recognized for northern anchovy; (1) Northern subpopulation, from northern California to British Columbia; (2) Central subpopulation, off southern California and northern Baja California; and (3) Southern subpopulation, off southern Baja California (Emmett et al. 1991).

3.3.4.1 Life History and Ecology

The reported depth range of northern anchovy is from the surface to depths of 310 m (1,017 ft) (Davies and Bradley 1972). Juveniles are generally more common inshore and in estuaries. Eggs are elliptical and occur from the surface to about 50 m (164 ft), while larvae are found from the surface to about 75 m (246 ft) in epipelagic and nearshore waters (Garrison and Miller 1982). Northern anchovy larvae feed on small planktonic organisms such as dinoflagellates, rotifers, and copepods (MBC

1987). Juveniles and adults feed mainly at night on zooplankton, including planktonic crustaceans and fish larvae (Fitch and Lavenberg 1971, Hart 1973, Allen and DeMartini 1983). Northern anchovy spawn throughout the year off southern California, with peak spawning between February and May (Brewer 1978). Most spawning takes place within 100 km (62 miles) of shore (MBC 1987). On average, female anchovies off southern California spawn every 7-10 days during peak spawning periods, approximately 20 times per year (Hunter and Macewicz 1980, MBC 1987). Most spawning occurs at night and is completed by dawn (Hunter and Macewicz 1980). Anchovies are all sexually mature by age two, and the fraction of the population that is sexually mature at one year of age can range from 47 to 100% depending on the water temperature during development (Bergen and Jacobsen 2001). Love (1996) reported that they release 2,700-16,000 eggs per batch, with an annual fecundity of up to 130,000 eggs per year in southern California. Parrish et al. (1986) and Butler et al. (1993) stated that the total annual fecundity for one-year old females was 20,000-30,000 eggs, while a five-year old could release up to 320,000 eggs per year. The northern anchovy egg hatches in two to four days, has a larval phase lasting approximately 70 days, and undergoes transformation into a juvenile at about 35-40 mm (Hart 1973, MBC 1987, Moser 1996). Larvae begin schooling at 11 to 12 mm SL (0.43 to 0.47 in) (Hunter and Coyne 1982). Northern anchovy reach 102 mm (4 in) in their first year, and 119 mm (4.7 in) in their second (Sakagawa and Kimura 1976). Larval survival is strongly influenced by the availability and density of appropriate phytoplankton species (Emmett et al. 1991). Storms and strong upwelling reduce larval food availability, and strong upwelling may transport larvae out of the Southern California Bight (Power 1986). However, strong upwelling may benefit juveniles and adults. Growth in length is most rapid during the first four months, and growth in weight is most rapid during the first year (Hunter and Macewicz 1980; PFMC 1983). They mature at 78 to 140 mm (3.1 to 5.5 in) in length, in their first or second year (Frey 1971, Hunter and Macewicz 1980). Maximum size is about 230 mm (9 in) and 60 g (2.1 ounces) (Fitch and Lavenberg 1971, Eschmeyer et al. 1983). Maximum age is about seven years (Hart 1973), though most live less than four years (Fitch and Lavenberg 1971). Northern anchovy are random planktonic feeders, filtering plankton as they swim (Fitch and Lavenberg 1971). They feed mostly on larval crustaceans, but also on fish eggs and larvae (Fitch and Lavenberg 1971). Numerous fish and marine mammal species feed on northern anchovy. Elegant tern and California brown pelican reproduction is strongly correlated with the annual abundance of this species (Emmett et al. 1991). Temperatures above 25°C (77°F) avoided by juveniles and adults (Brewer 1974).

3.3.4.2 Population Trends and Fishery

Northern anchovy are fished commercially for reduction (e.g., fish meal, oil, and paste) and live or frozen bait. This species is the most important bait fish in southern California, and is also used in Oregon and Washington as bait.

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Section VIII: Cost Benefit Analysis

National Economic Research Associates (NERA) was commissioned by RRI to perform a cost benefit analysis of alternate ways to mitigate adverse environmental impacts for Mandalay and Ormond. RRI provided NERA with operating data on the facilities along with the cost information for two cooling tower options (wet and dry). RRI also asked NERA to evaluate two other mitigation options that could be utilized by RRI in seeking site-specific alternatives through the use of a wholly disproportionate cost showing.[129] These options include 1) the use of one circulating water pump during low load operations and 2) the installation of variable speed pumps that would more closely synchronize the intake water flow with the generator output. Information was also provided on each mitigation alternative's reduction to the intake water flow so that the benefits could be determined.

NERA performed two studies for RRI, a "base case" that represents the 2007-2008 operations of the plant and a "scenario" that represents the high capacity operations that the facilities once had during the 2000-2001 time frame. Factors included on the "cost" side of the analysis include: 1) the cost of the mitigating technology (e.g. the cooling towers or the pumps), 2) any going forward operations and maintenance expense, 3) replacement power cost both during the down time for installation of the technology and for any reduced capacity resulting from the installation of the technology, 4) increased natural gas usage due to the heat rate impacts due to the technology and 5) increased carbon dioxide emissions due to the technology.

[129] RRI has discussed at length why the Draft Policy should be changed to allow reasonable cost-effective site-specific alternatives to BTA and why all facilities should be allowed to seek compliance alternatives through a wholly disproportionate cost showing.

NERA utilized the biological information provided by Mr. McCormick to monetize the "use-benefits" associated with mitigating the impact these facilities have on their intake source waters. The methodology utilized by NERA for monetizing the benefits of 316(b) technologies is consistent with EPA guidelines and requires converting the number of species impinged and entrained into age-1 equivalents to estimate the direct fishery yield impacts. The age-1 equivalent conversion methodology is explained in more detail in NERA's report included in full below. Once the age-1 equivalent is determined, then NERA assigned a value to each species based on their commerical or recreation value. Species that were considered "forage" species, such as Gobies, were given value only for their contribution as food for predator species. NERA assumed that the forage species contributed to increased California Halibut fishery yields.

"Non-use benefits," are those that arise to individuals that do not directly utilize a resource, but value it as an ecological resource. Quantify these benefits are difficult and because of that EPA has suggested that the following be considered: 1) a threat to endangered species, 2) the sustainability of important species of fish, or 3) the maintenance of a community structure in the body of water. Since RRI's two generation facilities do not impact endangered species nor the health of their source waters, no value was given for these "non-use" factors.

As discussed earlier in RRI's comments, the design and current operation of both plants minimizes IM/E impacts. The Ormond Beach facility has an offshore intake equipped with a velocity cap and large mammal exclusion bars. These measures have been recognized by the EPA as mitigating measures. The Mandalay facility is located at the end of a long canal which originates at the Channel Islands Harbor. Thus, neither of

RRI's facilities has a shoreline intake structure, which is EPA's baseline configuration. By virtue of the Mandalay cooling system, water in the increasingly developed canal is periodically circulated, which prevents the canal from becoming anoxic, thereby helping to preserve marine life in the canal. As a conservative assumption in RRI's cost/benefit analysis, NERA assigned no benefit to Mandalay's water circulation of the canal.

The results of the cost benefit analysis show that the installation of cooling towers (dry or wet) would be wholly disproportionate to the benefits received under both scenarios. In the base case scenario, which is considered to be more representative of the units' operations going forward, the combined cost exceeds the benefits for both units by a factor of 533 to 1 for the installation of wet cooling towers. Even if the units were to run considerably more as experienced in 2000-2001, costs still exceed benefits by a factor of 251 to 1. NERA's evaluation of the use of only one pump during low load periods and the installation of variable speed pumps also show that costs exceed benefits a hundred-fold assuming the current low-capacity factor operation of the plants. Even assuming the units run at considerably higher utilization rates, costs still exceed benefits for these two alternatives.

Clearly, an OTC Policy that would require such expenditures without providing alternative compliance options for 45 of the OTC units (other than shutting down) is not reasonable and not in accordance with EPA precedence. Assuming comparable results for the other steam units, these are costs that cannot be reasonably born by the industry. For all the reasons presented by RRI in these comments the Draft Policy must be changed.

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Memo

To: **RRI Energy, Inc.**
Date: September 28, 2009
From: NERA Economic Consulting
Subject: **Preliminary Costs and Benefits of Cooling Water Intake Alternatives for Mandalay and Ormond Beach Generating Stations**

This memo summarizes our preliminary cost-benefit analyses of four technological and operational alternatives to reduce impingement and entrainment at two generating stations owned by RRI Energy, Inc. ("RRI"): Mandalay and Ormond Beach. Both facilities would be subject to the regulations included in the California State Water Resources Control Board's Draft Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling ("Draft Policy"). We first present our summary results using base case assumptions. We then describe the steps to develop these results. We also present summary results using alternative assumptions regarding capacity factors and the discount rate.[1]

A. Summary Results

Table 1 provides a summary of the preliminary cost-benefit results for Mandalay and Ormond Beach. It includes the four technological and operational alternatives that we considered: wet cooling towers, dry cooling towers, single-pump operation when units are operating below a 50 percent capacity factor, and variable speed pumps when units are operating below a 90 percent capacity factor. In our base case we assumed that the facilities would operate at relatively low capacity factors, as in 2007 and 2008.

The costs and benefits are expressed as present values as of January 1, 2009 in millions of 2009 dollars. We assume that the two facilities would implement alternatives to meet the compliance deadlines established in the Draft Policy, i.e., 2020 for both facilities. We calculated present values based on annual costs and benefits from 2020 to 2040. Thus, for example, the preliminary estimate of the present value of costs for wet cooling towers at Mandalay means that $69.8 million would need to be set aside on January 1, 2009 and invested at the discount

[1] This study was supported by RRI, and RRI staff provided valuable information and guidance. Although we are grateful to RRI for its support, this memo does not necessarily reflect the views of RRI, and we alone are responsible for any errors or omissions it may contain. In particular, although this memo analyzes the implications of various provisions in the Draft Policy, it does not in any way imply an endorsement by RRI or NERA of any aspect of the Draft Policy.

rate to equal the stream of costs that are incurred each year from 2020 to 2040. The present value of costs would be much greater if they were calculated as of the compliance date.

The preliminary costs and benefits differ greatly for the various alternatives and scenarios in Table 1. Dry cooling towers are the most expensive alternative, with estimated costs in present value terms of $90 million and $217 million at Mandalay and Ormond Beach, respectively. The least expensive alternative, single-pump operation, would cost $2 million at Mandalay and $11 million at Ormond Beach in present value terms. Wet cooling towers and dry cooling towers both are assumed to reduce cooling water intake by 100 percent (assuming the source of cooling water makeup would be reclaimed water from a municipal wastewater treatment plant). Cooling towers would have benefits of $26,000 at Mandalay and $408,000 at Ormond Beach in present value terms.

Table 1. Preliminary present values of costs, benefits, net costs, and cost/benefit ratios

	Mandalay	Ormond Beach	Total
Wet Cooling Towers			
Costs	$69.822	$161.579	$231.401
Benefits	$0.026	$0.408	$0.434
Net Costs	$69.795	$161.171	$230.967
Cost / Benefit Ratio	2,662	396	533
Dry Cooling Towers			
Costs	$90.457	$216.846	$307.303
Benefits	$0.026	$0.408	$0.434
Net Costs	$90.431	$216.438	$306.869
Cost / Benefit Ratio	3,449	531	708
Single-Pump Operation			
Costs	$2.010	$11.101	$13.110
Benefits	$0.007	$0.106	$0.113
Net Costs	$2.003	$10.994	$12.997
Cost / Benefit Ratio	295	104	116
Variable Speed Pumps			
Costs	$4.976	$28.256	$33.233
Benefits	$0.012	$0.185	$0.197
Net Costs	$4.965	$28.071	$33.036
Cost / Benefit Ratio	425	153	169

Notes: All dollar values are in millions of 2009 dollars.
Present values are as of January 1, 2009 based on a real annual discount rate of 7 percent.
Low capacity factors are assumed.
Source: RRI data and NERA calculations as explained in text

Estimated costs exceed estimated benefits for all alternatives. The estimated net costs (i.e., costs minus benefits) range from $2 million for single-pump operation at Mandalay to $216 million for dry cooling towers at Ormond Beach. The estimated cost/benefit ratios range from 104 for single-pump operation at Ormond Beach to over 3,000 for dry cooling towers at Mandalay.

In estimating these costs and benefits we followed well-established and widely-used guidelines. These include the U.S. Environmental Protection Agency's ("EPA") *Guidelines on Preparing Economic Analyses* (EPA 2000) and the U.S. Office of Management and Budget's ("OMB") guidelines on regulatory analysis (OMB 1992, 2003). These guidelines provide a firm foundation for performing sound and comprehensive cost-benefit assessments. We also made several conservative assumptions to avoid overstating costs or understating benefits. As a result, we believe that the actual net costs and cost/benefit ratios probably would be even larger than our preliminary estimates. Details on our conservative assumptions are given in subsequent sections.

B. Steps in the Development of the Preliminary Cost-Benefit Results

The preliminary cost-benefit results are based on the following three basic steps:

1. define alternative measures and associated reductions in cooling water flow;

2. estimate social costs of the alternative technologies; and

3. estimate social benefits of the alternative technologies.

The following sections summarize these steps and present intermediate results.

C. Alternative Technologies and Reductions in Cooling Water Flow

The cost-benefit analysis considers four technological and operational alternatives: wet cooling towers, dry cooling towers, single-pump operation when units are operating below a 50 percent capacity factor, and variable speed pumps when units are operating below a 90 percent capacity factor. RRI provided costs and operations data for these alternatives. Table 2 shows the assumed reductions in cooling water flow rates associated with each alternative when the facilities operate at relatively low capacity factors, as in 2007 and 2008.

Table 2. Cooling water flow reductions

Alternative	Mandalay	Ormond Beach
Wet Cooling Towers	100%	100%
Dry Cooling Towers	100%	100%
Single-Pump Operation	26%	26%
Variable Speed Pumps	45%	45%

Note: Low capacity factors are assumed.
Source: RRI

D. Costs of Alternatives

This section discusses our analysis of the costs of the alternatives at Mandalay and Ormond Beach. We followed the cost estimation methodology outlined in EPA's *Guidelines for Preparing Economic Analyses*. This methodology provides a firm foundation for performing sound and comprehensive cost assessments. We first present our summary cost results and then describe the steps and data we used to develop these results.

1. Summary of Cost Results

Table 3 summarizes the present value of costs by component for each alternative, expressed as present values using as of January 1, 2009, using a 7 percent discount rate. The categories of costs are capital costs, operating and maintenance costs (O&M) costs, and three types of power costs related to the facilities' electric generation: output impacts (i.e., reductions in net MWh output that would require corresponding amounts of replacement power); heat rate impacts (i.e., increased on-site consumption of natural gas) at operating levels below full load; and air emissions impacts (reflecting the increases in CO_2 emissions due to both replacement power and increased natural gas consumption).

Table 3. Preliminary present values of costs

	Mandalay	Ormond Beach	Total
Wet Cooling Towers			
Capital	$32.401	$64.090	$96.491
O&M	$6.126	$10.170	$16.296
Output Impact	$13.243	$15.242	$28.485
Heat Rate Impact	$10.988	$51.218	$62.206
CO2 emissions	$7.063	$20.859	$27.921
Total	$69.822	$161.579	$231.401
Dry Cooling Towers			
Capital	$56.964	$168.183	$225.146
O&M	$0.503	$1.510	$2.013
Output Impact	$16.668	$11.703	$28.371
Heat Rate Impact	$9.021	$24.370	$33.390
CO2 emissions	$7.302	$11.080	$18.382
Total	$90.457	$216.846	$307.303
Single-Pump Operation			
Capital	$0	$0	$0
O&M	$0	$0	$0
Output Impact	$0.252	$2.655	$2.907
Heat Rate Impact	$1.272	$5.832	$7.104
CO2 emissions	$0.485	$2.614	$3.099
Total	$2.010	$11.101	$13.110
Variable Speed Pumps			
Capital	$2.090	$2.661	$4.751
O&M	$0	$0	$0
Output Impact	$0.646	$6.684	$7.331
Heat Rate Impact	$1.558	$12.915	$14.473
CO2 emissions	$0.682	$5.997	$6.679
Total	$4.976	$28.256	$33.233

Notes: All values are in millions of 2009 dollars.
Present values are as of January 1, 2009 based on a real annual discount rate of 7 percent.
Low capacity factors are assumed.

Source: RRI data and NERA calculations as explained in text

The following sections explain the steps and data we used to develop the cost estimates.

2. Capital and O&M Costs

RRI provided engineering estimates of the capital and O&M costs that each alternative would involve. (Single-pump operation would not involve capital costs, and neither single-pump operation nor variable speed pumps would involve significant O&M costs.) We applied the capital costs in the assumed implementation year for each technology (2020) and assumed that the O&M costs would occur annually thereafter.

3. Impacts on Electric Output

The alternatives would have three types of effects on electric generating activity at the units. First, the alternatives would cause parasitic losses, reducing the units' overall net output (i.e., MWh). Second, the alternatives would increase the units' heat rates, requiring them to consume more fuel per unit of energy generated. Third, air emissions would increase due to both of the previous two factors: the reductions in output at the units would bring about additional emissions from replacement power, and the increase in fuel consumption at the units would directly increase emissions.

For the first of the three factors, RRI provided information on the effects of each alternative on each unit's annual electrical output (MWh), reflecting the units' capacity factors in 2007 and 2008. Table 4 provides this information.

4. Impacts on Heat Rate

RRI also provided information on the effects of the heat rate changes due to the alternatives on facility natural gas consumption, again reflecting 2007-2008 conditions. Table 4 also provides this information.

5. Impacts on Air Emissions

We used the estimates of replacement power needs (MWh) and increased natural gas consumption (MMBTU) to estimate the increase in CO_2 emissions for each alternative. (Other air emissions would also increase, but we do not quantify those increases.) For emissions due to replacement power, we assumed that the replacement generating source would be a natural gas-fired unit with a heat rate of 7,196 btu/KWh, as assumed by the Energy Information Administration ("EIA") for new combined cycle units (EIA 2009c). For natural gas emissions, we used the chemical CO_2 content of natural gas (117 lb/MMBTU; see, e.g., EIA 2009d). Table 4 presents the resulting estimates of CO_2 emissions increases.

Table 4. Preliminary annual effects on electric output, natural gas consumption, and CO_2 emissions

	Mandalay	Ormond	Total
Wet Cooling Towers			
Output Loss (MWh)	36,627	42,156	78,783
Gas Cons. (MMBTU)	278,159	1,296,549	1,574,708
CO2 Emissions (tons)	31,691	93,594	125,285
Dry Cooling Towers			
Output Loss (MWh)	46,099	32,369	78,468
Gas Cons. (MMBTU)	228,348	616,906	845,254
CO2 Emissions (tons)	32,764	49,715	82,480
Single-Pump			
Output Loss (MWh)	698	7,343	8,040
Gas Cons. (MMBTU)	32,206	147,637	179,843
CO2 Emissions (tons)	2,178	11,728	13,905
Variable Speed			
Output Loss (MWh)	1,788	18,487	20,274
Gas Cons. (MMBTU)	39,435	326,929	366,364
CO2 Emissions (tons)	3,060	26,908	29,967

Notes: "Output Loss" refers to the lost electric output at the facility.
"Gas Cons." refers to increased natural gas consumption at the facility.
"CO_2 emissions" refers to the increase in CO_2 emissions from both the replacement power and the increase in facility natural gas consumption.
All results are displayed on an annual basis.

Source: RRI data and NERA calculations as explained in text

6. Electricity, Natural Gas, and Carbon Dioxide Prices

We valued the impacts above on output, natural gas consumption, and CO_2 emissions using forecasts developed by the EIA, as shown in Table 5. The electricity price forecast is the California generation estimate from the Annual Energy Outlook ("AEO") 2009. The natural gas price forecast is the AEO 2009 forecast for natural gas sold to the California electricity sector. The CO_2 price is the allowance price forecast from EIA's recent analysis of the cap-and-trade program included in the Waxman-Markey bill (H.R. 2454) under the 5 percent discount rate scenario.

Table 5. Electricity, natural gas, and carbon dioxide price estimates

	Electricity ($ / MWh)	Natural gas ($ / MMBTU)	CO2 ($ / short ton)
2020	$67.99	$7.42	$31.60
2021	$68.79	$7.65	$33.18
2022	$68.52	$7.54	$34.84
2023	$70.64	$7.09	$36.58
2024	$70.38	$7.07	$38.41
2025	$69.97	$7.17	$40.33
2026	$70.82	$7.35	$42.35
2027	$71.26	$7.62	$44.47
2028	$72.40	$7.95	$46.69
2029	$73.31	$8.18	$49.03
2030	$74.06	$8.44	$51.48
2031	$74.06	$8.44	$51.48
2032	$74.06	$8.44	$51.48
2033	$74.06	$8.44	$51.48
2034	$74.06	$8.44	$51.48
2035	$74.06	$8.44	$51.48
2036	$74.06	$8.44	$51.48
2037	$74.06	$8.44	$51.48
2038	$74.06	$8.44	$51.48
2039	$74.06	$8.44	$51.48
2040	$74.06	$8.44	$51.48

Notes: All values are in 2009 dollars.
EIA projections extend to 2030 and we assume the same real values in subsequent years.
Source: EIA (2009a and 2009b)

E. Benefits of Alternatives

This section provides information on the methods we used to estimate the benefits to society of reduced impingement and entrainment at Mandalay and Ormond Beach. We followed the benefit estimation methodology outlined in EPA's *Guidelines for Preparing Economic Analyses*. This methodology provides a firm foundation for performing sound and comprehensive benefit assessments. We first present our summary benefit results and then describe the steps and data we used to develop these results.

1. Summary of Benefit Results

Table 6 shows our estimated present values of benefits for each alternative as of January 1, 2009 in millions of 2009 dollars, using a real annual discount rate of 7 percent. The categories of benefits are impingement and entrainment.

Table 6. Preliminary present values of benefits

	Mandalay	Ormond Beach	Total
Wet Cooling Towers			
Impingement	$0.013	$0.004	$0.016
Entrainment	$0.014	$0.404	$0.418
Total	$0.026	$0.408	$0.434
Dry Cooling Towers			
Impingement	$0.013	$0.004	$0.016
Entrainment	$0.014	$0.404	$0.418
Total	$0.026	$0.408	$0.434
Single-Pump Operation			
Impingement	$0.003	$0.001	$0.004
Entrainment	$0.004	$0.105	$0.109
Total	$0.007	$0.106	$0.113
Variable Speed Pumps			
Impingement	$0.006	$0.002	$0.007
Entrainment	$0.006	$0.183	$0.189
Total	$0.012	$0.185	$0.197

Note: All values are in millions of 2009 dollars.
Present values are as of January 1, 2009 based on a real annual discount rate of 7 percent.
Low capacity factors are assumed.
Source: NERA calculations as explained in text

2. Overview of Benefit Methodology

EPA's *Guidelines for Preparing Economic Analyses* provide a summary of the benefit categories relevant to an assessment of ecological benefits. The *Guidelines* divide ecological benefits into two major categories: use benefits and non-use benefits.

- *Use benefits* are those associated with actual use of the resource, such as fishing or various water-related activities. Use benefits can be divided into market and non-market use benefits. Market use benefits in the context of fish protection relate to commercial fisheries, and non-market use benefits relate to recreational fisheries. Use benefits also include indirect use benefits, which relate to ecosystem effects that society values indirectly.

- *Non-use benefits*, in contrast, would accrue to individuals who do not use the resource either directly or indirectly, but nonetheless place a value on preventing its impairment.

We developed our benefits estimates in the following steps:

1. estimate the increase in fish populations from reducing impingement and entrainment;

2. estimate the increase in direct fishery yield from reducing impingement and entrainment;

3. estimate the increase in indirect fishery yield from reducing impingement and entrainment;
4. estimate the value of increased fishery yield to commercial and recreational anglers; and
5. assess potential non-use benefits.

We describe how we performed each step of our benefits assessment in the following sections.

3. Fishery Benefits

a. Increase in Fish Populations

We identified species to model for our benefits assessment and then scaled up our benefit estimates to account for other species so that our benefits estimates would be comprehensive. The species we identified to model were those most commonly impinged and entrained at the two facilities and those with available parameters to convert from raw biological information to age-1 adult equivalents and fishery yield impacts.

Table 7 shows the species we modeled, along with their categories as classified in EPA (2006). Game species are defined as species of value to commercial or recreational anglers. Forage species are defined as species of no value to commercial or recreational anglers. As discussed further below, we estimated the increase in direct fishery yields for game species. We did not estimate the increase in direct fishery yields for forage species, because these species are not harvested to any significant degree by commercial or recreational anglers. Forage species provide indirect benefits to society, however, because they are consumed by predator species of value to commercial or recreational anglers. The calculation of indirect benefits accounts for trophic transfer (i.e., the fraction of biomass that is transferred from prey species to predator species). California halibut is the assumed predator species for this analysis. It is not impinged or entrained to any significant degree at Mandalay or Ormond Beach, so it is omitted from the direct impingement and entrainment analysis.

Table 7. Species categories

Species	Category
Shiner surfperch	Forage
Pacific littleneck clam	Game
White surfperch	Game
Topsmelt	Game
Bat eagle ray	Game
Pacific staghorn sculpin	Game
White sea bass	Game
Northern anchovy	Game
Common rock crab	Game
Shovelnose guitarfish	Game
Red rock crab	Game
Vermilion rockfish	Game
Drums and croakers	Game
Flounder	Game
Sanddab	Game
Queenfish	Game
White croaker	Game
Gobies	Forage
Shrimp	Game
California halibut	Predator

Source: EPA (2006)

To estimate the increase in fish populations from reducing impingement and entrainment at Mandalay and Ormond Beach, we began with baseline losses. We used biological data from 2006 that were developed by ENSR and provided to us by RRI.

Table 8 presents the counts and weight of species impinged at the two facilities in 2006. The modeled species accounted for 81 percent of total impingements at Mandalay in terms of weight and 56 percent of total impingement at Ormond Beach. For the purposes of this preliminary cost-benefit analysis, we used the number of individuals impinged as estimates of the number of age-1 adult equivalents impinged.

Table 8. Impingement data

Species	Mandalay		Ormond Beach	
	Count	Weight (lbs)	Count	Weight (lbs)
Shiner surfperch	5,742	117.0	52	1.4
Pacific littleneck clam	27,020	76.4	-	-
White surfperch	93	53.2	47	11.1
Topsmelt	998	48.6	12	5.0
Bat eagle ray	73	45.5	19	23.5
Pacific staghorn	327	40.0	19	1.4
White sea bass	41	33.5	-	-
Northern anchovy	732	20.9	44	1.6
Common rock crab	-	-	537	124.5
Shovelnose guitarfish	-	-	-	-
Red rock crab	-	-	2,035	39.4
Vermilion rockfish	-	-	19	22.1
Drums and croakers	-	-	-	-
Flounder	9	0.1	-	-
Sanddab	-	-	83	2.0
Queenfish	69	0.5	8	0.4
White croaker	-	-	-	-
Gobies	30	1.5	-	-
Shrimp	13	0.5	1,901	16.0
Other species	960	103.0	3,173	194.8
Total	36,107	540.7	7,948	443.1

Notes: "-" denotes no impingement.
Impingement data include heat treatments.
Source: RRI

Table 9 shows the counts of eggs and larvae of species entrained at the two facilities. These species accounted for 92 percent of total egg entrainment and 86 percent of total larval entrainment by count at Mandalay. They accounted for 92 percent of total egg entrainment and 96 percent of total larval entrainment by count at Ormond Beach.

Table 9. Entrainment data

Species	Mandalay		Ormond Beach	
	Eggs	Larvae	Eggs	Larvae
Shiner surfperch	-	-	-	-
Pacific littleneck clam	-	-	-	-
White surfperch	-	-	-	-
Topsmelt	48,178	2,099,575	-	-
Bat eagle ray	-	-	-	-
Pacific staghorn	-	10,520	-	8,372
White sea bass	-	-	-	-
Northern anchovy	-	44,974	19,584,283	3,424,889
Common rock crab	-	-	-	-
Shovelnose guitarfish	-	-	-	-
Red rock crab	-	-	-	-
Vermilion rockfish	-	-	-	-
Drums and croakers	3,877,557	-	110,315,049	-
Flounder	589,066	33,936	4,949,541	-
Sanddab	230,434	3,836	263,458,961	140,887
Queenfish	9,677	-	181,872,653	313,393
White croaker	-	-	6,712,062	325,972
Gobies	-	24,234,764	-	226,591
Shrimp	-	15,743,231	-	74,563,337
Other species	441,960	7,026,651	51,832,038	3,681,454
Total	5,196,872	49,197,487	638,724,587	82,684,894

Notes: "-" denotes no entrainment.
Source: RRI

Table 10 presents our estimates of age-1 adult equivalents for entrained eggs and larvae. This calculation used the baseline entrainment data in Table 9 and conversion factors derived from EPA (2006).

Table 10. Age-1 adult equivalents: Entrainment

	Mandalay		Ormond Beach	
Species	Eggs age-1	Larvae age-1	Eggs age-1	Larvae age-1
Shiner surfperch	-	-	-	-
Pacific littleneck clam	-	-	-	-
White surfperch	-	-	-	-
Topsmelt	15	935	-	-
Bat eagle ray	-	-	-	-
Pacific staghorn	-	186	-	148
White sea bass	-	-	-	-
Northern anchovy	-	4	1,079	278
Common rock crab	-	-	-	-
Shovelnose guitarfish	-	-	-	-
Red rock crab	-	-	-	-
Vermilion rockfish	-	-	-	-
Drums and croakers	1,965	-	55,891	-
Flounder	626	41	5,263	-
Sanddab	245	5	280,122	169
Queenfish	5	-	92,146	210
White croaker	-	-	3,401	219
Gobies	-	63,091	-	590
Shrimp	-	-	-	-

Notes: "-" denotes no entrainment.
Source: NERA calculations based on EPA (2006)

For our benefits assessment we assumed that the proportional reduction in impingement and entrainment from implementing each alternative would be the same as the proportional reduction in cooling water flow. As shown above in Table 2, we assumed that installing wet or dry cooling towers would reduce flow by 100 percent. Installing cooling towers would therefore reduce impingement and entrainment by 100 percent by our assumptions.

Because all baseline losses would be eliminated through the installation of cooling towers by our assumptions, the baseline numbers of age-1 adult equivalents in Table 8 and Table 10 represent the potential increase in fish populations from installing cooling towers. The potential increases in fish populations from the other alternatives (single-pump operation and variable speed pumps) are not shown here. They are calculated as the cooling tower estimates multiplied by the flow reduction percentages for the other alternatives in Table 2.

b. Increase in Direct Fishery Yield

Direct fishery yield is the total weight of commercial and recreational harvests for each species. As noted above, only game species have direct fishery yield benefits, because only game species are harvested by commercial or recreational anglers. Forage species do not have direct fishery yield benefits, because they are not harvested by commercial or recreational anglers.

Table 11 presents the estimated potential increase in direct fishery yield from installing cooling towers and eliminating impingement. These estimates derive from the age-1 adult equivalents for impingement in Table 8 and direct fishery yield conversion factors from EPA (2006). The potential increases in direct fishery yield from the other alternatives (single-pump operation and variable speed pumps) are not shown here. They are calculated as the cooling tower estimates multiplied by the flow reduction percentages for the other alternatives in Table 2.

Table 11. Direct fishery yield benefits (lbs): Impingement

Species	Mandalay	Ormond Beach
Shiner surfperch	x	x
Pacific littleneck clam	76.4 *	-
White surfperch	6.1	3.0
Topsmelt	23.5	0.3
Bat eagle ray	45.5 *	23.5 *
Pacific staghorn	13.0	0.7
White sea bass	10.0	-
Northern anchovy	1.2	0.1
Common rock crab	-	124.5 *
Shovelnose guitarfish	-	-
Red rock crab	-	39.4 *
Vermilion rockfish	-	4.7
Drums and croakers	-	-
Flounder	0.9	-
Sanddab	-	8.0
Queenfish	4.0	0.5
White croaker	-	-
Gobies	x	x
Shrimp	0.5 *	16.0 *

Notes: Estimates apply to cooling towers (other alternatives would be lower by the factors in Table 2).
"-" denotes no impingement.
"x" denotes no direct fishery impact for forage species.
"*" denotes that the impingement direct loss weight from Table 8 is used as an estimate of direct fishery yield benefit because a species-specific conversion factor is unavailable.
Source: NERA calculations based on EPA (2006)

Table 12 presents the estimated potential increase in direct fishery yield from installing cooling towers and eliminating entrainment. These estimates derive from the age-1 adult equivalents for entrainment in Table 10 and direct fishery yield conversion factors from EPA (2006). The potential increases in direct fishery yield from the other alternatives (single-pump operation and variable speed pumps) are not shown here. They are calculated as the cooling tower estimates multiplied by the flow reduction percentages for the other alternatives in Table 2.

Table 12. Direct fishery yield impacts (lbs): Entrainment

	Mandalay		Ormond Beach	
Species	Eggs Yield	Larvae Yield	Eggs Yield	Larvae Yield
Shiner surfperch	x	x	x	x
Pacific littleneck clam	-	-	-	-
White surfperch	-	-	-	-
Topsmelt	1.2	77.9	-	-
Bat eagle ray	-	-	-	-
Pacific staghorn	-	7.4	-	5.9
White sea bass	-	-	-	-
Northern anchovy	-	0.0	1.5	0.4
Common rock crab	-	-	-	-
Shovelnose guitarfish	-	-	-	-
Red rock crab	-	-	-	-
Vermilion rockfish	-	-	-	-
Drums and croakers	115.1	-	3,275.4	-
Flounder	60.2	3.9	505.5	-
Sanddab	23.5	0.4	26,909.9	16.2
Queenfish	0.3	-	5,400.0	12.3
White croaker	-	-	199.3	12.8
Gobies	x	x	x	x
Shrimp	-	-	-	-

Notes: Estimates apply to cooling towers (other alternatives would be lower by the factors in Table 2).
"-" denotes no entrainment.
"x" denotes no direct fishery yield impact for forage species.
Source: NERA calculations based on EPA (2006)

c. Increase in Indirect Fishery Yield

Reducing impingement and entrainment at Mandalay and Ormond Beach would not only provide benefits to the commercial and recreational anglers who harvest the species impinged and entrained at the facilities. It also would provide indirect benefits to the commercial and recreational anglers who harvest predator species that consume the species impinged and entrained at the facilities. We used California halibut, a highly valued fish, as the predator species for this analysis.

Table 13 shows estimated indirect fishery yield benefits from installing cooling towers at the two facilities and eliminating impingement and entrainment. These estimates derive from the age-1 equivalents for impingement in Table 8, the age-1 equivalents for entrainment in Table 10, and indirect fishery yield conversion factors from EPA (2006). EPA (2006) estimates indirect fishery yield benefits only for forage species, but we estimated it for all species (including game species) to be conservative. These estimates also account for other species than those identified in Table 7. The potential increases in indirect fishery yield from the other alternatives (single-pump operation and variable speed pumps) are not shown here. They are calculated as the cooling tower estimates multiplied by the flow reduction percentages for the other alternatives in Table 2.

Table 13. Indirect fishery yield benefits (lbs)

Effect	Mandalay	Ormond Beach
Impingement	540.7	38.1
Entrainment	17.8	108.9
Total	558.5	147.0

Notes: Estimates apply to cooling towers (other alternatives would be lower by the factors in Table 2).
Source: NERA calculations based on EPA (2006)

d. Valuation of Increased Fishery Yield

The increases in fishery yield would accrue to commercial and recreational anglers. We used Southern California data on the weight of commercial and recreational harvests to allocate the increases in fishery yield to commercial and recreational fisheries. Table 14 presents the commercial and recreational shares for each species.

Table 14. Commercial and recreational shares

Species	Commercial	Recreational
Shiner surfperch	x	x
Pacific littleneck clam	100%	0%
White surfperch	0%	100%
Topsmelt	0%	100%
Bat eagle ray	2%	98%
Pacific staghorn	0%	100%
White sea bass	83%	17%
Northern anchovy	100%	0%
Common rock crab	100%	0%
Shovelnose guitarfish	7%	93%
Red rock crab	100%	0%
Vermilion rockfish	3%	97%
Drums and croakers	22%	78%
Flounder	1%	99%
Sanddab	7%	93%
Queenfish	0%	100%
White croaker	56%	44%
Gobies	x	x
Shrimp	100%	0%
California halibut	17%	83%

Notes: "x" denotes that the species is a forage fish without commercial or recreational fishery.
Sources: California Department of Fish and Game (2009) and RecFIN (2009)

Table 15 presents the commercial and recreational values we used to monetize the fishery yield benefits of reducing impingement and entrainment. The commercial values derive from Southern California data on the weight and value of commercial harvests. The recreational values derive from our review of the economic literature on the value recreational anglers would place on increased harvests (Johnston et al. 2006). The commercial and recreational values are measured in dollars per pound of additional harvest. The recreational values have been converted from dollars per fish caught to dollars per pound of harvest using species-specific ratios of fish caught to fish kept (since some recreational anglers release the fish they catch) and average weight per fish.

Table 15. Commercial and recreational values

Species	Commercial Value ($ / lb)	Recreational Value			
		$ / Fish	Caught / Kept	Avg Wt (lbs)	$ / lb
Shiner surfperch	x	x	x	x	x
Pacific littleneck clam	$6.01	-	-	-	-
White surfperch	$2.77	$4.14	1.29	0.35	$15.17
Topsmelt	-	$4.47	2.42	0.34	$31.97
Bat eagle ray	$0.23	$5.00	15.63	7.21	$10.84
Pacific staghorn	-	$0.53	5.55	0.07	$40.62
White sea bass	$2.55	$4.80	5.56	4.81	$5.55
Northern anchovy	$0.05	$0.53	1.61	0.04	$22.10
Common rock crab	$1.29	-	-	-	-
Shovelnose guitarfish	$0.86	$5.00	4.04	4.09	$4.94
Red rock crab	$1.27	-	-	-	-
Vermilion rockfish	$2.13	$5.46	1.11	2.19	$2.77
Drums and croakers	$0.74	$4.14	2.27	0.59	$15.98
Flounder	$2.00	$5.46	1.56	0.99	$8.59
Sanddab	$3.03	$0.53	1.41	0.28	$2.66
Queenfish	$0.74	$0.53	1.48	0.12	$6.83
White croaker	$0.74	$4.14	2.67	0.30	$36.48
Gobies	x	x	x	x	x
Shrimp	$0.64	-	-	-	-
California halibut	$5.68	$10.23	4.90	3.46	$14.38

Notes: All dollar values are in 2009 dollars.
"-" denotes either no commercial fishery or no recreational fishery.
"x" denotes that the species is a forage fish without commercial or recreational fishery.
Sources: California Department of Fish and Game (2009), Johnston et al. (2006), and RecFIN (2009)

To estimate the fishery benefits of installing cooling towers to eliminate impingement and entrainment, we multiplied the increases in direct and indirect fishery yield by the commercial and recreational values. Our estimates appear in Table 16. We accounted for other species than those identified in Table 7 by scaling the benefits values up using the modeled species' percentages of total impingement and entrainment at each facility noted above. Our benefits estimates are thus comprehensive across species. The potential benefits from the other alternatives (single-pump operation and variable speed pumps) are not shown here. They are calculated as the cooling tower estimates multiplied by the flow reduction percentages for the other alternatives in Table 2.

Table 16. Preliminary annual fishery benefits

Effect	Mandalay	Ormond Beach
Direct Fishery Yield		
Impingement		
Modeled Species	$2,380	$593
Other Species	$560	$465
Total	$2,941	$1,058
Entrainment		
Modeled Species	$4,903	$158,857
Other Species	$780	$13,243
Total	$5,684	$172,100
Impingement + Entrainment		
Modeled Species	$7,283	$159,450
Other Species	$1,341	$13,708
Total	$8,624	$173,158
Indirect Fishery Yield		
Impingement		
Modeled Species	$2,030	$276
Other Species	$478	$216
Total	$2,508	$492
Entrainment		
Modeled Species	$199	$1,300
Other Species	$32	$108
Total	$230	$1,409
Impingement + Entrainment		
Modeled Species	$2,229	$1,576
Other Species	$510	$325
Total	$2,738	$1,901
Direct + Indirect Fishery Yield		
Impingement		
Modeled Species	$4,411	$869
Other Species	$1,038	$682
Total	$5,449	$1,550
Entrainment		
Modeled Species	$5,102	$160,157
Other Species	$812	$13,352
Total	$5,914	$173,509
Impingement + Entrainment		
Modeled Species	$9,512	$161,026
Other Species	$1,850	$14,033
Total	$11,363	$175,059

Notes: Estimates apply to cooling towers (other alternatives would be lower by the factors in Table 2).
Source: NERA calculations as explained in text

e. Scaling for Capacity Factors

As noted above, our baseline impingement and entrainment data came from biological sampling in 2006. Cooling water flow in that year was different from 2007-2008, the period for base case capacity factors. We scaled our benefits estimates in Table 16 to account for the different flow levels. Our scaling factors were derived from actual cooling water flow in 2006 and 2007-2008, shown in Table 17.

Table 17. Cooling Water Flow

Flow Scenario	Mandalay	Ormond Beach
2006 (I&E Studies)	27,940	36,200
Average 2007-2008 (Low CF)	12,812	16,762
Ratio	0.46	0.46

Note: All flow values are in million gallons per year.
Source: RRI

We scaled the benefits estimates in Table 16 from 2006 data by the ratios of flow in Table 17 to estimate benefits for our base case capacity factor scenario. The resulting estimates appear in Table 18. The potential benefits from the other alternatives (single-pump operation and variable speed pumps) are not shown here. They were calculated as the cooling tower estimates multiplied by the flow reduction percentages for the other alternatives in Table 2.

Table 18. Baseline Impingement and Entrainment Values by Scenario

Capacity Factor Scenario	Mandalay	Ormond Beach
2006 (I&E Studies)		
Impingement	$5,449	$1,550
Entrainment	$5,914	$173,509
Total	$11,363	$175,059
Average 2007-2008 (Low CF)		
Impingement	$2,499	$718
Entrainment	$2,712	$80,343
Total	$5,210	$81,061

Notes: Estimates apply to cooling towers (other alternatives would be lower by the factors in Table 2).
Source: NERA calculations as explained in text

We used the annual fishery benefits above in Table 18 to calculate the present value of the fishery benefits of reduced impingement and entrainment, as summarized above.

4. Assessment of Non-use Benefits

As noted above, non-use benefits are benefits that are not associated with any direct use by either individuals or society. These benefits arise if individuals value the change in an ecological resource without the prospect of using the resource or enjoying the option to use it in the future. The classic example of a non-use value is that many individuals may be willing to pay to preserve the Grand Canyon from being dammed even though they have never visited it and do not expect to do so in the future. Unfortunately, the only way to estimate non-use values is to use stated preference methods that involve surveying individuals and eliciting their preferences, rather than inferring those values from actual behavior. Such methods are expensive and difficult to apply well.

Recognizing these problems, EPA's Phase II Rule for Section 316(b) cost-benefit analyses provides criteria for determining whether potential non-use benefits are likely to be significant and thus whether monetization should be considered. The Phase II rules recommend that studies consider the "magnitude and character of ecological impacts implied by the results of the impingement and entrainment mortality study and any other relevant information" (69 FR 41648). They suggest considering whether substantial harm is done to one of the following:

1. a threatened or endangered species;
2. the sustainability of populations of important species of fish, shellfish, or wildlife; or
3. the maintenance of community structure and function in a facility's water body or watershed.

Below we discuss the potential significance of non-use benefits by these three criteria in our preliminary assessment.

a. Threatened and Endangered Species

No threatened or endangered species was impinged or entrained at Mandalay or Ormond Beach during the biological sampling in 2006 (Proteus 2009, p. 4). One green turtle, a threatened species, was impinged at Ormond Beach between 1982 and 2006 (Draft Environmental Document, p. 74), which seems too low an incidence to pose a substantial harm to the population. Harbor seals and California sea lions, which are protected under the Marine Mammals Protection Act but are not threatened or endangered, have been impinged at Mandalay and Ormond Beach (Water Board 2009, p. 74). Their impingement numbers, however, are well below the thresholds for population impacts (NMFS 2008). Moreover, both facilities have equipment and procedures in place to return sea turtles and marine mammals unharmed to the ocean when they are impinged alive (MBC 2001a, 2001b). Our preliminary conclusion is that the first EPA criterion for assessing the significance of non-use benefits is not met.

b. Populations of Other Important Species

EPRI (2007) examines the impacts of once-through cooling at California's coastal electric generating facilities on the populations of various fish species. It concludes "there is no evidence from previous Section 316(b) studies or information presented in the Draft California Policy that OTC [once-through cooling] has caused, or is at present causing, significant adverse effects on California coastal fish populations" (EPRI 2007, p. 4-2). Switching to closed-cycle cooling therefore "may result in no measurable benefit to California fish populations" (EPRI 2007, p. 5-2). No biological study on Mandalay or Ormond Beach to our knowledge has found that cooling water intake at these facilities poses substantial harm to the sustainability of populations of important species. Our preliminary conclusion is that the second EPA criterion for assessing the significance of non-use benefits is not met.

c. Maintenance of Community Structure and Function

Proteus (2009, p. 4) reports that nearly all seafloor ecosystems off Southern California are healthy or marginally less healthy, and that habitats around Mandalay and Ormond Beach are almost completely normal. Our preliminary conclusion is that cooling water intake at the two facilities does not pose substantial harm to the maintenance of community structure and function in their local water bodies, and thus that the third EPA criterion for assessing the significance of non-use benefits is not met.

d. Non-use Summary

Our overall preliminary conclusion is that none of the three EPA criteria for assessing the significance of non-use benefits is met, and thus any non-use benefits from reducing impingement and entrainment at Mandalay and Ormond Beach are likely not significant.

5. Effects of Non-Quantified Costs and Benefits

The basic steps in the cost-benefit analysis presented above include identifying the proposed action, determining its effects, valuing the positive effects (benefits) and negative effects (costs) to the extent feasible in dollar terms, and calculating the net costs or net benefits. It is also important to consider the potential effects that are not estimated in monetary terms. Both the U.S. EPA and OMB recommend describing omitted effects qualitatively and evaluating the implications of omitting these factors when presenting the overall results. EPA notes:

> ... following a net benefit calculation, there should be a presentation and evaluation of all benefits and costs that can only be quantified but not valued, as well as all benefits and costs that can be only qualitatively described (EPA 2000, p. 177).

Similarly, OMB states:

> A complete regulatory analysis includes a discussion of non-quantified as well as quantified benefits and costs. A non-quantified outcome is a benefit or cost that has not been quantified or monetized in the analysis. When there are important non-monetary values at stake, you should also identify them in your analysis so policymakers can compare them with the monetary benefits and costs. When your analysis is complete, you should present a summary of the benefit and cost estimates for each alternative, including the qualitative and non-monetized factors affected by the rule, so that readers can evaluate them (OMB 2003, p. 3).

Here we briefly discuss the omitted costs and benefits qualitatively and consider their effects on the overall results. At the end of this section we summarize the conservative assumptions we made to avoid overstating the net costs of fish protection alternatives.

a. Qualitative Assessments of Non-Quantified Costs

Our analysis excludes several types of social costs that may result from implementation of closed-cycle cooling at the affected facilities:

- *PM_{10} emissions due to cooling tower equipment.* The Tetra Tech report states that cooling towers would directly emit particulate matter (PM_{10}). We do not include the social costs of these emissions.

- *Additional impingement and entrainment at other generating stations.* We do not include the social costs of any additional impingement and entrainment at generating stations that would make up for lost output at the affected facilities due to construction outages and energy penalties.

- *Local adverse impacts.* We do not include the social costs of any adverse impacts on local areas, such as noise and aesthetic effects from construction of closed-cycle cooling at the facilities.

Incorporating these non-quantified costs would be expected to cause our overall net cost estimates to increase.

b. Qualitative Assessments of Non-Quantified Benefits

Our benefits assessment considers the relevant benefit categories described both in the EPA *Guidelines* (EPA 2000) and in the Section 316(b) regional benefits analyses for Phase II and Phase III facilities. We quantified and monetized the relevant and significant benefits categories. Several other benefit components included in these two sets of documents are not included in the benefits assessment because, as discussed below, we judged them either to be irrelevant or unlikely to be significant relative to the benefits that are quantified.

- *Non-market direct use benefits.* Our estimates cover all non-market direct use benefits identified by EPA in its Section 316(b) Phase II case studies with the exception of "near-water recreation direct viewing." Such benefits are likely to be zero or near zero because there is no reason to expect that marginal changes in fish abundance would affect the viewing experience on the California coast.

- *Non-market indirect use benefits.* EPA's category of non-market indirect use benefits includes a large number of subcategories. Most of these subcategories are covered implicitly by our inclusion of indirect benefits associated with trophic transfer from forage species and game species to California halibut. The other subcategories appear to be irrelevant in this case. There is no reason to believe that a small change in the fish populations would have any material impact on such categories of potential indirect use benefits as scientific research, TV shows or books on nature, or bird watching.

- *Non-use benefits*. None of the three non-use criteria in the EPA Phase II Rule appears to be met for impingement and entrainment at Mandalay or Ormond Beach, so non-use benefits are likely not significant.

Our preliminary conclusion is that the benefits we have quantified include the major benefit categories relevant to evaluation of the fish protection alternatives at the facilities. The other benefit components discussed above that are not quantified are not likely to be significant. None of these non-quantified benefit categories, individually or collectively, would be large enough to reverse the conclusion that the costs of alternatives at Mandalay and Ormond Beach would exceed their benefits.

6. Conservative Assumptions

Our conservative assumptions to avoid overstating the net costs of fish protection alternatives include the following:

- *Immediate and recurring benefits*. We assumed that the benefits of reduced impingement and entrainment in terms of larger fish populations would occur immediately, when in fact it would take time for the early life stages entrained at the facilities and the juvenile fish impinged to grow up into harvestable fish.

- *Assignment of additional biomass to highly valued species*. We assigned all the additional biomass in the ecosystem from both forage species and game species, after accounting for trophic transfer, to a highly valued predator species: California halibut. In fact, some of the additional biomass would be consumed by other species of less value to fisheries.

- *High recreational fish values*. We used the highest recreational values for each species in the relevant literature we surveyed. We also inflated these values to account for catch-and-release.

- *No additional costs to commercial fisheries*. We estimated the market use benefits as the increase in revenue to commercial fisheries, neglecting the potential increase in their costs. This assumption would tend to overstate the market use benefits.

F. Sensitivity Cases

We evaluated the sensitivity of our preliminary results to two assumptions: capacity factors and discount rate.

1. High Capacity Factor Scenario

We estimated the costs and benefits of the four technological and operational alternatives assuming higher capacity factors. The high capacity factors were based on the period from

2000 to 2001 (during the California energy crisis). Table 19 below presents the assumed capacity factors for both the base (low) and high cases.

Table 19. Capacity Factors

Capacity Factor Scenario	Mandalay	Ormond Beach
Average 2007-2008 (Low)	13.9%	6.7%
Average 2000-2001 (High)	60.5%	38.1%
Ratio	4.35	5.69

Source: RRI

Table 20 provides the summary results for the high capacity factor scenario. Under each alternative and at both facilities, the high capacity factor scenario generates larger benefits, as it implies larger baseline impingement and entrainment and thus larger gains due to the alternatives. The high capacity factor scenario also increases costs for each alternative except for single-pump operation at Mandalay, because the high capacity factor significantly limits the use of a single pump. Overall, the increases in costs exceed the increases in benefits in almost all cases, leading to increased net costs and cost/benefit ratios. In all cases, costs continue to exceed benefits by wide margins.

Table 20. Preliminary present values of costs, benefits, and net costs in the high capacity factor case

	Mandalay	Ormond Beach	Total
Wet Cooling Towers			
Costs	$173.006	$437.132	$610.138
Benefits	$0.115	$2.314	$2.429
Net Costs	$172.891	$434.818	$607.709
Change in Net Costs	$103.096	$273.647	$376.742
Dry Cooling Towers			
Costs	$192.624	$359.837	$552.461
Benefits	$0.115	$2.314	$2.429
Net Costs	$192.510	$357.523	$550.033
Change in Net Costs	$102.078	$141.085	$243.164
Single-Pump Operation			
Costs	$0.430	$17.918	$18.348
Benefits	$0.007	$0.430	$0.437
Net Costs	$0.423	$17.488	$17.911
Change in Net Costs	-$1.580	$6.494	$4.913
Variable Speed Pumps			
Costs	$6.870	$96.804	$103.673
Benefits	$0.022	$0.919	$0.941
Net Costs	$6.848	$95.885	$102.732
Change in Net Costs	$1.883	$67.813	$69.697

Notes: All dollar values are in millions of 2009 dollars.
Present values are as of January 1, 2009 based on a real annual discount rate of 7 percent.
High capacity factors are assumed.
"Change in Net Costs" is relative to the base case (low capacity factors and 7 percent discount rate).
Source: RRI data and NERA calculations as explained in text

2. Low Discount Rate Scenario

Previous results have reflected a 7 percent real discount rate. Table 21 presents results using a 3 percent real discount rate. A lower discount rate increases the present values of all costs and benefits. It causes net costs to be higher because costs increase more in absolute terms than benefits increase.

Table 21. Preliminary present values of costs, benefits, and net costs with 3 percent discount rate

	Mandalay	Ormond Beach	Total
Wet Cooling Towers			
Costs	$130.075	$308.495	$438.570
Benefits	$0.056	$0.871	$0.927
Net Costs	$130.019	$307.624	$437.643
Change in Net Costs	$60.224	$146.452	$206.676
Dry Cooling Towers			
Costs	$159.044	$361.140	$520.185
Benefits	$0.056	$0.871	$0.927
Net Costs	$158.988	$360.269	$519.257
Change in Net Costs	$68.557	$143.831	$212.388
Single-Pump Operation			
Costs	$4.359	$24.057	$28.416
Benefits	$0.015	$0.227	$0.242
Net Costs	$4.345	$23.829	$28.174
Change in Net Costs	$2.342	$12.835	$15.177
Variable Speed Pumps			
Costs	$9.434	$59.505	$68.939
Benefits	$0.025	$0.395	$0.420
Net Costs	$9.409	$59.110	$68.519
Change in Net Costs	$4.444	$31.039	$35.483

Notes: All dollar values are in millions of 2009 dollars.
Present values are as of January 1, 2009 based on a real annual discount rate of 3 percent.
"Change in Net Costs" is relative to the base case (low capacity factors and 7 percent discount rate).
Source: RRI data and NERA calculations as explained in text

3. High Discount Rate Scenario

Table 22 displays our summary results using a 10 percent discount rate. A higher discount rate decreases the present values of costs, benefits, and net costs. Costs remain higher than benefits for all alternatives at both facilities.

Table 22. Preliminary present values of costs, benefits, and net costs (millions) with 10 percent discount rate

	Mandalay	Ormond Beach	Total
Wet Cooling Towers			
Costs	$45.913	$104.522	$150.435
Benefits	$0.016	$0.242	$0.257
Net Costs	$45.897	$104.280	$150.177
Change in Net Costs	-$23.898	-$56.891	-$80.789
Dry Cooling Towers			
Costs	$61.704	$152.635	$214.339
Benefits	$0.016	$0.242	$0.257
Net Costs	$61.688	$152.393	$214.081
Change in Net Costs	-$28.743	-$64.045	-$92.788
Single-Pump Operation			
Costs	$1.178	$6.513	$7.691
Benefits	$0.004	$0.063	$0.067
Net Costs	$1.174	$6.449	$7.624
Change in Net Costs	-$0.829	-$4.545	-$5.373
Variable Speed Pumps			
Costs	$3.235	$16.981	$20.216
Benefits	$0.007	$0.110	$0.117
Net Costs	$3.228	$16.871	$20.099
Change in Net Costs	-$1.736	-$11.200	-$12.936

Notes: All dollar values are in millions of 2009 dollars.
Present values are as of January 1, 2009 based on a real annual discount rate of 10 percent.
"Change in Net Costs" is relative to the base case (low capacity factors and 7 percent discount rate).
Source: RRI data and NERA calculations as explained in text

4. Conclusions Based on Sensitivity Analyses

Our conclusion based on these preliminary results—that the costs of the four fish protection alternatives would exceed their benefits—does not change under alternative assumptions about capacity factors or discount rates.

G. References

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Section IX: RRI's Edits to the Draft Policy

RRI has edited Appendix A of the SED, the "Draft Policy" to conform to its primary recommendations. RRI has suggested some alternatives should the SWRBC decline to adopt the recommendations contained in the Draft Policy mark-up below. Specifically, if the BTA recommendation is rejected in favor of retaining the Draft Policy's Track 1 or Track 2, then RRI requests a specific exclusion for low-capacity factor units. This would be consistent with the EPA Phase II regulations which appropriately recognized that existing units have more difficulty achieving the same BTA threshold established for *new units.* That recommendation is not shown in the Draft Policy mark-up below.

APPENDIX A – STATEWIDE WATER QUALITY CONTROL POLICY ON THE USE OF COASTAL AND ESTUARINE WATERS FOR POWER PLANT COOLING

DRAFT

1. Introduction

   A. Clean Water Act Section 316(b) requires that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. Section 316(b) is implemented through National Pollutant Discharge Elimination System (NPDES) permits, issued pursuant to Clean Water Act Section 402, which authorize the point source discharge of pollutants to navigable waters.

   B. The State Water Resources Control Board (State Water Board) is designated as the state water pollution control agency for all purposes stated in the Clean Water Act.

   C. The State Water Board and Regional Water Quality Control Boards (Regional Water Boards) (collectively Water Boards) are authorized to issue NPDES permits to point source dischargers in California.

   D. Currently, there are no applicable nationwide standards implementing Section 316(b) for *existing power plants**[1] *1*. Consequently, the Water Boards must implement Section 316(b) on a case-by-case basis, using best professional judgment.

   E. The State Water Board is responsible for adopting state policy for water quality control, which may consist of water quality principles, guidelines, and objectives deemed essential for water quality control.

   F. This Policy establishes uniform requirements governing the exercise by the Water Boards of best professional judgment in the implementation of §316(b) for cooling water intake structures at existing coastal and estuarine power plants that must be implemented in NPDES permits.

   G. The intent of this Policy is to ensure that the beneficial uses of the State's coastal and estuarine waters are protected**, consistent with §316(b),** while also ensuring that the electrical power needs essential for the welfare of the citizens of the State are met.

   ~~**H. During the development of this Policy, State Water Board staff has met regularly with representatives from the California Energy Commission (CEC), the California Public Utilities Commission (CPUC), the California Coastal Commission, the California State Lands Commission, the California Air Resources Board, and the California Independent Systems Operator (CAISO) to develop realistic implementation plans and schedules for this Policy that will not cause disruption in the State's electrical power supply. The compliance dates for this Policy were developed considering a report produced by the energy agencies (CEC, CPUC, and CAISO), titled "Implementation of Once-through Cooling Mitigation Through Energy Infrastructure Planning and Procurement Changes", and the**~~

[1] An asterisk indicates that the term is defined in Section 6 of the Policy.

~~accompanying table, titled "Draft Infrastructure Replacement Milestones and Compliance Dates for Existing Power Plants in California Using Once-Through Cooling", included in the Substitute Environmental Document for this Policy. The energy agencies' approach seeks to address the replacement, repowering, or retirement of power plants currently using once-through cooling that (1) maintain reliability of the electric system; (2) meets California's environmental policy goals; and (3) achieves these goals through effective longterm planning for transmission, generation and demand resources.~~

~~I. To prevent disruption in the State's electrical power supply when the Policy is implemented, the State Water Board will convene a Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS), which will include representatives from CEC, CPUC, CAISO, the California Coastal Commission, the California State Lands Commission, and the California Air Resources Board. SACCWIS will assist the Water Boards in reviewing implementation plans and schedules submitted by dischargers pursuant to this Policy.~~

~~J. While the CEC, CPUC and CAISO each have various planning or permitting responsibilities important to this effort, the approach relies upon use of Competitive procurement and forward contracting mechanisms implemented by the CPUC in order to identify low cost solutions for most OTC power plants. The CPUC has authority to order the investor-owned utilities (IOUs) to procure new or repowered fossil generation for system and/or local reliability in the Long-Term Procurement Plan (LTPP) proceeding. In response to the Policy, the CPUC anticipates modifying its LTPP proceeding and procurement processes to require the IOUs to assess replacement infrastructure needs and conduct targeted requests for offers (RFOs) to acquire replacement, repowered or otherwise compliant generation capacity. LTPP proceedings are conducted on a biennial cycle and plans are normally approved in odd-numbered years. The next cycle, the 2010 LTPP, is estimated to result in a decision by 2011. The subsequent cycle, the 2012 LTPP, would in turn result in a decision by 2013. Once authorized to procure by a CPUC LTPP decision, the IOUs need approximately 18 months to issue an RFO, sign contracts, and submit applications to the CPUC for approval. Approval by the CPUC takes approximately 9 months. If the contract involves a facility already licensed through the CEC generation permitting process, then financing and construction can begin. A typical generation permitting timeline is 12 months, but specific issues such as ability to obtain air permits can delay the process. IOUs often give preference to RFO bids with permits already (or nearly) in place. From contract approval, construction usually takes three years, if generation permits are approved, or approximately five years, if generation permits are pending or other barriers present delays. In total, starting from the initiation of an LTPP proceeding (2010 LTPP or 2012 LTPP), seven years are expected to elapse, before replacement infrastructure is operational. Due to the number of plants affected, efforts to replace or repower once-through cooling plants would need to be phased.~~

~~K. Because the Los Angeles region presents a more complex and challenging set of issues, it is anticipated that more time would be needed to study and implement replacement infrastructure solutions. Therefore, total elapsed time is expected to begin in the 2010 and end in 2017 for Greater Bay Area and San Diego regions, which would be addressed beginning in the 2010 LTPP. For the L.A. region, which~~

~~would be addressed beginning in the 2012 LTPP, total elapsed time is expected to begin in 2012 and end in 2020. A transmission solution is expected to have approximately the same timeframe, but could be delayed by greater potential for significant local opposition. In order to assure that repowering or new power plant development in the Los Angeles basin addresses unique permitting challenges, the SACCWIS will assist the State Water Board in evaluating compliance for power plants not under the jurisdiction of the CPUC or CAISO.~~

L. To conserve the State's scarce water resources, the State Water Board encourages the use of recycled water for cooling water in lieu of marine, estuarine or freshwater.

2. Requirements for *Existing Power Plants**

A. **Standard** Compliance **Requirements** ~~**Alternatives**~~

(1) ~~Track 1.~~ **An owner or operator of an *existing power plant** using once through cooling must reduce the annual volume of cooling water circulated at each facility such that the *annual compliance intake flow rate** is 80 percent less than the facility's *annual intake design flow rate**.** ~~**An owner or operator of an *existing power plant** must reduce *intake flow rate** at each unit, at a minimum, to a level commensurate with that which can be attained by a *closed-cycle wet cooling system**. A minimum 93 percent reduction in *intake flow rate** for each unit is required for Track 1 compliance, compared to the facility's design *intake flow rate**. The through-screen intake velocity must not exceed 0.5 feet per second.**~~

~~**(2) Track 2. If an owner or operator of an *existing power plant** demonstrates to the Regional Boards' satisfaction that compliance with Track 1 is not feasible, the owner or operator must reduce impingement mortality and entrainment of all life stages of marine life for the facility, as a whole, to a comparable level to that which would be achieved under Track 1, using operational or structural controls, or both. For the purposes of this policy, a "comparable level" is a level within 10 percent of the reduction in impingement mortality and entrainment achievable under Track 1. Technology-based improvements that are specifically designed to reduce impingement mortality and/or entrainment and were implemented prior to the effective date of the Policy may be counted towards meeting Track 2 requirements.**~~

~~**B. Final Compliance Dates**~~

~~**Existing power plants* shall comply with Section 2.A, above, as soon as possible, but no later than, the dates shown in Table 1, contained in Section 3.E, below.**~~

C. Immediate and Interim Requirements

(1) No later than one year after the effective date of this Policy, the owner or operator of an *existing power plant** with an offshore intake shall install large organism exclusion devices having a distance between exclusion bars of no greater than nine inches, or install other exclusion devices, deemed equivalent by the Regional Water Board.

(2) No later than one year after the effective date of this Policy, the owner or operator of an *existing power plant** unit that is not directly engaging in *power generating activities**, or critical system maintenance, shall cease intake flows, unless the owner or operator demonstrates to the Regional Water Board that a reduced minimum flow is necessary for operations **or to mitigate greater environmental harm**.

(3) The owner or operator of an *existing power plant** must implement measures to mitigate the interim impingement and entrainment impacts resulting from the cooling water intake structure(s), commencing five years after the effective date of this Policy and continuing up to and until the owner or operator achieves final compliance. The owner or operator must include in the implementation plan, described in Section 3.A below, the specific measures that will be undertaken to comply with this requirement. An owner or operator can comply with this requirement by:

(a) Demonstrating to the Regional Water Board's satisfaction that the owner or operator is compensating for the interim impacts through existing mitigation efforts, including any projects that are required by state or federal permits as of the effective date of this Policy; or

(b) Demonstrating to the Regional Water Board's satisfaction that the interim impacts are compensated for by the owner or operator's participation in funding an appropriate mitigation project; or

(c) Developing and implementing a mitigation program for the facility, approved by the Regional Water Board, which will compensate for the interim impingement and entrainment impacts.

D. *Nuclear-Fueled Power Plants**

If the owner or operator of an existing *nuclear-fueled power plant** demonstrates that compliance with the requirements for *existing power plants** in Section 2.A, above, of this Policy would result in a conflict with a safety requirement established by the Nuclear Regulatory Commission (Commission), with appropriate documentation or other substantiation from the Commission, the Water Board will make a site-specific determination of best technology available for minimizing adverse environmental impact that would not result in a conflict with the Commission's safety requirement.

3. Implementation Provisions

A. With the exception of *nuclear-fueled power plants**, which are covered under 3.D, below, within six months of the effective date of this Policy, the owner or operator of an *existing power plant** shall submit an implementation plan **or an intent to file a Wholly Disproportionate Demonstration described in Section 4,** to the State and Regional Water Boards.

(1) The implementation plan shall identify the compliance **plan** ~~**alternative**~~ selected by the owner or operator, describe the general design, construction, or operational measures that will be undertaken to implement the alternative, and propose a realistic schedule for implementing these measures~~**, that is as short as possible**~~. ~~**If the owner or operator chooses to repower the facility to reduce or eliminate reliance upon once-through cooling, or to refit the facility to implement either**~~

~~Track 1 or Track 2 alternatives, the implementation plan shall identify the time period when generating power is infeasible and describe measures taken to coordinate this activity through the appropriate electrical system balancing authority's maintenance scheduling process.~~

~~(2) If the owner or operator selects *closed-cycle wet cooling** as a compliance alternative, the owner or operator shall address in the implementation plan whetherr recycled water of suitable quality is available for use as makeup water.~~

~~B. The SACCWIS shall be impaneled within three months of the effective date of this Policy, by the Executive Director of the State Water Board, to advise the State Water Board on the implementation of this Policy to ensure that the implementation schedule takes into account local area and grid reliability.~~

~~(1) The SACCWIS shall review the owner or operator's proposed implementation schedule and report to the State Water Board with recommendations within one year of the effective date of this Policy.~~

~~(2) The SACCWIS will report to the State Water Board with recommendations on modifications to the implementation schedule every two years starting in 2013.~~

~~(3) The State Water Board will consider the SACCWIS' recommendations and direct staff to make modifications, if appropriate, for the State Water Board's consideration.~~

C. The Regional Water Boards shall reissue or, as appropriate, modify NPDES permits issued to owners or operators of *existing power plants** to ensure that the permits conform to the provisions of this Policy.

~~(1) The permits shall incorporate a final compliance schedule that requires compliance as soon as possible but no later than the deadlines contained in Table 1, contained in Section 3.E, below.~~

~~(2) The Regional Water Boards shall reopen the relevant permits and modify the final compliance schedules, if appropriate, based on modifications to the policy approved by the State Water Board.~~

~~(3) If an owner or operator selects Track 2 as the compliance alternative, the NPDES permit shall include a monitoring program that complies with Section 5 of this Policy.~~

D. Within three months of the effective date of this Policy the Executive Director of the State Water Board, using the authority under section 13267 of the Water Code, shall issue a request that Southern California Edison (SCE) and Pacific Gas & Electric Company (PG&E) conduct special studies for submission to the State Water Board.

(1) The special studies shall investigate alternatives for the *nuclear-fueled power plants** to meet the requirements of this Policy, including the costs for these alternatives.

(2) The special studies shall be conducted by an independent third party, selected by the Executive Director of the State Water Board.

(3) The special studies shall be overseen by a review committee, established by the Executive Director of the State Water Board within three months of the effective date of the Policy, which shall include, at a minimum, representatives of SCE, PG&E, **~~SACCWIS,~~** the environmental community, and staffs of the State Water Board, Central Coast Regional Water Board, and the San Diego Regional Water Board.

(4) The review committee, described above, shall provide a report for public comment detailing the scope of the special studies, including the degree to which existing, completed studies can be relied upon, within one year of the effective date of this Policy.

(5) The review committee shall provide a report for public comment detailing the results of the special studies and shall present the report to the State Water Board within three years of the effective date of this Policy.

(6) The State Water Board shall consider the results of the special studies in evaluating the need to modify this Policy with respect to the *nuclear-fueled power plants**.

E. Table 1. Implementation Schedule

	Milestone	**Responsible Entity/Party**	**Due Date**[2]
1	Issue a request for information to SCE and PG&E to conduct special studies to investigate compliance options for *nuclear-fueled power plants** [Section 3.D]	Executive Director of the State Water Board	[three months after the effective date of the Policy]
2	Establish Review Committee [Section 3.D(3)]	Executive Director of the State Water Board	[three months after the effective date of the Policy]
~~3~~	**~~Establish SACCWIS [Section 3.B]~~**	**~~Executive Director of the State Water Board~~**	**~~[three months after the effective date of the Policy]~~**
4	Submit a proposed implementation plan to the State and Regional Water Boards [Section 3.A]	Owner/operators of existing fossil-fueled power plants	[six months after the effective date of the Policy]

[2] These compliance dates were developed considering information provided by the California Energy Commission, the Public Utilities Commission, CAISO, and the Los Angeles Department of Water and Power (LADWP).

Milestone		Responsible Entity/Party	Due Date[2]
~~5~~	**Provide a report for public comment, detailing the scope of the special studies on compliance options for nuclear-fueled power plants* [Section 3.D(4)**	**Review Committee**	**[one year after the effective date of the Policy]**
~~6~~	~~**Review the owners or operators' proposed implementation schedules and report to the State Water Board with recommendations [Section 3.B(1)]**~~	~~**SACCWIS**~~	~~**[one year after the effective date of the Policy]**~~
~~7~~	~~**Humboldt Bay Power Plant in compliance**~~	~~**Owner/operator**~~	~~**[one year after the effective date of the Policy]**~~
~~8~~	~~**Potrero Power Plant in compliance**~~	~~**Owner/operator**~~	~~**[one year after the effective date of the Policy]**~~
9	Install large organism exclusion devices with a distance between exclusion bars of no greater than nine inches, or equivalent [Section 2.C(1)]	Owner/operators of *existing power plants** with offshore intakes	[one year after the effective date of the Policy]
10	Cease intake flows for units not directly engaging in *power-generating activities** or critical system maintenance, or demonstrate to the Regional Water Board that a reduced minimum flow is necessary for operations **<u>or to prevent greater harm to the environment</u>** [Section 2.C(2)]	Owner/operators of *existing power plants**	[one year after the effective date of the Policy]
11	~~**South Bay Power Plant in compliance**~~	~~**Owner/operator**~~	~~**12/31/2012**~~
12	Report to State Water Board on results of special studies on compliance options for *nuclear-fueled power plants** [Section 3.D(4)].	Review Committee	[three years after the effective date of the Policy]
13	~~**Report to State Water Board on status of implementation of Policy [Section 3.B(2)]**~~	~~**SACCWIS**~~	~~**3/31/2013**~~

Milestone		Responsible Entity/Party	Due Date[2]
14	Commence to implement measures to mitigate the interim impingement and entrainment impacts due to the cooling water intake structure(s) [Section 2.C(3)]	Owners/operations of *existing power plants**	[five years after the effective date of the Policy]
~~**15**~~	~~**Report to State Water Board on status of implementation of Policy [Section 3.B(2)]**~~	~~**SACCWIS**~~	~~**3/31/2015**~~
~~**16**~~	~~**Power plants in compliance: El Segundo, Haynes, and Morro Bay**~~	~~**Owner/operator**~~	~~**12/31/2015**~~
~~**17**~~	~~**Report to State Water Board on status of implementation of Policy [Section 3.B(2)]**~~	~~**SACCWIS**~~	~~**3/31/2017**~~
~~**18**~~	~~**Power plants in CPUC 2010 LTPP Cycle in compliance: Encina, Contra Costa, Pittsburg, Moss Landing [Section 1.J]**~~	~~**Owner/operator**~~	~~**12/31/2017**~~
~~**19**~~	~~**Harbor and Scattergood generating stations in compliance**~~	~~**Owner/operator**~~	~~**12/31/2017**~~
20	~~**Report to State Water Board on status of implementation of Policy [Section 3.B(2)]**~~	~~**SACCWIS**~~	~~**3/31/2019**~~
~~**21**~~	~~**Power plants in CPUC 2012 LTPP Procurement Cycle in compliance: Huntington Beach, Redondo, Alamitos, Mandalay, Ormond Beach [Section 1.J]**~~	~~**Owner/operator**~~	~~**12/31/2020**~~
22	~~**Report to State Water Board on status of implementation of Policy [Section 3.B(2)]**~~	~~**SACCWIS**~~	~~**3/31/2021**~~
23	~~**Diablo Canyon Power Plant in compliance**~~	~~**Owner/operator**~~	~~**12/31/2021**~~
24	~~**San Onofre Nuclear Generating Station in compliance**~~	~~**Owner/operator**~~	~~**12/31/2022**~~

4. Wholly Disproportionate Demonstration.

At the request of an owner or operator of any existing **nuclear or** fossil-fueled power plant ~~**with generating units**~~ **subject to this policy**~~**with a heat rate* of 8500 British Thermal Units (BTUs) per Kilowatthour (KWhr) or less, or any existing *nuclear-fueled power plant****~~, a Regional Water Board may consider the establishment of alternative, less stringent requirements, than **the compliance requirements specified in Section 2.A**~~**. those**~~

~~**specified in Track 1 and Track 2, above**~~, if the Regional Water Board determines that the costs to comply ~~**with Track 1 or Track 2**~~ are wholly disproportionate to the environmental benefits to be gained, provided that:

A. The owner or operator of the *existing power plant** bears the burden of providing detailed, site-specific data to the Regional Water Board supporting the request and demonstrating that alternative requirements are justified. The following information must be included, at a minimum, in the request:

(1) Costs of compliance in terms of **net present value** ~~**dollars per megawatt hour of electrical energy produced**~~ over a~~**n amortization**~~ period of **up to ten** ~~**twenty**~~ years.

(2) Environmental benefits of compliance, including:

(a) The reduction of entrainment provided in terms of **the net present value of** *habitat production foregone**, or some other appropriate method approved by the Regional Water Board;

(b) The reduction of impingement mortality; and

(c) The improvement in receiving water quality due to the reduction of thermal discharge.

(3) An analysis of environmental impacts, including, but not limited to, air emissions resulting from compliance with this Policy**, with the cost/benefit of those emissions quantified to the extent possible.**

(4) Proposed alternative, less stringent requirements.

B. The Regional Water Board may consider any relevant information in making this determination, including the compliance costs associated with **standard compliance requirements**~~**Track 1 and Track 2**~~, as well as any recent technology and infrastructure investments at the power plant.

C. The owner or operator of the *existing power plant** must reduce impingement mortality and entrainment impacts to the extent practicable, as evidenced by the wholly disproportionate demonstration, and as determined by the Regional Water Board. The difference in impacts to marine life resulting from alternative, less stringent requirements shall be fully mitigated.

D. If the owner or operator of a nuclear-fueled power plant requests alternative, less stringent requirements under this section, the affected Regional Water Board shall consider the results of the special studies required under Section 3.D of this Policy.

5. ~~**Track 2**~~ Monitoring Provisions **for alternative mitigation under the wholly disproportionate test**.

A. Impingement Impacts

~~(1)~~ A baseline impingement study shall be performed **to estimate impacts under original design operations**, unless the discharger demonstrates, to the Regional Water Board's satisfaction, that prior studies accurately reflect ~~current~~ impacts **associated with original annual intake design flows**. Baseline impingement shall be measured on-site and shall include sampling for all species impinged. The impingement study shall be designed to accurately characterize the species currently impinged and their seasonal abundance to the satisfaction of the Regional Water Board.

(a) The study period shall be at least 12 consecutive months.

(b) Impingement shall be measured during different seasons when the cooling system is in operation and over 24-hour sampling periods.

(c) When applicable, impingement shall be sampled under differing representative operational conditions (e.g., differing levels of power production, heat treatments, etc.).

(d) The study shall not result in any additional mortality above typical operating conditions.

(2) After the **approved compliance**~~Track 2~~ controls are implemented, to confirm the level of impingement controls, another impingement study, consistent with section 5.A(1)(a) to (d), above, shall be performed and reported to the Regional Water Board.

(3) The need for additional impingement studies shall be evaluated at the end of each permit period. Impingement studies shall be required when changing operational or environmental conditions indicate that new studies are needed, at the discretion of the Regional Water Board.

B. Entrainment Impacts

(1) A baseline entrainment study shall be performed **to estimate impacts under original design oeprations**, unless the discharger demonstrates, to the Regional Water Board's satisfaction, that prior studies accurately reflect ~~current~~ impacts **associated with annual intake design flows**. Baseline sampling shall be performed to determine larval composition and abundance in the source water, representative of water that is being entrained. The source water shall be determined based on oceanographic conditions reasonably expected after **approved compliance**~~Track 2~~ controls are implemented. Baseline entrainment sampling shall provide an unbiased estimate of larvae entrained at the intake **based on original design operation**~~prior to the implementation of Track 2 controls~~.

(a) Entrainment impacts shall be based on sampling for all *ichthyoplankton** and *zooplankton** (*meroplankton**) species. Individuals collected shall be identified to the lowest taxonomical level practicable. When *feasible**, genetic identification through molecular biological techniques may be used to assist in compliance with this requirement. Samples shall be preserved and archived such that genetic identification is possible at a later date.

(b) The study period shall be at least 12 consecutive months, and sampling shall be designed to account for variation in oceanographic conditions and larval abundance and behavior such that abundance estimates are reasonably accurate.

(2) After the **standard compliance**~~Track 2~~ controls are implemented, to confirm the level of entrainment controls, another entrainment study (with a study design to the Regional Water Board's satisfaction) shall be performed and reported to the Regional Water Board.

(3) The need for additional entrainment studies shall be evaluated at the end of each permit period. Entrainment studies shall be required when changing operational or environmental conditions indicate that new studies are needed, at the discretion of the Regional Water Board.

6. Definition of Terms

~~***Blowdown*** **– Refers to the discharge of either boiler water or recirculating cooling water for the purpose of limiting the buildup of concentrations of materials in excess of desirable limits established by best engineering practice.**~~

~~***Closed-Cycle Wet Cooling System*** **– Refers to a cooling water system, using wet cooling, from which there is no discharge of wastewater other than** ***blowdown****.~~

Existing power plant(s) – Refers to any power plant that is not a *new power plant.**

Habitat Production Foregone – Refers to the product of the average *proportional mortality** and the estimated area of the water body that is habitat for the species' source population. *Habitat production foregone** is an estimate of habitat area production that is lost to all entrained species. For example, if the average *proportional mortality** of estuarine species is 17 percent and the area of the source water estuary is 2000 acres, then the *habitat production foregone** is equal to 17 percent of 2000 acres, which is 340 acres.

~~***Heat Rate*** **– Refers to the overall efficiency of a power plant to convert fuel to electricity, stated in terms of British Thermal Units (BTUs) to generate one Kilowatt-hour (KWhr) of electricity. A lower heat rate indicates a more fuel-efficient power generating unit.**~~

Ichthyoplankton – Refers to the planktonic early life stages of fish (i.e., the pelagic eggs and larval forms of fishes).

Annual Compliance Intake Flow Rate **– Refers to the average annual volume of water withdrawn through the intake structure after the approved compliance controls are implemented, expressed as gallons per year.**

Annual Design *Intake Flow Rate* – Refers to the **average annual volume**~~instantaneous rate at which~~ **of** water ~~is~~ withdrawn through the intake structure **based on original design operation assuming 8760 operating hours per year**, expressed as gallons per **year** ~~minute~~.

Meroplankton – Refers to pelagic larvae and eggs of benthic invertebrates.

New power plant – Refers to any plant that is a "new facility", as defined in 40 C.F.R. §125.83 (revised as of July 1, 2007), and that is subject to Subpart I, Part 125 of the Code of Federal Regulations (revised as of July 1, 2007)(referred to as "Phase I regulations").

Nuclear-Fueled Power Plant(s) – Refers to Diablo Canyon Power Plant and/or San Onofre Nuclear Generating Station.

Power-generating Activities – Refers to activities directly related the generation of electrical power, including start-up and shut-down procedures, contractual obligations (hot stand-by), hot bypasses, and other critical maintenance activities regulated by the Nuclear Regulatory Commission. Activities that are not considered directly related to the generation of electricity include (but are not limited to) dilution for in-plant wastes, maintenance of source-and receiving water quality strictly for monitoring purposes, and running pumps strictly to prevent fouling of condensers and other power plant equipment.

Proportional Mortality – the proportion of larvae killed from entrainment to the larvae in the source population.

Zooplankton – those planktonic invertebrates larger than 200 microns (including invertebrates that are planktonic for their entire life cycle, and the pelagic larvae and eggs of benthic invertebrates*).*

Section X: Appendix/Supporting Documents

A. Cooling Tower Alternatives

B. Energy Agency Documents

1. Draft Joint Agency Staff Paper, "Implementation of Once-Through Cooling Mitigation through Energy Infrastructure Planning and Procurement," July 2009

2. Preliminary California ISO Scenario Analysis, "Impacts on Electric System Reliability Restrictions on Once-Through Cooling in California," November 25, 2008

3. "Potential Impacts of the South Coast Air Quality Management District Air Credit Limitations and Once-Through Cooling Mitigation on Southern California's Electricity System"; Energy Agencies' Staff Draft Paper, February 2009

C. Court Decision

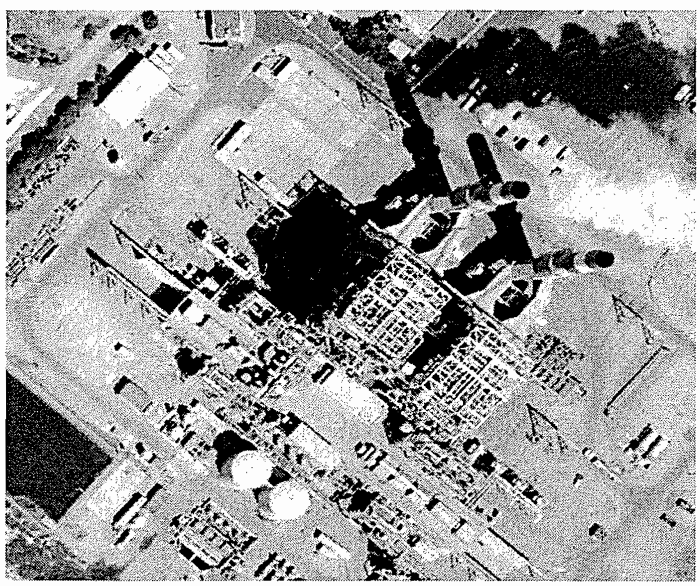
1. *Entergy Corp. vs. Riverkeeper, Inc.* (2009) 129 S.Ct. 1498

D. Supporting Documents

1. Cost vs. Net Revenues
2. Fish Valuation

A. Cooling Tower Alternatives

Reliant Energy



URS
Washington Division

1.0 EXECUTIVE SUMMARY

Reliant Energy has engaged URS-Washington Division (URS-WD) to perform a high level feasibility study for the conversion of their California coastal plants, Mandalay (MGS) and Ormond Beach (OBGS), from ocean once-through cooling to alternative cooling methods.

To address this issue, two alternate cooling methods were considered: (a) fresh water cooling towers (CT) and (b) air cooled condensers (ACC).

For each method, URS-WD developed the following information:

1. Estimated size of CT and ACC
2. Conceptual layout to determine the feasibility of fitting each alternative within the existing property
3. Estimated impact on performance
4. Conceptual (± 30%) cost estimate of the four projects
5. Projected annual cash flow requirements

A significant impact on conceptual design, plant performance and cost estimate of the various alternatives is the CT and ACC size. URS-WD has taken the approach of sizing these components on the basis of historically optimum parameters (specifically, temperature approaches to ambient conditions) and then estimate their impact on plant performance. The elimination of the cold ocean water as the cooling medium results in a significant performance deterioration. No attempt has been made at this level to optimize performance losses versus equipment costs, as the once-through cooling is replaced by the new alternate methods. As a result, the resulting condenser backpressures are different for the different cases (see Tables below).

In the study URS-WD also considered the cost and performance impacts to secondary plant systems that would also be affected by the conversion from the existing cooling scheme. These included Auxiliary Cooling Systems, BFP turbine performance (OBGS), electrical, as well as operations and maintenance considerations. Sources of non-ocean water and discharge of wastes were also considered, based on preliminary data furnished by Reliant.

The information generated by URS-WD will support Reliant in performing a lifetime economic analysis of the facilities as proposed to be modified.

The study results are summarized in the tabulations that follow. Notes are listed at the end of the tabulations.

Summary of Results Cooling Tower Alternative		
	Mandalay **2 Units – 2x215 MWnet**	**Ormond Beach** **Unit 1 – 741 MWnet** **Unit 2 – 775 MWnet**
CT size (each Unit)	50'x325'x42' high(6 cells)	60'x720'x52' high(12 cells)
Performance impact @83°F/47%RH (each Unit) (Note 1)		
Condenser Backpressure (Note 2)	3" HgA	4.4" HgA
Net Output change at max. load	-18.3 MW	U1 -33 MW U2 -34 MW
Net Heat Rate change at max. load	+ 8.9%	U1 +4.4% U2 +4.3%
Net Output change at min. load	-1.05 MW	U1 -3.2 MW U2 -3.2 MW
Net Heat Rate change at min. load	+5.5%	U1 +3.7% U2 +6.8%
Project installed cost- Total Two Units	$ 68.2 M	$ 134.9 M

Summary of Secondary Data Cooling Tower Alternative		
	Mandalay	**Ormond Beach**
Additional Aux. Loads (per Unit)		
At max. Load	2,300 kW	6,800 kW
At min. Load	1,050 kW	3,200 kW
Water Usage (Note 4)		
Makeup (@ max.load)	2,370 gpm	7,210 gpm
Blowdown (@ max load)	470 gpm	1,440 gpm
Source of Make-up water	Assumed Ventura WRF	Assumed Oxnard WTF
Project Duration	23-1/2 Months (490 Working Days)	26-1/2 Months 556 Working Days
Draw Schedule		
Year 2012		$4.7 M (3.5%)
Year 2013	$33.0 M (48.4 %)	$78.3 M (58.0%)
Year 2014	$35.2 M (51.6%)	$52.0 M (38.5%)
Planned outages **See Note below**		
Units 1 & 2 and Common	15 Working Days	15 Working Days
CT Chemicals Consumption @ max. load		
Sodium Hypochlorite (10% solution)	•16.3 lb/hr •2.1 gal/hr	•50.2 lb/hr •6.1 gal/hr

Note:
Required outages for the CT inter-tie are minimal. All work associated with each unit can be performed independently, up to the point of interconnection of the CW pipes to the existing intake, and certain electrical interconnections. The interconnection into the intake can only be performed once for the two units because of its conversion to a CW pump house and blocking off of the ocean water intake feature. At that time a plant outage will be required and no further once-through cooling operation will be possible. No further common outage will be required.

Summary of Results Air Cooled Condenser Alternative		
	Mandalay **2 Units – 2x215 MWn**	**Ormond Beach** **Unit 1 – 741 MWn** **Unit 2 – 775 MWn**
ACC size (each Unit)	130'x290'x100' high (18 Modules)	U1-125'x1020'x135'high(72) U2-260'x510'x155' high (60)
Performance impact @83°F/47%RH (each Unit) (Note 1)		
Condenser Backpressure	3.75" HgA	3.75" HgA
Net Output change at max. load	-24 MW	U1 -28 MW U2 -28 MW
Net Heat Rate change at max. load	+ 12%	U1 +3.7% U2 +3.6%
Net Output change at min. load	-0.6 MW	U1 -3.1 MW U2 -2.45 MW
Net Heat Rate change at min. load	+3.2%	U1 +3.6% U2 +5.2%
Project installed cost- Total two Units	$ 119.9 M	$ 354.0 M

Summary of Secondary Data Air Cooled Condenser Alternative		
	Mandalay	**Ormond Beach**
Additional Aux. Loads (per Unit)		
At max. load	2,600 kW	U1 11,100 kW U2 9,100 kW
At min. load	1,150 kW	U1 3,100 kW U2 2,450 kW
Project Duration	26-1/2 Months (556 Working Days)	29-1/2 Months (615 Working Days)
Draw Schedule		
Year 2012	$3.6 M (3.0%)	$15.2 M (4.3%)
Year 2013	$70.9 M (59.1%)	$174.2 M (49.2%)
Year 2014	$45.4 M (37.9%)	$164.6 M (46.5%)
Planned Outage **See Note below**		
Unit 1 and Common	60 Working Days	60 Working Days
Unit 2	60 Working Days	62 Working Days

Note:

At the completion of the first unit of the ACC conversion, an outage will be required to make the inter-tie of the first unit and all common interconnections. When the second unit work is complete, an outage for only that unit will be required.

Summary of Feasibility Assessment		
	MANDALAY	**ORMOND BEACH**
Cooling Tower	No technical fatal or major flaws identified. Ability of neighboring water reclaim facilities to supply the plant fresh water needs could not be established at the present time. Flow circulation through the intake canal will be discontinued. Installation of new cooling water lines and pump structures presents a high degree of difficulty. CT plume is expected to aggravate existing ambient corrosion problems. Total Plant outages will have to be coordinated with local ISOs.	No technical fatal flaws identified. Ability of neighboring water reclaim facilities to supply the plant fresh water needs could not be established at the present time. Installation of new cooling water lines and pump structures presents a high degree of difficulty. There is a potential that the cooling tower drift plume will impact flight operations at the nearby Point Mugu N.A.S. necessitating the addition of plume abatement. Constructability will be difficult. CT plume is expected to aggravate existing ambient corrosion problems. Total Plant outages will have to be coordinated with local ISOs.

Air Cooled Condenser	No technical fatal or major flaws identified. Flow circulation through the intake canal will be discontinued. Constructability is difficult in view of access restrictions after start of ACC erection. Unit outages will have to be coordinated with local ISOs.	No technical fatal flaws identified. Constructability is difficult particularly for Unit 1 ACC that barely fits on the property. Temporary access on adjacent or nearby property for construction is required. Note that adjacent property is protected wetlands. This would be a highly complex project to implement in view of: (1) The enormous size of the ACC; (2) Potential interferences with existing facilities; (3) Unique ductworks required to connect the gutted condensers with the ACCs; (4) Impact on BFP turbines 5) Impact on maintenance capability for STG Unit outages will have to be coordinated with local ISOs.

B. Energy Agency Documents

1. Draft Joint Agency Staff Paper, "Implementation of Once-Through Cooling Mitigation through Energy Infrastructure Planning and Procurement," July 2009

IMPLEMENTATION OF ONCE-THROUGH COOLING MITIGATION THROUGH ENERGY INFRASTRUCTURE PLANNING AND PROCUREMENT

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DISCLAIMER

This paper was prepared by staff of the California Energy Commission, California Public Utilities Commission, and California Independent System Operator Corporation. It does not necessarily represent the views of these entities or the State of California. The Energy Commission, the State of California, its employees, contractors and subcontractors make no warrant, express or implied, and assume no legal liability for the information in this paper; nor does any party represent that the uses of this information will not infringe upon privately owned rights. This paper has not been approved or disapproved by the California Energy Commission nor has the California Energy Commission passed upon the accuracy or adequacy of the information in this paper. This paper has not been approved or disapproved by the full Commission.

DRAFT JOINT AGENCY STAFF PAPER

July 2009
CEC-200-2009-013-SD

California ISO
Your Link to Power

Arnold Schwarzenegger, *Governor*

Table of Contents

Abstract

This paper outlines a joint proposal by the California Energy Commission, the California Public Utilities Commission, and the California Independent System Operator Corporation to the State Water Resources Control Board intended to assure reliability of the electrical grid while substantially reducing the use of once-through cooling in existing coastal power plants. Rather than focusing on refitting existing power plants to reduce once-through cooling water intake/discharge, the proposed approach develops replacement infrastructure such that existing plants would no longer be needed for local reliability. This replacement infrastructure encompasses refitting existing plants to alternative cooling systems; repowering existing plants; and retiring the current site, possibly requiring transmission system upgrades to rely more upon remote generation. The State Water Resources Control Board has released its proposed once-through cooling mitigation policy, which substantially relies upon this joint agency proposal. The complexities of electrical system planning differ by region within California; thus the proposed approach can be implemented immediately for some regions but requires substantial further analysis of options in other cases. Such analyses would flow into California Public Utilities Commission procurement activities, California Independent System Operator Corporation transmission planning and project approval processes, and Energy Commission power plant licensing proceedings.

Keywords: California Independent System Operator Corporation, California Public Utilities Commission, California Energy Commission, State Water Resources Control Board, South Coast Air Quality Management District, Los Angeles Department of Water and Power, once-through cooling, local capacity requirements, electric system reliability, power plants, priority reserve

Summary

This paper outlines a proposal by the California Energy Commission (Energy Commission) and California Public Utilities Commission (CPUC), in conjunction with the California Independent System Operator Corporation (ISO), to the State Water Resources Control Board (SWRCB) intended to assure electrical grid reliability while substantially reducing once-through cooling (OTC) in existing coastal power plants.[1] The SWRCB's March 2008 preliminary OTC policy report established reliability as a condition for the design and implementation of an OTC mitigation policy but did not propose a mechanism to ensure that reliability is maintained.

In June 2008, the SWRCB formed an Inter-agency Working Group (IWG) to foster communication among seven agencies. The Energy Commission, the CPUC, and the ISO (Energy Agencies[2]) were encouraged to propose alternatives to the fixed compliance schedule proposed by the SWRCB staff in the March 2008 preliminary policy report.

The Energy Agencies propose to adapt existing planning, procurement, and project permitting processes to induce appropriate generation and transmission development to replace existing OTC facilities with some combination of repowered technologies onsite, new generation located in other areas, and/or upgrades to the transmission system. The Energy Agencies understand that the proposal has been accepted by the SWRCB staff and references to it were published as an element of the draft OTC policy on June 30, 2009.

This paper includes in its entirety the proposal made to the SWRCB on May 19 as well as an illustrative schedule for replacing existing OTC facilities. These two items appear as Appendices A and B of this paper. The SWRCB published Appendices A and B of this paper as Appendix C of its Substitute Environmental Document on July 15, 2009.

Background

In June 2006, the SWRCB issued a preliminary proposal concerning reduction of OTC impacts from existing power plants. The preliminary proposal elicited substantial comment expressly cautioning the SWRCB to consider electricity system reliability. In March 2008, the SWRCB issued a second preliminary OTC policy report for electric power plants that established reliability as a condition for the design and implementation of an OTC mitigation policy. The second proposed policy contemplated a phased compliance schedule with time included for the Energy Agencies and the transmission and generation industries to build new infrastructure or identify new resources quickly, thus assuring adequate electrical system reliability. The proposal used historic capacity factors as the basis for establishing fossil power plant compliance dates. Those plants with annual capacity factors below 20 percent were to comply with OTC mitigation by 2015, all other fossil plants by 2018, and the four nuclear units by 2021.

Staff from the Energy Agencies were concerned that the large number of power plants with low capacity factors now largely serving a reliability role could not be replaced realistically

[1] This paper has been reviewed and sanctioned through the management structures of the Energy Commission, the California Public Utilities Commission, and the California Independent System Operator Corporation, but it has not been formally approved or adopted by any of these organizations.

[2] For purposes of expressing collective recommendations, this paper will refer to these three organizations as the Energy Agencies.

by 2015 and that excessive "bunching" of compliance dates would risk creating reliability problems. This stimulated a discussion about the timeline to achieve a systematic schedule for replacement infrastructure.

In December 2008, the Energy Agencies made an initial proposal to the SWRCB that sketched a sequence of analysis, planning decisions, procurement and permitting, and construction of new infrastructure that would establish an operating time horizon for existing OTC power plants to be terminated as new infrastructure became operational. In subsequent meetings and discussions, the SWRCB staff and other members of the IWG communicated broad support for the proposal but also requested refinements that defined milestones and accelerated compliance timelines wherever possible. In particular, the SWRCB staff requested consideration for applying the general approach on a regional rather than statewide basis.[3]

This paper describes the final proposal submitted to the SWRCB on May 19, 2009, focusing on regional analysis and implementation, and leading to a specific schedule when each existing OTC power plant would no longer be required for reliability (updated chart provided on June 22, 2009, and shown in Appendix B).

Energy Agencies' Presumptions About Once-Through Cooling Mitigation

The SWRCB has been engaged in an effort to develop an OTC mitigation policy, and on June 30, 2009 published a draft policy that establishes closed cycle wet cooling towers as the benchmark for compliance. The Energy Agencies agree that a fixed-year outer bound on OTC mitigation compliance can be established, provided it allows for the orderly development of necessary replacement infrastructure and can be amended if conditions, such as permitting and construction delays, indicate that amendment is needed to ensure reliability. The Energy Commission is currently discouraging power plant applications that use once-through ocean water or fresh water-cooling technologies, so the general concept being applied by the SWRCB is already accepted practice for new power plants. This proposal also elaborates upon a general practice adopted by the CPUC in its 2006 Long-Term Procurement Plan (LTPP) rulemaking final decision, directing the investor-owned utilities (IOUs) to acquire new generation that will allow some retirement of existing aging power plants while integrating increasing amounts of renewable energy:

> To support the types of needs we anticipate in a [greenhouse gas]-constrained portfolio and to replace the aging units on which some of this authorization is based, we require [the IOUs] to procure dispatchable ramping resources that can be used to adjust for the morning and evening ramps created by the intermittent types of renewable resources. Preference should be given to procurement that will encourage the retirement of aging plants, particularly inefficient facilities with once-through cooling, by providing, <u>at minimum</u>, qualitative preference to bids involving repowering of these units or bids for

[3] While there are several alternative regional definitions in use among agencies for various specific purposes, for this purpose the local capacity areas used as the basis for resource adequacy requirements are the starting point. The relevant regions that are local capacity areas are San Diego, Los Angeles Basin, Ventura/Big Creek, Greater Bay Area, and Humboldt. To these the Central Coast has been added to encompass all once-through cooling facilities.

new facilities at locations in or near the load pockets in which these units are located.[4]

Preferred Approach

It is possible that the majority of power plant operators will retire their existing facilities rather than invest money to refit the old technologies to meet the proposed SWRCB requirements.[5] To preserve reliability in this case, repowers or new green field facilities enabled by upgraded transmission system capabilities will likely be the mechanism that allows OTC facilities to retire and to reduce or eliminate OTC impacts on the environment.[6] Until then, however, the existing OTC plants must continue to operate in most cases.

As identified in the ISO's *Preliminary Analysis of Reliability Impacts from Restrictions on Once-Through Cooling in California*, retiring plants currently viewed as necessary for local reliability will require replacement in the same area or transmission upgrades to meet local reliability needs must be made in addition to development of replacement generation somewhere else.[7] The preliminary analysis also lays out considerations for power plant development and retirement timing. The study evaluated generation shutdown scenarios of facilities that currently rely on OTC and provided conceptual transmission options, including their order-of-magnitude costs for mitigating the shutdown of these power plant groups. Although clearly preliminary and subject to change, the preliminary analysis reveals the extensive required system upgrades and high cost of relying upon transmission and remote resources that would allow large amounts of capacity to retire without replacement nearby.

The SWRCB's mission is to create policy that guides OTC mitigation for existing power plants. It cannot know whether operators of these existing power plants will choose to comply with the proposed requirements or retire. The more costly the requirements compared to the net revenues available from these facilities under expected market conditions, the more likely retirement becomes.

Meshing the environmental regulator perspective with that of the Energy Agencies is critical to ensure reliability. From the Energy Agency perspective, most capacity cannot be allowed to retire until replacement capacity needed to assure reliability is operational. Analyses of options to satisfy future requirements, planning decisions, procurement processes, permitting, and construction all take time and carry uncertainties that are not easily reduced to a specific date when replacement infrastructure can be certain to be operational. The Energy Agencies would prefer that an OTC mitigation regulation be specified in a conditional manner, that is, an existing OTC plant continues to operate until its replacement

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[4] California Public Utilities Commission, D.07-12-052, http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/76979.htm, p. 106, [111-112, and 115].

[5] With limited exceptions, representatives of the existing OTC plants confirmed this presumption at a May 11, 2009, workshop on OTC mitigation conducted by the Energy Commission as part of the *2009 Integrated Energy Policy Report* proceeding, transcript available at http://www.energy.ca.gov/2009_energypolicy/documents/2009-05-11_workshop/2009-05-11_Transcript.pdf.

[6] Some plant owners may choose to bring the cooling systems into compliance with the proposed SWRCB rules. This alternative is not presented in depth as it is presumed this process will take less time and, therefore, have fewer reliability impacts than building a new or repowered plant.

[7] California Independent System Operator, November 25, 2008, http://www.caiso.com/208b/208b8ac831b00.pdf

is operational. At that point, it can retire, and OTC harm ceases. On the other hand, the SWRCB must establish a policy that creates a deadline to force action by the operator of the plant. Creating a policy with a fixed compliance deadline allows its regional boards to issue necessary permits to the existing plants with knowledge that OTC mitigation will occur on a fixed schedule.

Therefore, the Energy Agencies strongly believe that implementation of an OTC mitigation policy for existing generators has to be integrated with planning and development of the replacement infrastructure necessary to support system reliability. Although estimated dates for new infrastructure being operational have been provided as part of the proposal to the SWRCB, these must be periodically reviewed and updated. Such updates must be reviewed by the SWRCB and, where significant changes have been made, must be used as the basis for changing the permits for existing OTC plants. The Energy Agencies are committed to working together and with the SWRCB to achieve this objective.

Energy Agency Policy Objectives and Constraints

State law and agency policies set forth objectives for the electricity industry that OTC replacement can help achieve. At the same time, reliability and other objectives constrain how quickly OTC replacement can occur. In examining infrastructure development, the approach preferred by the Energy Commission and the CPUC is to pursue system modernization compatible with three key policy objectives, while assuring reliable operation of the system:

- Retire and/or repower all aging power plants unless cost-effectiveness analysis justifies continued use of a specific unit at an aging plant.
- Facilitate sufficient power plant development to meet operational requirements to integrate intermittent renewable resource development, while complying with statewide and air basin air quality attainment plans for criteria pollutants.
- Implement Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006) goals for energy efficiency, demand response, and customer-side of the meter generation technologies to achieve the economy-wide greenhouse gas (GHG) reductions needed for AB 32 and the Governor's Executive Order S-20-06.[8]

Within the broad umbrella of linking OTC mitigation to the development of replacement infrastructure, many alternative plans could be developed. State agency policies emphasize preferred resource types. Taking these considerations into account would probably lead to a different set of proposed fossil power plants than would reliance upon a conventional fossil power plant replacement strategy, most likely a smaller set enabled by more renewable generation and its associated transmission, energy efficiency, distributed generation, and demand response. The following discussion identifies the broad consequences of pursuing these policy initiatives through the analyses of replacement infrastructure options and ultimately making procurement and construction decisions based on the options.

Repowering/Retiring Existing Plants

Since the *2005 IEPR*, the Energy Commission has pursued a policy of repowering or retiring aging power plants. In many instances, the OTC power plants targeted by SWRCB OTC policy were also identified in past *IEPR*s as aging. Closing or repowering such facilities to a

[8] Office of the Governor, October 17, 2006, http://gov.ca.gov/index.php?/executive-order/4484/.

new power plant using a cooling technology other than OTC resolves two concerns simultaneously. Some units may be cost-effectively refitted with alternative cooling systems.

The CPUC has authority to approve cost-based contracts for repowering facilities under Assembly Bill (AB) 1576 (Núñez, Chapter 374, Statutes of 2005), but would need to modify the procurement process to approve designated power plants for long-term contracts with IOUs. In May 2007, the CPUC held public workshops in the 2006 LTPP proceeding (R.06-02-013) to discuss AB 1576 implementation, but to date the CPUC has not used this authority.

Local Air Quality Constraints on New Power Plant Development

The July and November 2008 Superior Court decisions voiding the South Coast Air Quality Management District's (SCAQMD) Priority Reserve Rule and other related rules favorable to repowering of existing generation make unclear how some recently permitted projects, and any current and future power plant proposals in the Energy Commission licensing process, would be constructed in the SCAQMD air shed. SCAQMD's air quality permitting processes affect 7,500 megawatts (MW) of existing fossil capacity in the Los Angeles load capacity area of the ISO and the Los Angeles Department of Water and Power (LADWP) control area. Serious limitations will be placed upon power plant development in the South Coast Basin and nearby areas for some time. New facilities totaling 1,750 MW in capacity have power purchase agreements with Southern California Edison but cannot be licensed because they do not have access to the Priority Reserve. If this issue remains unresolved, these facilities will not be available to reduce the reliability threat from the proposed limitation on the use of OTC. This would significantly increase the challenge of siting new power plants needed to implement the OTC policy and steer solutions to rely more upon transmission system upgrades to tap remotely located generation.

Greenhouse Gas Mitigation

The energy industry's compliance with the detailed regulations that will implement the California Air Resources Board AB 32 *Climate Change Scoping Plan*[9] presumably leads to a lower electricity demand forecast, because additional energy efficiency measures will reduce demand and rooftop photovoltaic and other distributed generation will displace sales of electricity from the bulk power system to end users. A lower demand forecast would require fewer central station generating facilities within load pockets to satisfy reliability criteria. An AB 32 compliance plan presumably also strengthens the role of renewable power generation, which encourages more transmission development, lessening the need for energy from traditional fossil generation but simultaneously increasing the need for dispatchable facilities to provide reliability services. Recognizing these likely consequences from AB 32 implementation could lead to changes in both the mix and capabilities of fossil generation needed in load pockets, whether from repowered OTC plants or from new facilities that are electrically equivalent. Post-AB 32 goals announced by Governor Schwarzenegger in Executive Orders establishing a 33 percent Renewables Portfolio Standard and giving preference to renewable power generation would move even further in this direction than the legislative mandates of AB 32. CPUC staff recently issued a

[9] California Air Resources Board, *Climate Change Scoping Plan,* December 2008, http://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm.

report analyzing the costs, risks, and timing of meeting a 33 percent Renewables Portfolio Standard.[10]

Need for Further Analyses

The Energy Agencies are developing enhanced Local Capacity Requirement (LCR) analyses for the ISO Balancing Authority Area. Some areas lack excess capacity, and every megawatt of peak load increase or power plant retirement means replacement capacity must be developed. Some local capacity areas have surpluses, and some retirement could be tolerated. An Energy Commission staff paper illustrates how constraints on air credits in the Los Angeles Basin would lead to delays in OTC retirement.[11] Based on load and resource assumptions, these analyses will extend current LCR requirements out to 10 years and identify the amount of and various operating characteristics needed to plan for retirement of OTC capacity in some load pockets. The results of these analyses would be the key inputs into an Energy Agency OTC Power Plant Infrastructure Replacement Plan producing specific reliability designations, or dates that specific power plants could retire, as determined by the need for and expected timing of replacement infrastructure development. The plan would identify, for each region, the course of action required to eliminate reliance upon a power plant or unit using OTC. Most importantly, this plan would identify the complete set of infrastructure additions that, once operational, would allow OTC to be eliminated. Recognizing these problems, multiple bills addressing OTC mitigation and restoration of a functioning air quality credit mechanism for new power plants in the South Coast air basin have been proposed in the current session of the legislature.

Applying Existing Planning and Procurement Processes Regionally

To accomplish the retrofitting, repowering, or retirement of more than 30 percent of the power generating capacity in California, significant planning decisions, procurement authorization, and, ultimately, permitting of specific energy infrastructure projects will be necessary.[12] Of the five balancing authorities in California, all of the 19 generation plants with OTC units are encompassed within only two (the ISO and the Los Angeles Department of Water and Power [LADWP]). Of the 16 OTC plants in the ISO control area, 13 are located in transmission-constrained regions. Transmission constraints on the LADWP system also influence both the need for and options among refitting, repowering, and replacing the three OTC plants within the LADWP balancing authority. In sum, the need for OTC plants and options for retrofitting/refitting, repowering, or replacing them are more readily understood at this regional level. Thus, the Energy Agencies propose a process that does not have uniform schedules for all OTC facilities; rather, the regions whose problems are better

[10] California Public Utilities Commission, *33% Renewables Portfolio Standard Implementation Analysis Preliminary Report*, June 2009.
http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm

[11] Energy Commission Draft Staff Paper, *Potential Impacts of the South Coast Air Quality Management District Air Credit Limitations and Once-Through Cooling Mitigation on Southern California's Electricity System*, February 2009, CEC-200-2009-002-SD.

[12] Retrofitting or refitting refers to the installation of a cooling system that complies with the proposed SWRCB policy. Repowering entails replacement of the existing boiler with advanced generation technology – improving thermal efficiency – and installing a compliant cooling technology. Retirement may, and often does, require replacement of the foregone capacity with generation at another location.

understood and where solutions are at hand should be required to reduce OTC harm more quickly than those regions where constraints on implementing solutions are more extensive.

Multi-Step Implementation Proposal

The implementation proposal submitted to the SWRCB encompasses three broad efforts. First, the agencies would conduct a series of studies examining the consequences of retiring individual or clusters of existing OTC power plants under a range of alternative futures and transmission system configurations to identify generation and transmission options for replacing each OTC facility. The Energy Commission would facilitate a review of the LADWP power plants, which are outside of the jurisdiction of the CPUC or the ISO. Second, key analytic results would be reviewed by the agencies to determine a broad strategy that is compatible with broad energy policy preferences. When results are available, they would be entered into the 2010 or 2012 CPUC LTPP proceeding for further analysis by the IOUs and consideration by the CPUC, with the objective of issuing procurement guidance to IOUs to acquire resources, and to the ISO transmission planning process to identify specific transmission projects. Third, necessary power plant additions would be approved by the CPUC and licensed by the Energy Commission, and necessary transmission projects would be licensed by the CPUC. Finally, staff of the Energy Agencies would monitor progress; the Energy Agencies would periodically inform the SWRCB regarding progress and, as appropriate, recommend changes.

Appendix A spells out this effort in greater detail. In particular, the analysis step is likely to have to be repeated periodically as new information is developed or in response to electricity system issues that could not be anticipated in earlier cycles. The SWRCB has acknowledged this possibility and built periodic review into its OTC mitigation policy.

Appendix A also identifies five key uncertainties that had not yet been resolved by the time this proposal had to be submitted to the SWRCB. These are:

- Availability of air pollution credits in SCAQMD for new power plants displacing OTC power plants, or repowers of existing OTC plants/units to eliminate OTC cooling technologies.
- Sequencing of bidding into utility request for offers (RFOs) versus permitting of a facility.
- The degree of reliance upon conventional generating facilities versus preferred technologies.
- Analyses of nuclear generating units at San Onofre and Diablo Canyon.
- Development of a comprehensive plan and preferential treatment of elements of the plan in licensing proceedings compared to proposed facilities not included within the plan.

Expected OTC Replacement Schedule

Appendix B provides a nominal schedule for creating replacement infrastructure for all OTC power plants. The table and its footnotes identify that construction of replacement infrastructure for some OTC plants is already underway or even operational. The replacement infrastructure for other power plants requires substantial analysis of the options, decisions among the Energy Agencies, and then procurement, permitting, and construction lead times. The complexities of these analyses differ from one region to another, with the Los Angeles Basin expected to be the most problematic given severe limitations on the air credits needed for new generation development. For this reason, the schedule of dates for replacement infrastructure typically is further into the future for the existing OTC plants located in the Los Angeles Basin.

Next Steps

This paper presents the background necessary to understand the two components of the proposal by the Energy Agencies submitted to the SWRCB on May 19, 2009, (with minor updates to the OTC chart made on June 22, 2009). The two components are reproduced as Appendices A and B. The Energy Agencies are now compiling information about the evaluations that are relevant to the OTC power plants in the various regions, and preparing a workplan for those further analyses that are needed. The analytic work will be initiated in the third quarter of 2009 and continued through 2010 with results for various regions released as completed.

The Energy Commission and the CPUC will conduct a joint workshop as part of the Energy Commission's *2009 Integrated Energy Policy Report* proceeding and the CPUC's 2008 LTPP rulemaking on July 28, 2009, to solicit input from the generator community, environmental groups, agencies with environmental responsibilities, and the public. Technical staff of the three Energy Agencies will be available to answer questions about this proposal.

APPENDIX A: Specific Proposal for Planning and Procurement of Electricity Infrastructure

This narrative description of the Energy Agency proposal was submitted to the SWRCB on May 19, 2009.

Background

In March 2008, the State Water Resources Control Board (SWRCB) issued a preliminary once-through cooling (OTC) policy report for electric power plants establishing reliability as a condition for the design and implementation of an OTC mitigation policy. The proposed policy contemplates a phased compliance schedule that would allow sufficient time for the energy agencies and the transmission and generation industries to build new infrastructure or identify new resources in a timely manner, thus assuring adequate electrical system reliability. The following outline identifies the steps that the California Public Utilities Commission (CPUC), California Energy Commission, and California Independent System Operator Corporation (The California ISO) intend to undertake to support the SWRCB efforts. This proposal seeks to address the replacement or repowering of OTC power plants through an approach that (1) maintains reliability of the electric system; (2) meets California's environmental policy goals; and (3) achieves these goals through effective long-term planning for transmission, generation and demand resources. The proposal relies upon use of competitive procurement and forward contracting mechanisms to identify low cost solutions.

The SWRCB recognized that its implementation process could create transitional problems, so it created an Inter-agency Working Group (IWG) to review these implementation challenges and other aspects of the proposed policy.

In a December 15, 2008 paper, the Energy Commission and the CPUC in conjunction with the California ISO proposed an alternative approach to the fixed time schedule to reduce OTC in existing coastal power plants, while assuring reliability of the electrical grid.[13] That paper broadly sketched out changes to planning, procurement and project permitting processes to encourage repowering or new infrastructure so that retirement of OTC facilities can occur without threatening reliability. In subsequent meetings and discussions, the SWRCB staff and other members of the IWG communicated broad support and requested refinements that defined milestones and accelerated compliance timelines wherever possible. In particular, the SWRCB staff requested consideration of applying the general approach on a regional, rather than statewide basis.[14] This paper modifies the original proposal, focusing on regional analysis and implementation.

Proposal for Planning and Procurement of Electricity Infrastructure

To accomplish the retrofitting, repowering or retirement of more than 30 percent of the power generating capacity in California, significant planning decisions, procurement authorization, and ultimately permitting of specific energy infrastructure projects will be necessary.[15] Of the five balancing authorities in California, only two (the California ISO and the Los Angeles Department of Water and Power (LADWP)) are needed to encompass all of the 19 generation plants with OTC units. Of the 16 OTC plants in the California ISO, 13 are located in transmission constrained regions. Transmission constraints on the LADWP system also influence both the need for and options among refitting, repowering and replacing the three OTC plants within the LADWP balancing authority. In sum, the need for OTC plants and options for repowering or replacing them are more readily understood at this regional level. Thus, the Energy Agencies propose a process that does not have uniform schedules for all OTC facilities; rather, the regions whose problems are better understood and where solutions are at hand should be required to reduce OTC harm more quickly than those regions where constraints on implementing solutions are more extensive.

Listed below are the key steps of this approach that will result in an OTC Power Plant Replacement Infrastructure Plan (Plan) and the permitting and procurement steps that will implement it.

1. Establish regional basis for analyses and identify existing transmission and system operations studies relevant to establishing constraints on the retirement of specific OTC plants/units:

[13] For purposes of expressing collective recommendations, this paper will refer to these three organizations as the Energy Agencies.

[14] While there are several alternative regional definitions in use among agencies for various specific purposes, for this purpose the local capacity areas used as the basis for resource adequacy requirements are the starting point. The relevant regions that are local capacity areas are San Diego, Los Angeles Basin, Ventura/Big Creek, Greater Bay Area, and Humboldt. To these the Central Coast has been added to encompass all once-through cooling facilities.

[15] Retrofitting refers to the installation of a cooling system that complies with the proposed SWRCB policy. Repowering entails replacement of the existing boiler with advanced generation technology – improving thermal efficiency – and installing a compliant cooling technology. Retirement may, and often does, require replacement of the foregone capacity with generation at another location.

a. Review definition of the regions to understand local reliability issues and assign OTC facilities to each region.

b. Review existing Local Capacity Requirement (LCR) studies of those regions containing OTC plants. Review specific new generation and transmission project proposals and licensing decisions by regulatory agencies for impacts on future LCR values.

c. Review other regional and system studies to determine the operating characteristics of the current generating fleet, how the amount of needed characteristics could change going forward under preferred resource (energy efficiency, renewable, and demand response) and transmission to support those resources, and the implications of OTC plant/unit retirements for the necessary characteristics of replacement facilities.[16]

d. Compile results of Steps 1.a through 1.c and identify, to the extent possible, a realistic development schedule for needed replacement infrastructure to establish the dates by which existing OTC power plants/units will no longer draw in and discharge ocean water above levels allowed by the SWRCB policy. For those plants/units requiring further analyses, Step 2 is needed.

2. Complete an enhanced Local Capacity Requirement evaluation, or other relevant assessment, for each region that contains OTC power plants, and update amounts of necessary operating characteristics as needed.[17]

   a. The Energy Commission and the CPUC will develop scenarios of annual load projections for each region, any projected generation or resource additions or non-OTC retirements for each region, and any transmission project upgrades or additions+ in each year from 2012 up to and including 2019 reflecting alternative ways in which preferred resource development policies could be implemented. The Energy Commission and the CPUC, in consultation with the California ISO, will review these scenario results and select the assumptions to be used for the following enhanced LCR evaluation.

   b. The California ISO will prepare an enhanced LCR evaluation for each year 2012 to 2019 based on those projections and available The California ISO –performed transmission studies.[18] These enhanced LCR evaluations will identify expected

[16] As an illustration, the California Independent System Operator study of the implications of 20 percent penetration of renewable generation, November 2007.

[17] Enhanced implies conducting an local capacity requirement-style analysis of capacity needs, but doing so 10 years forward and identifying the impacts of specific once-through cooling retirements or transmission developments on the area's local capacity requirement projections.

[18] Three of the facilities that use once-through cooling are operated by the Los Angeles Department of Water and Power. As a publicly-owned utility, Los Angeles Department of Water and Power makes investment decisions in the interests of its customers and does not come under the jurisdiction of the California Public Utilities Commission. As a separate control area, it is responsible for its own reliability studies and is not part of the California Independent System Operator's balancing authority area. The Energy Agencies believe the elimination of once-through cooling at these facilities will require the development of new infrastructure. Therefore, it is possible that the Los Angeles Department of Water and Power will need to compete with generator owners to secure Emission Reduction Credits (ERCs) in the air shed under SCAQMD jurisdiction. The Energy Commission hopes to facilitate the Los Angeles Department of Water and Power's cooperation in the Plan; however, absent such cooperation the Energy Agencies will proceed to develop the Plan as it pertains

generation capacity needed within the LCR Areas and OTC regions for each year for given transmission system configurations.

c. The Energy Agencies will then compare projected LCR needs with total expected generation less the capacity represented by OTC power plants/units in each LCR Area to identify the necessary capacity to replace OTC power plants/units in each region. The sequence for removing OTC plants/units through time will be based on effectiveness in mitigating various system contingencies, plant/unit-specific characteristics, and other operational needs in maintaining reliability.

d. The California ISO, in consultation with the CPUC and Energy Commission, will identify the specific characteristics of that capacity (e.g. ramping ability, minimum load constraints, regulation requirements, etc.) needed to meet systems needs once the OTC plants are retired.

e. The Energy Agencies will jointly identify what additional system capacity is needed in connection with replacing each OTC power plant/unit. While replacement capacity needed in an LCR area may be less than that provided by OTC plants/units, system-wide capacity needs may require additional power plant development elsewhere in the California ISO balancing authority area.

f. The California ISO envisions performing enhanced LCR studies each year that can support efforts to refine capacity requirements set forth in the Plan. Any updates to the Plan would occur in consultation and agreement by the Energy Agencies and would be made available to the IWG (or the Statewide Task Force) which would be formalized upon approval of the OTC Policy and the SWRCB. Any Plan updates may also reflect transmission and/or generation infrastructure constructed and completed).

g. For those OTC power plants that are not located in LCR Areas, the Plan would consider the need for capacity located within the California ISO balancing authority area (or LADWP balancing authority area) to serve system need.

3. The Energy Agencies will review the results of Steps 1 and 2 and, for each region, describe the course of action required to eliminate reliance upon a power plant/unit using OTC as a cooling technology. A specific schedule for each existing OTC plant/unit would be developed that identifies the latest date it would operate using OTC technology. After such date, the plant/unit will lose its reliability designation. New generating capacity would satisfy the characteristics identified in Step 2d. Collectively this set of decisions about OTC elimination and replacement infrastructure would be referred to as the "Plan." This initial version of the Plan would be updated periodically as a result of actual experience with generation and transmission project development timelines, or other material changes in assumptions affecting infrastructure needs.

4. The SWRCB and its regional boards would use the Plan as the basis for establishing an OTC mitigation policy and for issuing NPDES permits for each plant/unit based on its reliability designation. The projected date of operation of the specific replacement

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to once-through cooling power plants within the California Independent System Operator's balancing authority area.

infrastructure needed to assure reliable operation of the grid without the facility using OTC technology should be the basis for the expiration date for that plant/unit's permit.

5. The Energy Commission would review the Plan to determine how its power plant licensing process may be affected, and to facilitate air quality management district (AQMD) review by:

    a. Providing an estimate to each local AQMD of the magnitude of air quality credits likely to be required for licensing the new or repowered generating facilities included within the Plan.

    b. Obtaining AQMD concurrence that the volumes of credits used in the studies were credible, or working with an AQMD to devise valid sources of credits and estimates of their costs.

    c. Communicating any significant change in assumptions about air credit availability and costs back to other entities involved in studies and procurement activities.

6. The CPUC would authorize IOU procurement mechanisms to require the IOUs to conduct a large set of targeted RFOs following the 2010 and subsequent long-term procurement proceedings. These targeted RFOs would focus on acquiring needed replacement capacity in appropriate locations with operational characteristics that would allow existing OTC plants/units to retrofit, repower or retire consistent with the Plan.

7. The California ISO will consider SWRCB directives and schedules limiting or canceling water permits required to operate OTC plant/units in the 2011 and subsequent annual Transmission Planning Process. The California ISO will conduct an analysis as part of its Transmission Planning Process reflecting projected OTC plant/unit retirements as a result of SWRCB permitting directives and schedules, which shall be incorporated into the California ISO's annual Transmission Plan that serves as a basis for further economic or reliability based transmission upgrades or additions.

8. Once each targeted RFO was complete, generator retrofits, repowers or new generating facility development assumptions would be updated in the Plan, to the extent the results from the RFOs differ from the previous edition of the Plan. Any updates to the Plan would result in the SWRCB, or its regional boards, modifying permits for various power plants/units depending upon their role in carrying out the Plan.[19]

9. If there are changes (e.g. delays in project development or major modifications to forecast assumptions) in the infrastructure development assumptions (e.g. transmission upgrades or additions are not on schedule, or new generating capacity is not operational) upon which the Plan is based, the Energy Agencies will perform appropriate analysis and inform the SWRCB, or its regional boards, of the new time period that a specific OTC plant/unit is required for system reliability.

[19] For some once-through cooling power plants, this would mean issuing a time-limited permit allowing the plant to operate without change until a specific date at which time it would be shut down and no permit extensions allowed. For other power plants with longer timelines for continued operations, some modification of water intake structures and water usage patterns would be required, but still the plant would not be required to undergo major change because it is scheduled to be retired by a specific date. For still other plants, shifts to closed cycle cooling would be required consistent with long-term continued usage of the power plant.

10. The Energy Agencies will periodically update the Plan to reflect changing system conditions and transmission and generation developments to ensure that OTC mitigation is timely while preserving system reliability. It is possible that transmission upgrades and additions associated with California's Renewable Energy Transmission Initiative may address some system reliability concerns raised by OTC power plant retirements. The Energy Agencies intend to review these developments and incorporate them into the Plan for OTC power plant retirements.
11. The SWRCB would periodically review the Plan and, for each unit with an official reliability designation, modify the OTC permit expiration date to match the reliability designation of the unit. For units without such a designation, the SWRCB would establish compliance requirements and a schedule that transforms these into a water use permit.

Unresolved Issues for this Proposal

Some elements of this proposed approach remain unresolved. These include the following elements that are discussed below:

- Air pollution credits in South Coast Air Quality Management District (SCAQMD) for new power plants displacing OTC power plants, or repowers of existing OTC plants/units to eliminate OTC cooling technologies,
- Sequencing of bidding into utility RFOs versus permitting of a facility,
- Reliance upon conventional generating facilities or preferred technologies,
- Analyses of nuclear generating units at San Onofre and Diablo Canyon, and
- Development of a comprehensive Plan and preferential treatment of elements of the Plan in licensing proceedings compared to proposed facilities not included within the Plan.

Air Pollutant Credits in SCAQMD

Acquiring sufficient air credits through a revitalized Priority Reserve or some other mechanism is necessary for new or repowered generators in the SCAQMD. Only limited OTC retirement can happen without serious reliability consequences unless new or repowered plants can be constructed in the SCAQMD's jurisdiction.[20] The July and November 2008 court decisions in the challenge of the SCAQMD's "priority reserve" requirements has complicated the situation, making it extremely difficult for new power plants to be sited in the Los Angeles Basin. This challenge will make it difficult for most aging power plants to be closed in the Los Angeles coastal region, until new generation or transmission can be constructed. Tradeoffs exist between the need to protect water quality, satisfy air quality requirements and ensure electrical system reliability, while moving toward greater levels of renewable generation as called for by Assembly Bill 32 (AB 32) and the Governor's recent Executive Order calling for increased levels of renewable generation.

[20] Energy Commission Draft Staff Paper, *Potential Impacts of the South Coast Air Quality Management District Air Credit Limitations and Once-Through Cooling Mitigation on Southern California's Electricity System*, February 2009, CEC-200-2009-002-SD.

Sequence of Bidding and Permitting of Proposed Facilities. The sequence of Energy Commission permitting versus generator bidding into an IOU RFO raises several questions:

- Whether power plants would be required to have an Energy Commission permit as a condition of bidding into an IOU RFO.
- Whether power plants would be required to have entered the Energy Commission permitting process and have satisfied specific milestones as a condition of bidding into an IOU RFO.
- Whether winners of an IOU RFO would receive expedited treatment from the Energy Commission in the permitting process compared to other applicants.
- Whether advance guidance can steer proposed power plants into locations likely to be permitted by the Energy Commission.

Conventional versus Preferred Technologies to Replace OTC Facilities

A straightforward solution to the OTC problem is to repower existing OTC facilities by installing a new prime mover that does not use ocean water for cooling.[21] This approach makes use of the existing electrical switchyard, perhaps eliminates consideration of new transmission lines that would allow retirement of some facilities without replacement on site, and essentially preserves the existing electrical system as much as possible. However, this approach would likely have considerable problems in SCAQMD in finding needed air credits and it would fail to address the policy preferences established by the Energy Agencies through the Energy Action Plan process or the need to reduce reliance upon fossil power plants to achieve AB 32 GHG emission reduction goals. Assessing the feasibility of major changes to the system through increased reliance upon renewable, resources, upon rooftop solar PV and other distributed generation technologies, enhanced energy efficiency program impacts reducing load, etc. is necessarily more complex and time consuming than simply endorsing a repowering strategy with little thought to the very long term consequences.

Analyses of Nuclear Generating Units

The four nuclear generating units located at San Onofre and Diablo Canyon represent unique elements of California's electrical generating system and both its positive and negative dimensions. From the perspective of the SWRCB, these four units are the largest source of biologic harm. From traditional air quality criteria pollutant or GHG perspectives, nuclear plants are viewed as highly beneficial, and OTC mitigation requirements that might cause them to shut down would exacerbate overall problems to be overcome. The nuclear units supply a significant percentage of the energy used by California end-users, operating as baseload units with very high capacity factors. Refitting these plants with alternative cooling systems or replacing their capacity and energy require special studies. Unfortunately, studies of the generation versus transmission tradeoffs of the aging fossil fleet may have different results depending on whether the nuclear units are assumed to operate as they do today for an indefinite future, or whether they are retired when their current Nuclear Regulatory Commission permits expire in 2021-2023.

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[21] A prime mover is the basic source of heat energy for running the generating turbine, e.g. a steam boiler, a combustion turbine, a nuclear reactor.

Creation of a Comprehensive Plan to Enable Preferential Treatment for Some Projects

Creating a formal Plan and adopting that Plan through a CEQA-compliance process could have value by subsequently providing preferential treatment (reduced consideration of alternatives, accelerated time schedule, etc.) in the applicable licensing processes for individual projects or facilities included within the Plan. Multiple agencies now have licensing authority over various infrastructure projects, although the Energy Commission licenses the majority of the likely power plant additions and the CPUC licenses the majority of the expected transmission line upgrades. The individual CEQA reviews now implemented for new power plants and transmission lines might be conducted en masse for infrastructure additions part of the Plan. Since the Plan represents a comprehensive, multi-facility replacement of multiple existing facilities, it may be appropriate to revise Energy Agencies' review processes to consider multiple facilities as a package, and to accelerate this consideration. This will be among the alternatives that Energy Agencies will consider when fully developing this alternative approach to OTC mitigation.

Next Steps

This present document represents an attempt to incorporate the feedback to date and internal discussions among the Energy Agencies. The Energy Agencies are now compiling information about the evaluations that are relevant to the OTC power plants in the various regions, and preparing a workplan for those further analyses that are needed. The analytic work will be conducted over the second quarter of 2009.

The Energy Commission will conduct a joint workshop as part of the Energy Commission's 2009 Integrated Energy Policy Report proceeding on May 11, 2009 to solicit input from the generator community, environmental groups, agencies with environmental responsibilities, and the public. The Energy Agencies will participate in this workshop.

Following the workshop, technical staff of the Energy Agencies will determine whether and how to modify this proposal, and inform the SWRCB staff of any such suggested changes.

APPENDIX B: Draft Infrastructure Replacement Milestones and Compliance Dates for Existing Power Plants in California Using Once-Through Cooling

The following tabular chart shows the milestones for each OTC power plant using the key steps of the joint Energy Agency implementation proposal was submitted to the SWRCB on May 19, 2009, and updated on June 22, 2009.

Draft Infrastructure Replacement Milestones and Compliance Dates for Existing Power Plants in California Using Once-Through Cooling

Region (Balancing Authority)	Existing Facility Name	Infrastructure Replacement Milestones[i]							
		CAISO Enhanced LCR Study[ii]	CAISO-CPUC-CEC Infrastructure Replacement Plan[iii]	CPUC Procurement[iv]		CAISO Annual Transmission Plan[8]	CPUC Transmission Permitting[7]	Known Replacement Infrastructure Operational[9]	Unspecified Replacement Infrastructure Operational[9]
				LTPP Approval[v]	Gen Project Approval[vi]				
Humboldt	Humboldt Bay Power Plant[10]	Not required[19]	Pre-Plan[20]	Complete	Complete	Gen solution	N/A	Q3 2010	N/A
San Diego	South Bay Power Plant (partial capacity)[11]	Not required[19]	Pre-Plan[20]	Complete	Complete	Gen solution	N/A	Q4 2009	N/A
	South Bay Power Plant (remaining units)[12]	Not required[19]	Pre-Plan[20]	Trans solution	Trans solution	Complete	Complete	Q3 2012	N/A
	Encina Power Plant	Q4 2009	Q1 2010	2011	2013	2011	2015	N/A	2017
Bay Area	Potrero Power Plant (Unit 3)[13]	Not required[19]	Pre-Plan[20]	Trans solution	Trans solution	Complete	Complete	Q1 2010	N/A
	Contra Costa Power Plant (1 of 2 units)[14]	Not required[19]	Pre-Plan[20]	Complete	Complete	Gen solution	N/A	Q2 2009[21]	N/A
	Contra Costa Power Plant (second unit) Pittsburg Power Plant	Q4 2009	Q1 2010	2011	2013	2011	2015	N/A	2017
Central Coast	Moss Landing Power Plant[15,16]	Q4 2009	Q1 2010	2011	2013	N/A	N/A	N/A	2017
	Morro Bay Power Plant[16]	Not required	Pre-Plan	complete	complete	N/A	N/A	Q1 2009[22]	N/A
Ventura/Big Creek[17]	Mandalay Generating Station Ormond Beach Generating Station	Q4 2010	Q2 2011	2013	2015	2012	2016	N/A	2020
Los Angeles Basin[17] (CAISO)	El Segundo Generating Station Huntington Beach Generating Station Redondo Generating Station Alamitos Generating Station	Q4 2010	Q2 2011	2013	2015	2012	2016	N/A	2020
Los Angeles Basin[17] (LADWP)	Haynes Generating Station[18] Harbor Generating Station[15,18] Scattergood Generating Station[18]	Not under The California ISO balancing authority or the CPUC jurisdiction. The Energy Commission is conferring with LADWP to understand in-basin capacity requirements and processes for accomplishing OTC mitigation.							
Nuclear Plants	Diablo Canyon Power Plant San Onofre Nuclear Generating Station								

[i] These infrastructure milestones assume no litigation about facility permits following appropriate agency approvals.

[ii] California Independent System Operator Corporation (The California ISO) would conduct an enhanced Local Capacity Requirement (LCR) study identifying the impacts of specific OTC retirements or transmission developments on the local area's LCR projections 10 years out. The California ISO will use assumptions about load and generation developed jointly with the California Energy Commission (Energy Commission) and the California Public Utilities Commission (CPUC).

[iii] The Infrastructure Replacement Plan developed jointly and updated by the California ISO, Energy Commission, and the CPUC would identify the complete set of infrastructure needed to make OTC plants/units redundant for grid reliability. It would advise the SWRCB about the reliability designations of specific power plants.

[iv] CPUC would modify its Long-Term Procurement Plan (LTPP) proceeding and procurement processes to require the investor-owned utilities (IOUs) to assess replacement infrastructure needs and conduct targeted request for offers (RFOs) to acquire replacement or repowered generation capacity. CPUC also has authority to approve cost-based contacts under AB 1576.

[v] CPUC has authority to order the IOUs to procure new (or repowered) fossil generation for system reliability in the LTPP proceeding. LTPP proceedings are conducted on a biennial cycle and plans are normally approved in odd-numbered years.

[6] Once authorized to procure by a CPUC LTPP decision, it takes 18 months for the IOUs to issue an RFO for generation (new or repowered), sign contracts and submit applications to the CPUC for approval. Approval by the CPUC takes 9 months. If the contract involves a facility already licensed by the Energy Commission, then financing and construction can begin. Generation permitting for thermal technologies >50 MW in capacity is under Energy Commission authority, and may take place before, after or during the CPUC contract approval process. The Warren-Alquist Act authorizes the Energy Commission to license certain categories of power plants and related structures. The Energy Commission's siting process has been determined to be a certified regulatory program under the California Environmental Quality Act (CEQA) and the functional equivalent of preparing environmental impact reports (EIRs). The Energy Commission is the lead agency and consults with other relevant agencies. The standard licensing process is normally conducted in 12 months, but streamlining of the permitting process may be an option so multiple facilities can be considered as a package (planning level EIR). Reviews should be somewhat faster because impacts to water resources are by definition minimized; impacts to the grid reliability are already considered and mitigated; and conformity to state laws and regulation has been considered under the Plan.

[7] Transmission permitting is under CPUC authority. Proposed transmission facilities to meet needs identified in the California ISO Annual Transmission Plan to replace OTC plants/units would be brought to the CPUC for approval.

[8] Transmission solutions (upgrade and/or new addition) that would make specified OTC system redundant would be analyzed in the California ISO Annual Transmission Plan. The California ISO will consider SWRCB directives and schedules limiting or canceling water permits required to operate OTC plants/units in the 2011 and subsequent annual Transmission Planning Process (TPP). The California ISO will conduct analysis as part of its TPP reflecting projected OTC plant/unit retirements as a result of SWRCB directives and schedules, which shall be incorporated in to the California ISO's annual Transmission Plan that serves as the basis for further transmission upgrades or additions.

[9] These compliance dates may change subject to the California ISO-Energy Commission-CPUC Infrastructure Replacement Plan produced in Q1 2010 and updated periodically. All dates assume a generation solution that requires an Energy Commission permit. If a permit has been acquired prior to CPUC contract approval, then an earlier on line date is possible. If transmission solutions are selected, then longer time lines would be expected.

[10] Humboldt Repower generation project is approved by the CPUC and expected operational by Q3 2010. This new infrastructure will eliminate OTC at the Humboldt Power Plant.

[11] Otay Mesa Power Plant is in construction and expected operational by Q4 2009. This new infrastructure is expected to displace a portion of the need for the capacity of the South Bay Power Plant.

[12] Sunrise Powerlink transmission project is approved by the CPUC and expected operational in 2012. This new infrastructure is expected to displace the need for remaining South Bay Power Plant capacity.

[13] TransBay Cable transmission project is expected operational by Q1 2010. This new infrastructure is expected to replace the need for Potrero Unit 3.

[14] The new Gateway Generating Station became operational in January 2009. This new infrastructure is expected to replace the need for one unit at the Contra Costa Power Plant.

[15] Units that have recently been repowered will be addressed separately.

[16] Not needed for local network reliability, according to a November 26, 2008 preliminary The California ISO Study, although may be needed for system resource adequacy requirements.

[17] Due to siting/land use and air quality constraints, it is likely that a combination of new generation and transmission infrastructure will be necessary to replace the need for OTC plants/units in the Ventura/Big Creek and L.A. Basin regions.

[18] Owned and operated by the Los Angeles Department of Water and Power, its own balancing authority (not controlled by The California ISO).

[19] No further study is required. Existing studies are sufficient to determine reliability designation of specified OTC facilities.

[20] Replacement infrastructure sufficient to determine reliability designation of specified OTC facility was identified prior to development of the Infrastructure Replacement Plan.

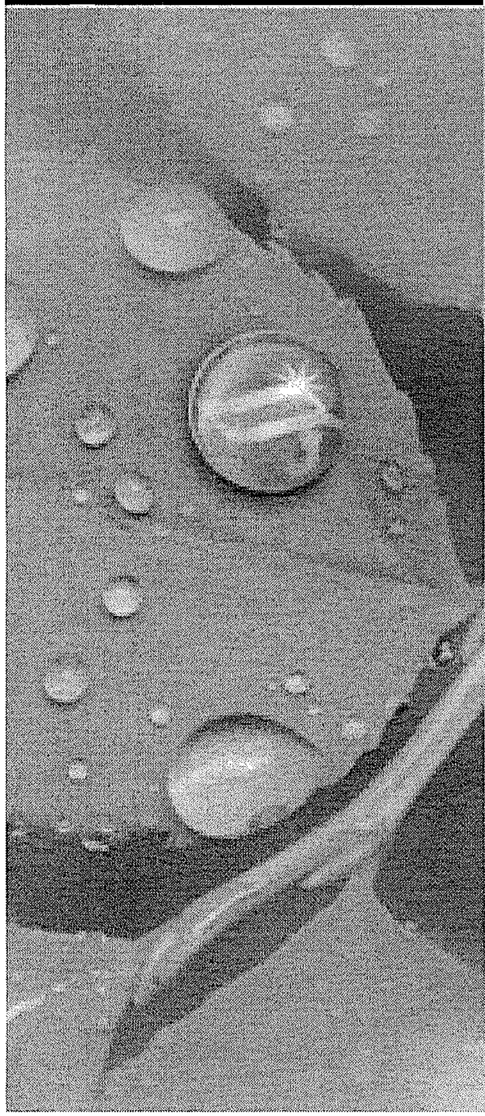
[21] Contra Costa Power Plant is under contract to PG&E until 2011.

[22] Morro Bay units 3-4 have contracts with SCE through Q4 2011.

2. Preliminary California ISO Scenario Analysis, "Impacts on Electric System Reliability Restrictions on Once-Through Cooling in California," November 25, 2008

Impacts on Electric System Reliability from Restrictions on Once-Through Cooling in California

California ISO
Your Link to Power
10 Year Anniversary



PRELIMINARY California ISO Scenario Analyses

David Le and Robert Sparks
Division of Market & Infrastructure Development
California ISO

Updated Presentation
November 25, 2008

Overview

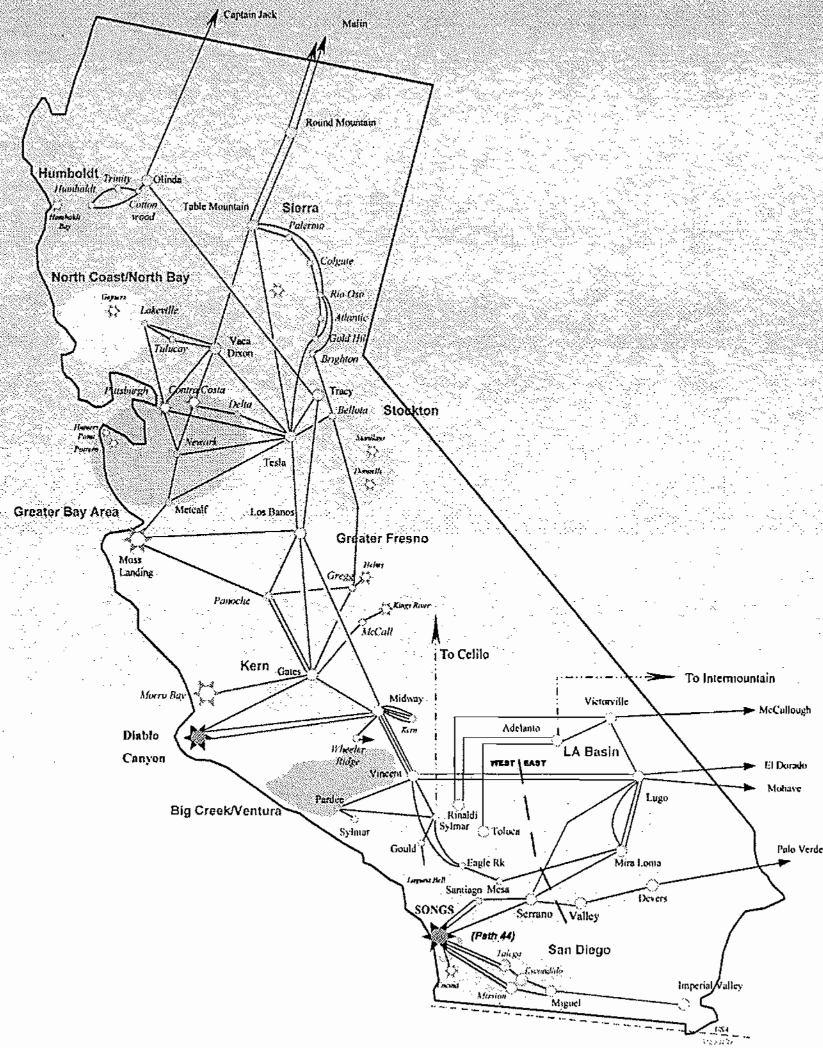
1. Overview of the ISO Preliminary Assessment
2. Northern California – Identified Impacts To Transmission System
3. Southern California – Identified Impacts To Transmission System
4. Preliminary Recommendations, Recaps of ISO Assessment and Discussion of Preliminary Mitigations

1. Overview of the ISO Preliminary Assessment

Overview of the Preliminary Assessment

- The ISO gathered information from owners and other sources on Once Through Cooling (OTC) resources concerning their preliminary plans for retirement, repowering and/or retrofitting their power plants.
- This information formed the basis of the scenarios in this study to demonstrate what system supply requirements and transmission upgrades would be required in the absence of an OTC and/or OTG resource.
- The presentation is organized by Local Capacity Areas, specifically Greater Bay Area, Big Creek/Ventura, L.A. Basin and San Diego.
- Sunrise, Tehachapi, and PV-Devers 2 transmission projects were assumed in-service.
- New generation under construction was assumed in-service (i.e., Inland Empire, Gateway, Otay Mesa).
- Committed energy efficiency programs are included in the California Energy Commission (CEC) load forecast.

Local Capacity Requirement Areas in ISO



Local Capacity Requirements -- ISO Statutory Obligation Regarding Safe Operation

- The ISO must maintain the system in a safe operating mode at all times.
- This obligation translates into respecting reliability criteria at all times.
  - During normal operating conditions **A (N-0)**
  - Protect for all single contingencies **B (N-1)**
  - Protect for common mode **C5 (N-2)** double line outages
  - After a single contingency the ISO must readjust system to support the loss of the next most stringent contingency **C3 (N-1-1)**

- In order to meet the reliability criteria in many urban areas, local generation must operate to supplement the transmission system (**Local Capacity Requirements (LCR) Generation)**

Overview of Key Components for the Studies

- The ISO limited evaluation to impacts to the ISO controlled grid.
- Committed energy efficiency programs are included in the CEC load forecast.
- Other key factors, although not studied in detail, also need to be considered in the OTC evaluation:
  - Resource Adequacy – About 12,000 MW (4,479 MW in Northern California and 7,416 MW in Southern California) needed to replace the impacted generation
  - Support for 20% and 33% RPS – OTC units needed for ramping capability in support of integrating renewable generation to meet 20% and 33% RPS
  - Transmission Siting Challenges – Siting approvals necessary to develop high voltage out-of-state, in-state, and in-urban-area transmission projects
  - Generation Siting Challenges – Availability of air emission credits in Southern California and other siting issues complicate development of replacement generation
  - Import Capability – Need for increased transmission import capability into California

2. Northern California – Identified Impacts to the Transmission System

Scenario Findings

Humboldt Local Capacity Area

- The Humboldt area contains 105 MW of OTC units.
- PG&E has firm plans to retire this generation.
- Humboldt will be replaced by 163 MW of new generation at the same location.
- No local reliability issues expected.

Units not in a Local Capacity Area

- **Morro Bay** Power Plant
  - 673 MW of OTC units
  - Not required to meet current local reliability needs
- **Diablo Canyon** Power Plant
  - 2240 MW of OTC units
  - Nuclear powered (no CO2 Emissions)
  - Not removed in the analysis

Scenario Findings (cont'd)

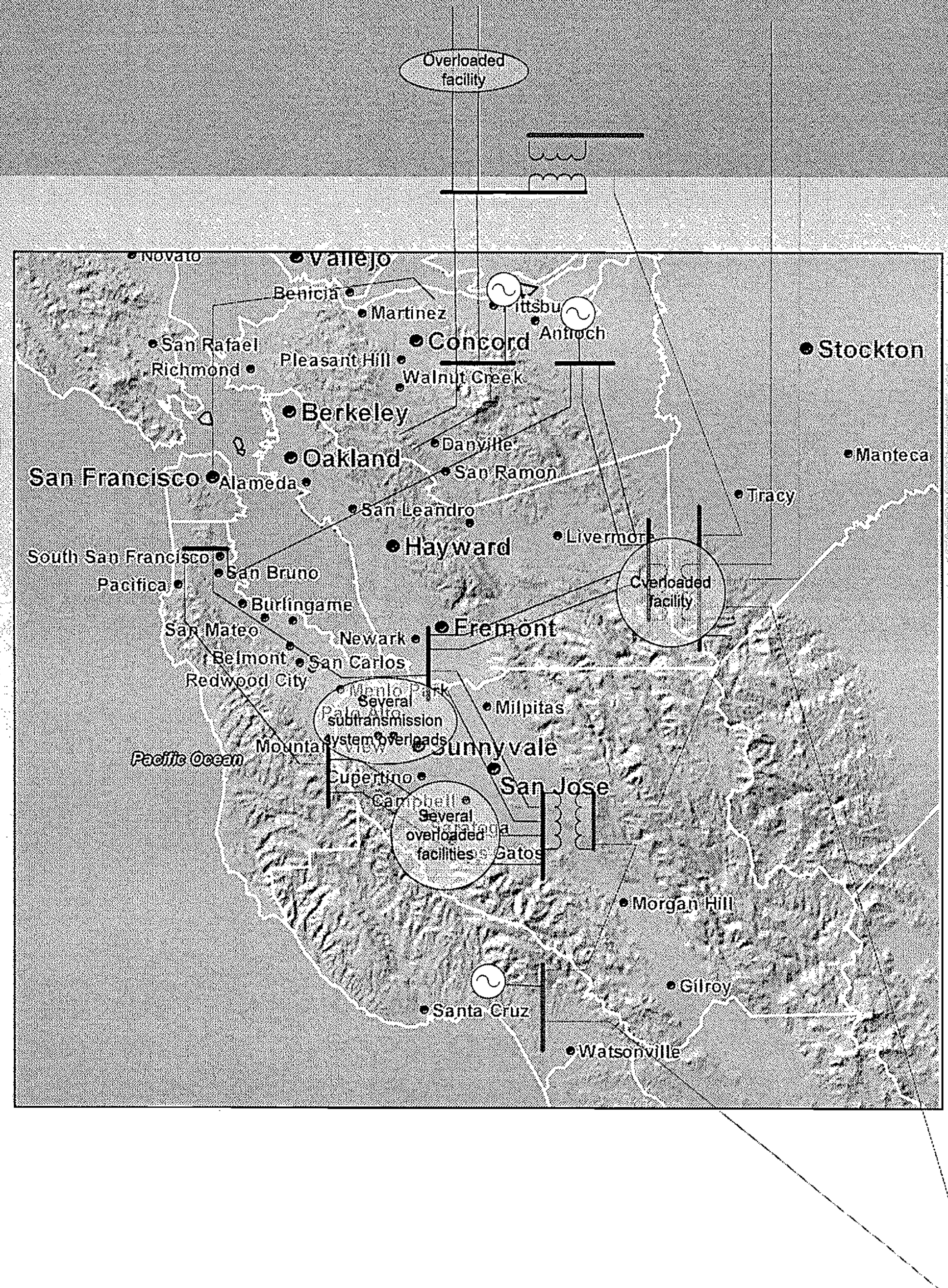
- **Moss Landing** Power Plant:
  - 2530 MW of OTC units
  - Two simple cycle OTC units and two combined cycle OTC units
  - Analysis assumes that the owner of the existing new and efficient combined cycle units will take the steps necessary to ensure their continued operation

San Francisco Bay Area (SFBA) Local Capacity Area

- Once-through-cooled Generation
  - Three power plants
  - Six generating units
  - 2191 MW of generating capacity
    - This includes 682 MW from Pittsburg Power Plant Unit Number 7. The unit does not rely on once-through-cooling, but air emission issues could force its retirement in the near future.
- In the short-term, removal of this generating capacity could require immediate and costly transmission upgrade costs, requiring up to five years to complete.
- In the long-term, much greater costs for a new 500 kV/230 kV substation in addition to costs incurred in the short-term could be necessary, requiring up to ten years to complete.
- A well coordinated policy could rely exclusively on the long-term transmission solution and avoid the costly short-term option.

Transmission Reliability Criteria Violations Identified in SFBA Scenario

- Immediate and costly mitigation costs
- Non-wires alternatives not considered



3. Southern California (ISO) – Identified Impacts to the Transmission System

Once Through Cooling Generating Units in Southern California (ISO Controlled Grid)

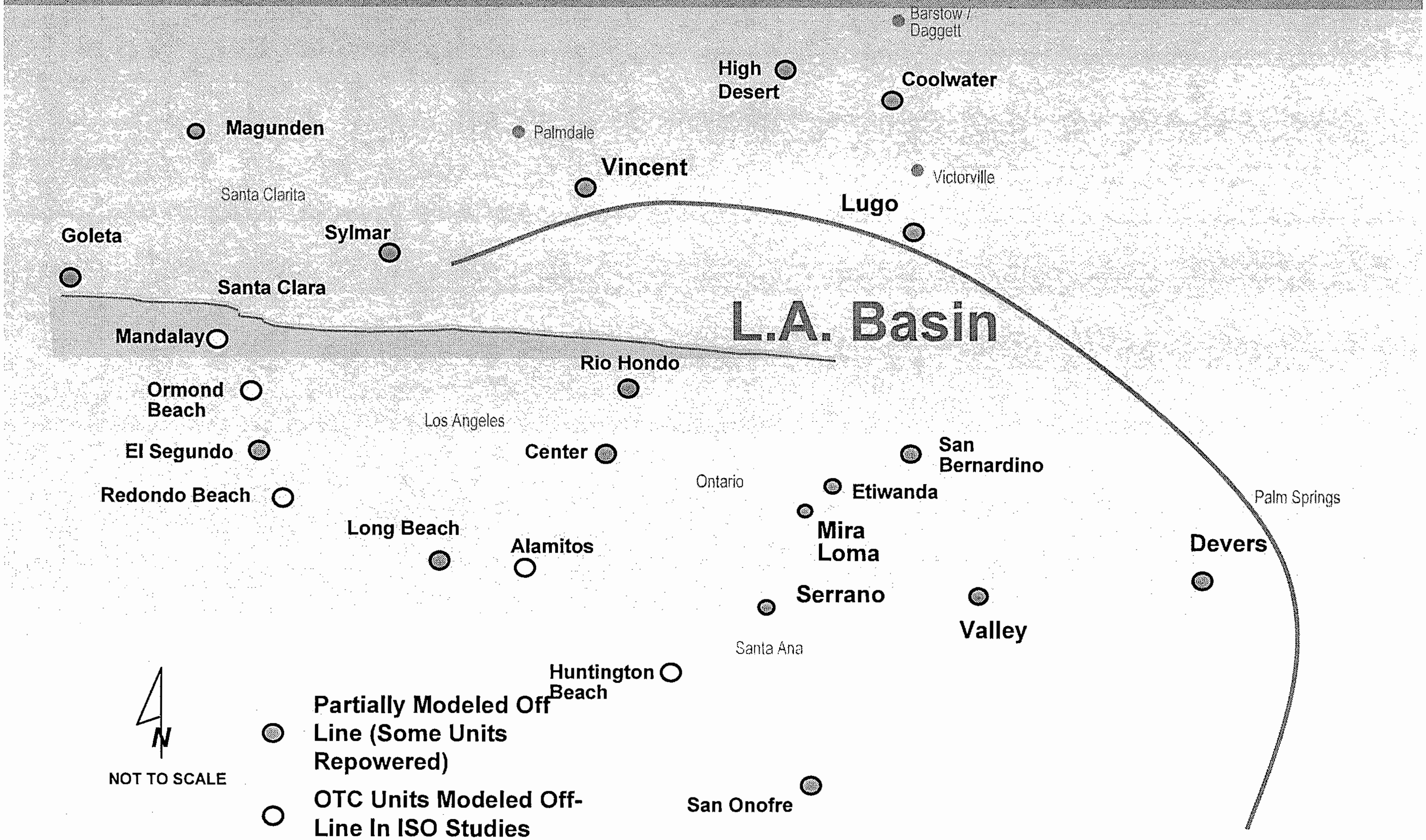
- There are nine power plants, including one nuclear generating station
  - Alamitos, El Segundo, Encina, Huntington Beach, Mandalay, Ormond Beach, Redondo Beach, South Bay
  - San Onofre Nuclear Generating Station

- Criteria for selecting which OTC units to be modeled off-line in the study:
  - High heat rate (> 7500 MMBtu)
  - Low capacity factors ($\leq$20%)
  - No plans to re-power or convert to acceptable method of cooling
  - Older than 35 years
  - No RMR designation

Once Through Cooling Generating Units in Southern California (ISO Controlled Grid)

- There are 8 plants (26 units) that are impacted
- Total potential MW capacity at risk = 7,416 MW.
- Re-powered units that were included in the studies:
  - El Segundo Units 1 & 2 (550 MW)
  - Encina Units 1 – 3 (550 MW)

OTC Units in L.A. Basin



Preliminary Study Results – Bulk Transmission Impacts

- Path 26 (Midway – Vincent) flow (5,321 MW) exceeded the WECC-approved rating (4,000 MW N-S)
- Path 66 (California – Oregon Interface or COI) flow (5,766 MW) exceeded the WECC-approved rating (4,800 MW N-S)
- Southern California Import Transmission (SCIT)'s limit is exceeded (20,963 MW vs. 16,200 MW); 16,200 MW is the operational limit.
- SDG&E's import limit is exceeded by approximately 200 MW.
- Low voltage was identified at many 500kV and 230kV buses in Southern California.

Preliminary Study Results – Bulk Transmission Impacts (cont'd)

- The 500/230kV transformers at three major 500kV substations experience contingency overloading concerns:
  - Vincent (northern L.A. County), Serrano (Orange County) and Valley Substations (San Bernardino County)
- Major 500kV line loadings exceed its normally rated rating
  - Midway - Vincent 500kV line # 2 exceeds its rating by 6%
  - Hassayampa – N.Gila 500kV line loading exceeds its rating by 14% under normal conditions
  - Imperial Valley – N. Gila 500kV line loading exceeds its rating by 8% under normal conditions
- Southern California is subject to voltage instability (post-transient) under various 500kV N-1, N-2 and critical G-2 (i.e., nuclear units) contingencies at peak load conditions

Preliminary Study Results – Bulk Transmission Impacts (cont'd)

- Southern California is subject to transient voltage dip exceeding WECC planning limit under G-1/N-1 contingency conditions and transient voltage instability with PDCI outage
- Southern California is subject to transient undamping conditions under various N-2 or G-2 (nuclear units) contingencies

Preliminary Study Results – Local Transmission Impacts

Local Transmission Impacts:

- Two 230kV local transmission lines (Chino – Mira Loma #3 line and Barre – Ellis 230kV line) are overloaded under contingency or normal conditions
- Ten 69kV transmission facilities in SDG&E area are subject to thermal overloadings

Preliminary Transmission Mitigations

<u>The following $4.45 Billion in total cost estimates are preliminary and based on planning level estimates (+/- 50%)</u>

- Construct two additional 500/230kV substations to serve load in the absence of 7,416 MW of generation in the L.A. Basin and San Diego County
  - Estimated cost: $1 billion
- Re-arrange 500kV lines to new substations and increase Path 26 (Midway – Vincent) as well as Path 66 (COI) ratings by constructing two additional 500kV lines (if economically justifiable)
  - Estimated cost: $2 billion
- Other potential transmission upgrades in the Northwest to accommodate the increase in import capability to California
  - Estimated cost: $1 billion
- Other upgrades that include dynamic reactive support
  - Estimated cost: $300 million
- Transmission upgrades to mitigate local transmission facility overloads
  - Estimated cost: $150 million

Other Cost Impact Considerations

- Resource impacts to Southern California
  - About 7,416 MW of resources in ISO Southern grid area needed to replace OTC generation
- 20% and 33% RPS Implementation
  - May need additional regulation and ramping requirements for integration of intermittent renewable resources

4. Preliminary Recommendations, Recaps of ISO Assessment and Discussion of Preliminary Mitigations

Preliminary Recommendations

1. Connect Once-Through-Cooling policy implementation to the California Public Utility Commission (CPUC) Long Term Procurement Plan (LTPP) process
   - Resources impacted by OTC policy implementation needed for RA as well as LCR requirements
   - Should be considered in multi-year Resource Adequacy (RA) requirements
   - Even if $4 to $5 billion of transmission upgrades can be implemented, replacement generation still needed to meet RA requirements
   - Procurement contracts could be conditioned on commitment to repower and include repowering costs
   - Timing critical to maintain system reliability and resource adequacy

Preliminary Recommendations (cont'd)

2. Re-powering existing generation should be the implementation priority.
   - Reliability requirements mean Timeline for implementation should allow for an orderly shutdown and replacement process
   - For generation that can't be replaced in its existing location, adequate time needed to implement transmission mitigations
3. The nuclear generating units should be dealt with separately due to resource adequacy implications and tradeoffs with greenhouse gas and air quality issues.

Recaps of ISO Reliability Assessment Results

- The ISO preliminary assessment investigated impacts to transmission system
- Further evaluation of the impact of 20% and 33% RPS on system operations still needed
- Evaluation addressed four LCR areas where OTC generating units located:
  - Greater Bay Area
  - Big Creek / Ventura
  - Los Angeles Basin (L.A. Basin)
  - San Diego Area

- Greater Bay Area reliability concerns smaller in scale compared to Southern California concerns; further analyses still needed for a balanced approach between transmission and/or generation mitigations

Recaps of ISO Reliability Assessment Results

- For San Diego Area:
  - With the Sunrise Power link in service, Encina partially repowered and South Bay retired, the ISO estimated that the area is deficient by 200 MW.
  - If Sunrise Powerlink is not in-service, the area resource deficiency would grow to 1,200 MW.
  - Other local sub-transmission (69kV) upgrades are needed to mitigate local reliability concerns (i.e., facility overloadings)
- For L.A. Basin and Big Creek/Ventura Areas:
  - Generating units from all six power plants (i.e., Alamitos, El Segundo, Huntington Beach, Mandalay, Ormond Beach and Redondo Beach) are needed for LCR and Resource Adequacy (RA)
  - South Coast Air Quality Management District (SCAQMD) priority reserve issues need to be resolved.

Recaps of ISO Reliability Assessment Results

- For L.A. Basin Area (cont'd):
  - If priority reserve issues are not resolved:
    - Existing power plants are needed for maintaining local reliability in an LCR area and for Resource Adequacy (RA) requirements, OR
    - If existing OTC power plants are retired or shut down, then about $4 to $5 billion (2008 dollars) of identified conceptual transmission upgrades, if determined to be feasible, are needed
    - Additional transmission costs would be incurred to mitigate potential out-of-state transmission impacts due to increased imports into ISO Control Grid

Discussion of Preliminary Mitigations

- There are two primary mitigations:
  - Transmission mitigations
  - Generation Re-powering

- Significant barriers related to transmission mitigations:
  - Siting difficulties
  - WECC entities must concur with proposed California import interfaces (intertie) and major internal path rating increases
  - Dependent on neighboring State regulatory agencies in granting environmental permits to construct inter-state lines
  - Cost and siting of the 8,000-12,000 MW of replacement generation

Discussion of Preliminary Mitigations (cont'd)

- Generation Re-powering:
  - Generally speaking, appears more economic, feasible and reliable than transmission-only alternatives.
  - Preserves or closely maintains resources needed for RA
  - Provides and maintains ramping capability needed for integration of renewable resources
  - Typically can be implemented in a shorter time frame than transmission mitigations

3. "Potential Impacts of the South Coast Air Quality Management District Air Credit Limitations and Once-Through Cooling Mitigation on Southern California's Electricity System"; Energy Agencies' Staff Draft Paper, February 2009

POTENTIAL IMPACTS OF THE SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT AIR CREDIT LIMITATIONS AND ONCE-THROUGH COOLING MITIGATION ON SOUTHERN CALIFORNIA'S ELECTRICITY SYSTEM

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STAFF DRAFT PAPER

February 2009
CEC-200-2009-002-SD

Overview

As California's demand for electricity increases, Southern California continues to be the region most vulnerable to supply shortages. In addition to long-term contract and utility-owned generation, Southern California utilities rely on electricity purchased from aging power plants under short- and long-term contracts to maintain sufficient reserve margins and provide for local area reliability, specifically in the Los Angeles Basin. Despite significant amounts of energy efficiency and roof top solar photovoltaic systems included in the Energy Commission's demand forecasts, new or repowered natural gas generation is required in Southern California for five important reasons:

- To "firm up" the intermittency characteristics of renewable generation
- To address once-through cooling (OTC) impacts
- To replace aging plants and improve efficiency of the generating fleet
- To meet load growth after demand-side measures have been installed; and
- To satisfy overall system resource needs

New generating capacity development to replace these aging power plants is critical to achieving environmental improvements, including reduced greenhouse gas (GHG) emissions from more efficient use of natural gas and reduced impacts on coastal and marine environments by moving away from once-through-cooling for power generation. However, recent court rulings limiting the supply of air emissions credits in the South Coast Air Quality Management District (SCAQMD) present new challenges for California to achieve these important environmental improvements while at the same time ensuring sufficient generating supplies for system resource needs and local area reliability.

Southern California air basins also have some of the worst air quality in the nation, resulting in stringent local air quality requirements, including offsetting new sources of emissions with reductions in emissions from existing sources. These offsets, or emission credits, are in short supply in the SCAQMD, and constrain the ability to license new power plants or repower existing aging plants in Southern California. In 1990, the SCAQMD established a Priority Reserve of emission credits that were set aside for use by entities that serve a public interest, but did not explicitly include power generation as an industry eligible to use the credits.

In August 2007, the SCAQMD amended its Priority Reserve Rules by establishing air quality and economic criteria that allowed these offsets to be purchased for new power plants licensed by the Energy Commission. The SCAQMD, under Rule 1309.1, limited these power plant credits, requiring developers to have a one-year power sales contracts and a license from the Energy Commission to construct their facility before the SCAQMD Board would release any credits for that facility. Plants being proposed by municipal utilities were allowed only enough credits to build projects that serve their native load. The SCAQMD also limited the total amount of new electricity generating capacity that could access Priority Reserve credits to no more than 2,700 megawatts.

The SCAQMD Priority Reserve Rule was challenged in Superior Court and in July 2008, the court decision found the air district's California Environmental Quality Act (CEQA) analysis inadequate and indicated that a sufficient environmental document would require significant new analysis that the SCAQMD believes it cannot reasonably provide. As a consequence, the SCAQMD is unable to issue any offsets for power plants or for any facilities requiring a permit for emissions. The SCAQMD is now working to modify its regulations to allow permits for non-power plant facilities, but has no specific plans to develop new rules specific to power plants. A second, unresolved lawsuit in federal court is challenging whether the credits used to justify the amount of emission in the priority reserve bank have been tracked and accounted for properly. (See Attachment 2 for a complete account of these details.)

The Energy Commission, in its *2005 Integrated Energy Policy Report*, called for the retirement, replacement, and/or repowering of aging power plants. These power plants operate at high heat rates when compared with new generation technologies resulting in less efficient use of natural gas and higher levels of air pollutants, including GHG emissions. The Energy Commission also recommended that the California Public Utilities Commission (CPUC) ensure that long-term resource procurement explicitly takes into account the retiring, replacing, and/or repowering aging power plants with cleaner, combustion-based technologies that operate at higher efficiencies. This includes aging power plants in the Los Angeles Basin. In its 2006 LTPP decision, D.07-12-052, the CPUC included substantial retirements in determining future investor owned utility (IOU) needs.

Previous studies of large amounts of renewable generation technologies have shown two operating characteristics that require dispatchable generating resources to augment intermittent renewables: (1) the uncertainty of wind generation on a real time basis, requiring dispatchable generation to "ramp" up and down as wind output fluctuations, and (2) to address the systematic output variations during the year, in particular, the mismatch between annual peak loads under extreme temperatures and the expected lower generation from wind resources under such conditions. As the state's aged steam boiler power plants have become less economic, they have gradually shifted their operational patterns from baseload to less certain load following. The *2009 Integrated Energy Policy Report* will examine this issue in greater depth this year.

In addition, 13 of the state's 19 coastal power plants – which face challenges from using ocean water for cooling – are located in the southern part of the state. Once-through cooling is a technology that uses seawater to cool and re-condense superheated steam after it has been used to generate power and has significant impacts on marine organisms and ocean habitat. The federal Clean Water Act requires facilities to address these impacts, and the State Water Resources Control Board (SWRCB) is moving forward with stringent limitations on OTC facilities to implement these requirements. In its March 2008 preliminary OTC mitigation policy proposal, SWRCB suggested fossil power plants operating at less than 20 percent annual capacity factor have to mitigate OTC by converting to wet cooling towers (or the water flow equivalent). **Figure 1** shows the aging power plants using OTC (which are located within the SCAQMD jurisdiction area) the power plants that Priority Reserve credits have been requested, and the boundaries of the California Independent System Operator's (California ISO) Los Angeles Basin load pocket.

If new gas-fired power plants cannot be licensed in the Los Angeles Basin because air emission credits from the SCAQMD priority reserve are unavailable and other rules favorable to power plant development are disallowed, system reliability will require continued and ongoing operation of aging, less efficient, higher emission power plants to maintain planning reserve margins between 15-17 percent. Although the SWRCB could consider delaying the forced retirement of OTC power plants, it is unclear how long such a delay can continue and remain consistent with the U.S. Environmental Protection Agency's (U.S. EPA) enforcement of Clean Water Act provisions.

This shortage of emission credits could have a negative impact on Southern California's ability to meet the California Independent System Operator's (California ISO) summer peak and local capacity requirements as early as 2011. Local capacity requirements are designed by the California ISO to ensure that there is sufficient generation to provide uninterrupted service during all hours even if a major power plant or transmission line fails. In 2008, the Los Angeles Basin is meeting nearly half of its electrical load with local generating capacity, including aging power plants.

Currently, the planning processes for new generation and transmission projects do not address the scale and schedule of proposed likely retirements of existing OTC power plants, thus inhibiting the replacement of these power plants with new infrastructure in the Los Angeles Basin.[1] Under the current emission credit limitations, the environmental improvements that accompany investments in new and updated infrastructure are delayed and the long-term reliability of the region's electricity supplies is jeopardized.

This paper provides background and analysis of the potential impact on the overall supply/demand balance for electricity – expressed as reserve margins – for Southern California as well as local reliability concerns[2] from the SCAQMD litigation and the SWRCB effort to mitigate the environmental effects of OTC.

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[1] In late 2008, California ISO conducted an abbreviated assessment of shutdowns of a large portion of the non-nuclear OTC fleet to determine the transmission and other system operational impacts. This analysis is found at: http://www.caiso.com/208b/208b8ac831b00.pdf

[2] This quantitative analysis only addresses the Los Angeles Basin load pocket within the California ISO balancing authority (control area). Some of the same issues exist for the Los Angeles Department of Water and Power control area, but these have not yet been addressed.

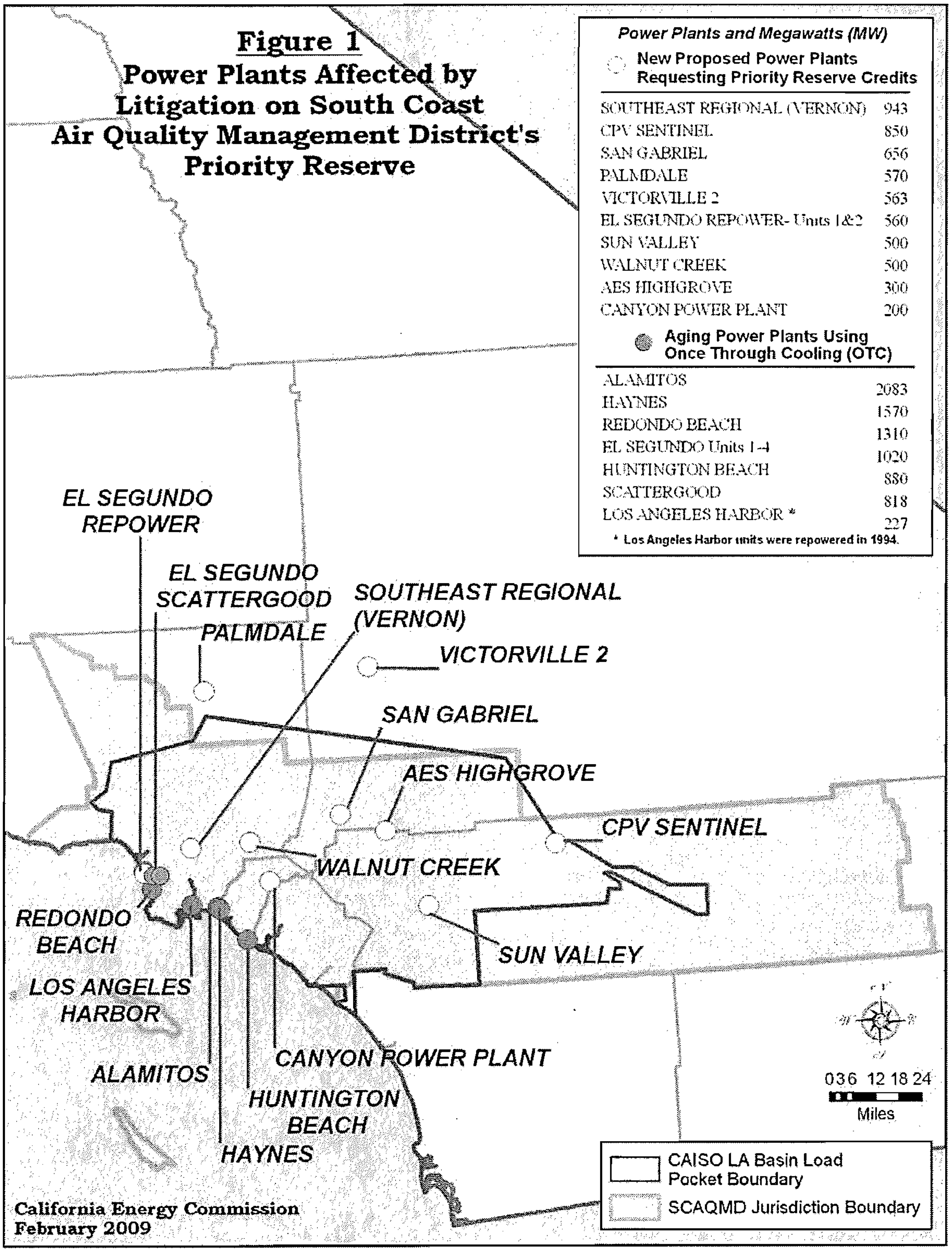
Figure 1
Power Plants Affected by
Litigation on South Coast
Air Quality Management District's
Priority Reserve
Power Plants and Megawatts (MW)
New Proposed Power Plants
Requesting Priority Reserve Credits
SOUTHEAST REGIONAL (VERNON) 943
CPV SENTINEL 850
SAN GABRIEL 656
PALMDALE 570
VICTORVILLE 2 563
EL SEGUNDO REPOWER- Units 1&2 560
SUN VALLEY 500
WALNUT CREEK 500
AES HIGHGROVE 300
CANYON POWER PLANT 200
Aging Power Plants Using
Once Through Cooling (OTC)
ALAMITOS 2083
HAYNES 1570
REDONDO BEACH 1310
EL SEGUNDO Units 1-4 1020
HUNTINGTON BEACH 880
SCATTERGOOD 818
LOS ANGELES HARBOR * 227
* Los Angeles Harbor units were repowered in 1994.
EL SEGUNDO
REPOWER
EL SEGUNDO
SCATTERGOOD
PALMDALE
SOUTHEAST REGIONAL
(VERNON)
VICTORVILLE 2
SAN GABRIEL
AES HIGHGROVE
CPV SENTINEL
WALNUT CREEK
REDONDO
BEACH
SUN VALLEY
LOS ANGELES
HARBOR
CANYON POWER PLANT
ALAMITOS
HUNTINGTON
BEACH
HAYNES
0 3 6 12 18 24
Miles
CAISO LA Basin Load
Pocket Boundary
SCAQMD Jurisdiction Boundary
California Energy Commission
February 2009

South Coast Air Quality Management District Court Litigation

In recent years, new power plants not relying on OTC have been proposed and licensed in the Los Angeles Basin. As directed by the federal Clean Air Act, new facilities can only be built if they can provide credits for their emissions.[3] These offsets are almost non-existent and if available, expensive to buy. Mitigation requirements for criteria pollutant emissions from new and repowered power plants in the Los Angeles Basin are governed by the SCAQMD. The SCAQMD has provided two paths for licensing these facilities, one for repowering of existing facilities, and one for new facilities. Repowering proposals are addressed by Rule 1304, which expedites licensing of existing facilities provided total capacity does not increase. For new facilities, the basic premise is that such facilities have to follow the general process for large new stationary sources and find the necessary emission reduction credits through offset markets. When offset market options have been exhausted, the only feasible source of such offsets is the SCAQMD Priority Reserve, an offset bank traditionally available only for public infrastructure, such as landfills or water treatment plants. In 2007, the SCAQMD attempted to make a portion of the Priority Reserve available for new power plant facilities by amending its rules.

The SCAQMD amended its Priority Reserve rules (Rule 1309.1) in August 2007 by establishing air quality and economic criteria allowing priority reserve credits to be purchased for new power plants that were licensed by the Energy Commission. The SCAQMD rulemaking was successfully challenged in Superior Court regarding the sufficiency of its environmental analysis. The July 2008 trial court ruling found the air district's CEQA analysis inadequate for several reasons, and indicated that an adequate CEQA document would require elaborate new analysis that the SCAQMD believes it cannot reasonably provide. As a consequence, the SCAQMD cannot issue any credits for power plants. A second ruling by the same Superior Court judge has disallowed use of Priority Reserve credits for any purpose. A second lawsuit in federal court is challenging whether the credits used to justify the amount of emissions in the Priority Reserve bank have themselves been tracked and accounted for appropriately. This suit has not yet been resolved.

The SCAQMD requires power plant proponents to perform a "due diligence" effort to purchase emission reduction credits through market mechanisms before it would consider applications for credits through its Priority Reserve. Efforts by developers to find credits on the open market, however, have been mostly unsuccessful, primarily for particulate matter ten microns or smaller (PM10). Emission reduction credits are simply not available from market sources or through other mechanisms at prices allowing new generation project development. The owners (utility and private) of offsets from previous shutdowns of older power plant units and/or from other large, stationary emission sources, such as refineries, are holding onto them to accommodate their own future growth plans.

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[3] Attachment 2 contains a fuller discussion of the SCAQMD new source review rules and emission offset requirements.

Other efforts, such as offsets from mobile sources (for example, commercial truck fleets) have not been allowed by the U.S. EPA since there is no guarantee they would permanently provide a sufficient amount of emission reduction.

The impacts from this court ruling are that no large new stationary emission sources, such as gas-fired power plants, can be permitted in the SCAQMD region until the SCAQMD creates a rule satisfying court requirements. Such an effort is now underway, but only for those facilities for which Priority Reserve was originally designed. No comparable effort is planned for power plants at this time. Thus, the process for permitting projects in adjacent air basins using credits from the SCAQMD Priority Reserve is similarly constrained.

State Water Resources Control Board Policy

For several years, the SWRCB and the U.S. EPA have been attempting to implement the federal Clean Water Act section 316(b) regulation governing power plant use of ocean water for OTC. The SWRCB's March 2008 preliminary policy proposal included a phased compliance time extending to 2021. Three classes of power plants would be required to reduce ocean-cooling water comparable to using a wet cooling tower, that is, ocean water could only be used for makeup of evaporative losses.[4] Fossil fuel plants with capacity factors at or below 20 percent would be required to comply by 2015, other fossil fuel plants would have to comply by 2018, and the four nuclear units (two units at each of two plants) would have to comply by 2021. A summary of two types of generating capacity affected by OTC policies, referred to as OTC capacity in this paper, which have been designated for compliance by 2015 (annual capacity factor <20 percent) and 2018 (annual capacity factor >20 percent) in the proposed OTC policy, is shown in **Table 1**.

Table 1: OTC Fossil-Fueled Capacity in the Los Angeles Area Scheduled for Compliance in 2015 and 2018 (in Megawatts)

Control Area	Annual Capacity Factor < 20% (2015)	Annual Capacity Factor > 20% (2018)	Total Capacity (MW)
California ISO	4420	440	4860
LADWP	1487	1154	2641
Total	5907	1594	7501

The SWRCB's proposed policy to comply with section 316(b) of the Clean Water Act would impact about one-half of the power plants in the Los Angeles Basin, translating into millions of dollars of retrofitting costs on the affected plants, and may result in some operators choosing to

[4] The SWRCB estimates this is approximately 98 percent reduction in water use.

retire the facilities rather than invest the additional capital. Alternatively, some owners have suggested they would repower if long-term contracts can be secured to allow reasonable profits. The energy agencies (Energy Commission, CPUC, and California ISO) have proposed an alternative implementation proposal to the SWRCB that links shutdown of OTC facilities to creating a replacement infrastructure, most likely a combination of new power plants, repowering of some OTC facilities, and new transmission lines reducing the need for capacity located within the Los Angeles Basin. Substantial changes to existing planning, procurement, and facility licensing processes would be required to implement this proposal. The SWRCB is considering this alternative approach.

Likely Impact on Summer Peak Resources and Reserve Margins

Any substantial delays in the construction of new fossil fuel facilities proposed in the Los Angeles Basin will impact the electricity supplies available to meet summer peak loads. **Figure 1** shows the geographic location of the existing OTC power plants impacted and those currently in the Energy Commission licensing process affected by the SCAQMD's Priority Reserve rule (and other associated rules favorable to repowering of existing generating facilities.)

Southern California Edison (SCE) is the major utility in the Los Angeles Basin, however many municipal utilities are also located there including: Los Angeles Department of Water and Power (LADWP), Burbank Water and Power, Glendale Water and Power (all are in the LADWP control area) Anaheim, Riverside, Pasadena and other smaller municipals.

Impact on Municipal Utilities

The court's SCAQMD ruling has limited impacts on Southern California municipal utilities in the California ISO control area. The City of Riverside is pursuing the 96 megawatts (MW) Riverside Energy Resource Center that requires only a limited amount of emission reduction credits through the regional offset market. In the California ISO control area, there are no permitted facilities "in reserve" that can be brought on-line without going through the Energy Commission's siting process. The rule impacts three other Southern California municipal utilities (Cities of Vernon, Anaheim, and Palmdale), but in a small way because (1) these utilities are largely resource adequate[5] (although the city of Anaheim, whose project is impacted by the ruling, will likely purchase capacity under contract for a share of their needs until the projects can be completed), (2) the total peak load for these entities grows by only 25 to 30 MW per

[5] *Progress Report on Resource Adequacy Among Publicly Owned Load-Serving Entities in California*, Staff Final Report, May 2007. CEC-200-2007-016-SF

year[6], and (3) much of this load growth is anticipated to be met with renewable resources added over the next five years to meet California's preferred resource policies. [7]

LADWP has three power plants totaling over 2,000 MW of capacity that use OTC, and apparently intends to repower most of the units in these plants. In securing air quality permits, LADWP faces the same challenges as any other entity within the SCAQMD's jurisdiction.

Impact on Southern California Edison

SCE is more severely impacted by the SCAQMD ruling since the amount of capacity assumed to retire in the SCE service area over the next several years is substantial (**Table 2.**[8]).

Table 2: SCE Assumed Retirements

Year	Retirements (MW)	Cumulative (MW)
2009	500	
2010	1,350	1,850
2011	1,200	3,050
2012	1,450	4,500
2013	850	5,350

These planning assumptions reflect the Energy Commission's *2005 IEPR* recommendation that the aging plants be retired (and/or repowered/replaced) by 2012 and the CPUC's direction to SCE that retirement be staggered over a longer period of time through 2018. In the following supply-demand analysis, staff is using the CPUC-approved retirement values because SCE used these values to procure new generation capacity over the five-year period.

The CPUC has authorized SCE to procure 3,200 MW of capacity to maintain service area reserve margins based on the retirement assumptions. Currently, SCE has contracted for 2,556 MW (summer peak dependable) of new generation on behalf of bundled and direct access

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[6] California Energy Demand 2008-2016, Staff Revised Forecast, November 2007. CEC 200-2007-015-SF2. LADWP grows roughly at a similar amount, but Glendale, Burbank and IID are excluded from consideration in this discussion as they lie outside the California ISO control area. The figures cited in this document do not include LADWP, which is resource adequate. Per its 2007 IEPR filing, LADWP has a 2008 peak capacity requirement, including reserves of 7147 MW and has 7294 MW under its control, almost all of which (7160 MW) is utility-owned generation. LADWP's current resource plan does not indicate an intention to acquire other than renewable resources or repower existing facilities until 2013-2014, at which time it may desire to repower selected units at Haynes and Scattergood.

[7] Electricity Analysis Office publicly owned utility renewable project news tracking file.

[8] None of the capacity assumed to retire in **Table 2** is specific, such as no facilities have announced an intention to retire.

customers. The SCAQMD ruling[9] threatens 1,757 MW of this capacity that had been expected to come on-line from 2010 to 2013.

Table 3: SCE Capacity Impacted by SCAQMD Rule

Year	Facility	Capacity (MW)	Cumulative (MW)
2010	Sentinel I	455	
2011	El Segundo Repower – Units 1&2	550	1,005
2012	Sentinel II	273	1,278
2013	Walnut Creek	479	1,757

The planning assumptions and planning reserve margin calculations for the Southern California region over the next five years using the CPUC procurement authorization assumptions are shown in **Table 4**. The Southern California portion of the California ISO control area has approximately 1,200 MW of capacity *more* than necessary to sustain a 15 percent reserve margin in 2009. Given construction of the 2,561 MW of capacity contracted for by SCE and other high probability Southern California additions that are not impacted by the SCAQMD ruling[10], *and assuming the retirement of 5,350 MW* by 2013 as described earlier, the 2013 planning reserve margin falls to about 11 percent or 1,116 MW. Clearly, this outcome would increase vulnerability to contingencies such as unusual outages.

The SCAQMD Priority Reserve ruling has a direct impact on the planning reserve margins in the Southern California area of the California ISO. When the 1,757 MW of capacity under contract to SCE and subject to the court ruling is retired in 2013, the planning reserve margin declines from the 11 percent requirement (**Table 4**) to about 5 percent (**Table 5**). This translates to a planning reserve deficit of nearly 2,900 MW in 2013 and would almost certainly lead to extensive outages, as the California ISO requires 6 percent margin for operating reserves.

[9] The nameplate capacity totals 1,910 MW in the table/legend contained in Figure 1. The lower value of 1,757 MW represents the summer peak dependable capacity used in load-resource tables and reserve margin estimation.

[10] 2009 - Inland Empire (713), 2010 - Otay Mesa (562), Blythe I (490), 2012 – Wellhead (49) & SDGE RFO (500)

Table 4: Southern California Planning Assumptions and Planning Reserve Margins (Includes SCE, SDG&E and California ISO Participating Municipals) Five Year Outlook including SCAQMD Power Purchase Agreements Affected by Ruling

Resource Adequacy Planning Conventions	2009	2010	2011	2012	2013
Existing Generation[1,2]	22,583	22,946	23,303	22,853	22,325
Retirements (Projected & Aging Plants)[3]	-500	-1,350	-1,200	-1,450	-850
SCE RPS (Projected@20% Capacity)[4]	150	200	200	100	150
High Probability CA Additions & PPAs	713	1,507	550	822	479
Net Import	10,100	10,100	10,100	10,100	10,100
Total Net Generation (MW)	33,046	33,403	32,953	32,425	32,204
1-in-2 Summer Temperature Demand (Average)	29,079	29,557	30,029	30,498	30,949
Demand Response (DR)[4]	200	330	490	640	760
Interruptible/Curtailable Programs	1,215	1,215	1,215	1,215	1,215
15% Planning Reserve Requirement	31,814	32,214	32,573	32,939	33,320
Planning Reserve Surplus/(Deficit)	**1,232**	**1,189**	**380**	**(514)**	**(1,116)**
Planning Reserve Margin	**19.5%**	**19.2%**	**16.3%**	**13.2%**	**11.1%**

[1] Based on California ISO 2009 Net Qualifying Capacity values.
[2] Includes renewable capacity already online.
[3] Include SCE projected retirements and 2005 IEPR recommended retirement of aging power plants with delayed schedule approved by CPUC.
[4] Based on SCE Resource Plan.

Impacts Using the Energy Commission 2005 IEPR Aging Power Plant Policy

The *2005 IEPR* policy on retiring aging power plants includes a larger amount and faster schedule than accepted by the CPUC in its 2006 long-term procurement plans (LTPP) decision. Using a retirement schedule that is consistent with the *2005 IEPR* policy recommendations for retiring aging power plants in the SCE and San Diego Gas & Electric (SDG&E) service territories, the planning reserve margin would fall to -3.5 percent when including the 1,757 MW that is threatened by the ruling and further decline to -9.5 percent without the new planned capacity. This is more than 7,000 MW short of meeting the California ISO-required 15 percent planning reserve requirement (**Figure 2**). Clearly, this outcome would not likely happen because emergency authority would be invoked to prevent one or more of the constraints implied by air quality rules on OTC mitigation.

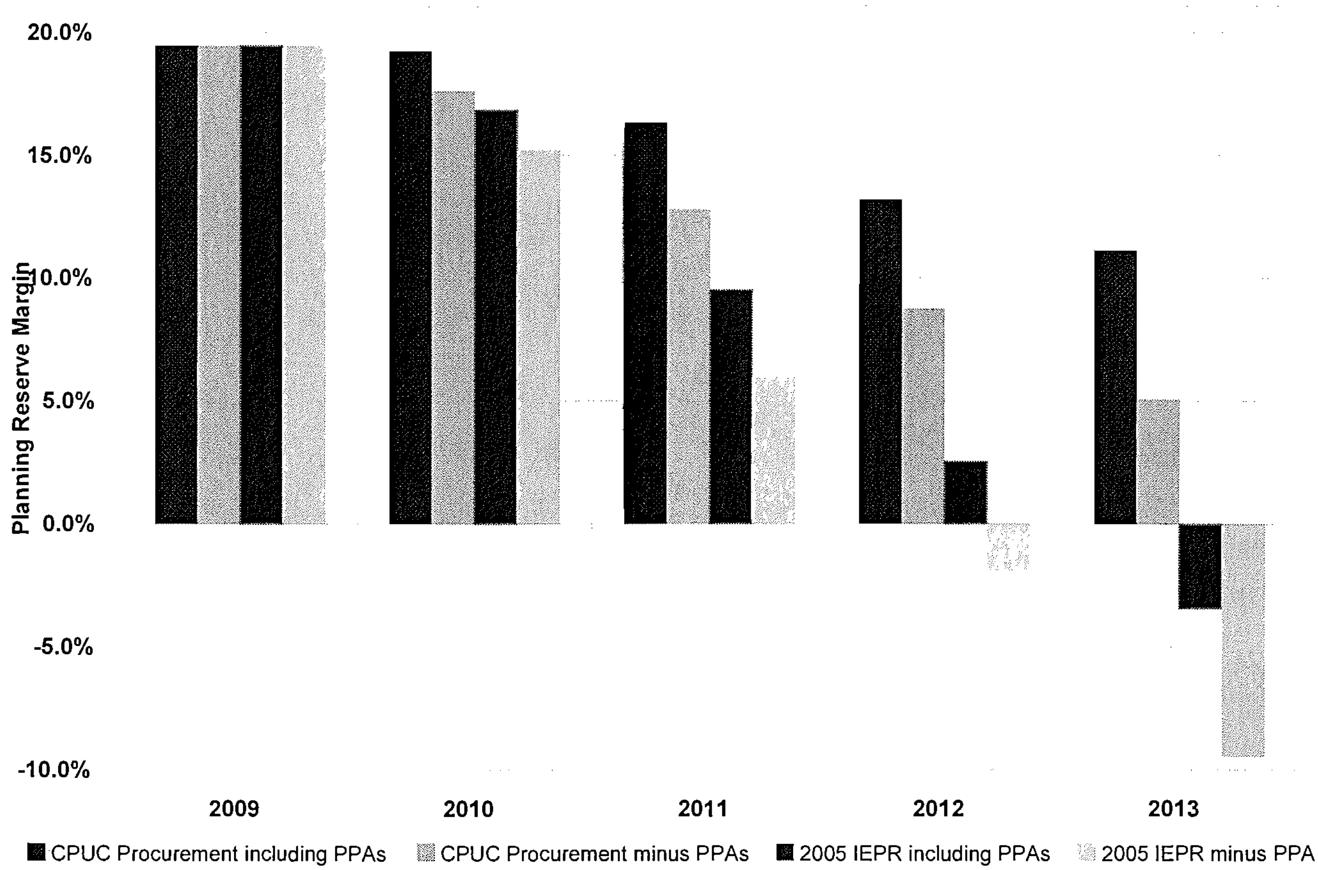
Table 5: SCAQMD Impacts on Southern California Planning Reserve Margins (Includes SCE, SDG&E and California ISO Participating Municipals) Five Year Outlook minus SCAQMD Power Purchase Agreements Affected by Ruling

Resource Adequacy Planning Conventions	2009	2010	2011	2012	2013
Existing Generation[1,2]	22,583	22,946	22,848	21,848	21,047
Retirements (Projected & Aging Plants)[3]	-500	-1,350	-1,200	-1,450	-850
SCE RPS (Projected@20% Capacity)[4]	150	200	200	100	150
High Probability CA Additions & PPAs	713	1,052	0	549	0
Imports carrying own reserves	6,100	6,100	6,100	6,100	6,100
Imports not carrying own reserves	4,000	4,000	4,000	4,000	4,000
Net Import	10,100	10,100	10,100	10,100	10,100
Total Net Generation (MW)	33,046	32,948	31,948	31,147	30,447
1-in-2 Summer Temperature Demand (Average)	29,079	29,557	30,029	30,498	30,949
Demand Response (DR)[4]	200	330	490	640	760
Interruptible/Curtailable Programs	1,215	1,215	1,215	1,215	1,215
Demand Response & Interruptible Load	1,415	1,545	1,705	1,855	1,975
15% Planning Reserve Requirement	31,814	32,214	32,573	32,939	33,320
Planning Reserve Surplus/(Deficit)	**1,232**	**734**	**(625)**	**(1,792)**	**(2,873)**
Planning Reserve Margin	**19.5%**	**17.6%**	**12.8%**	**8.7%**	**5.1%**

1 Based on California ISO 2009 Net Qualifying Capacity values.
2 Includes renewable capacity already online.
3 Include SCE projected retirements and 2005 IEPR recommended retirement of aging power plants as approved by CPUC.
4 Based on SCE Resource Plan.

The net result of delaying the contracted capacity affected by the SCAQMD ruling is that reserve margins dip below acceptable planning reserve margins starting as early as 2011 and worsen through 2013 under both the CPUC procurement authorization assumptions and the *2005 IEPR* policy (**Figure 2**). Assuming that there is no change in the air quality process, avoiding this situation may require delays in retiring an equivalent amount of aging capacity, thereby delaying efficiency gains, GHG emission reductions, and improvements to the marine environment.

Figure 2: Comparing Impact of Ruling on Southern California Planning Reserve Margins under Alternative Retirement Assumptions



There are five aging facilities for which retirement would most likely be deferred because of the impossibility of licensing enough replacement infrastructure by 2012 in the Los Angeles Basin local reliability area (**Table 6**)[11]. These plants are approximately one-half of the necessary local capacity in the Los Angeles Basin load pocket.

[11] *Local Capacity Requirements for 2009: Summary of Findings,* Catalin Micsa, California ISO, presented to the LCR Stakeholder meeting, March 4, 2008. Note that these values are for the California ISO and do not include LADWP capacity and needs, which includes aging plants at Haynes (1133 MW) and Scattergood (803 MW).

Table 6: California ISO Local Capacity Requirements and Possible Delayed Retirements

Area/Sub-Area	LA Basin	
Total Capacity	12,282 MW*	
LCR Capacity	10,225 MW*	
Aging Plants	Alamitos 1-6	1,950 MW
	El Segundo 3-4	670 MW
	Huntington Beach 1-2	430 MW
	Redondo Beach 1-4	1,310 MW
	Etiwanda 3-4	.640 MW
	Total	5,000 MW

Impact on Proposed Capacity Additions in the Los Angeles Basin

The consequence of the Superior Court rulings of July and November 2008 is that currently no new stationary source in the SCAQMD region requesting access to the Priority Reserve, including large, gas-fired power plants, can be permitted. Furthermore, access to the Priority Reserve for projects in down-wind air basins, which have proposed inter-basin trades because emission reduction credits for some criteria pollutants have not been available, are not possible.

The Energy Commission has licensed over 13,000 MW of thermal power plant capacity since 2003. While a few of these projects have been abandoned, others are either under construction or awaiting financial commitments such as utility long-term contracts to begin construction.

Only three power plants licensed by the Energy Commission are located in the Los Angeles Basin load pocket and could, if developed, allow retirement of some of the existing aging power plants. These are:

- Inland Empire (maximum capacity 800 MW) secured all its required emission reduction credits, including those from the Priority Reserve. The facility operated briefly during summer 2008, however it is currently inoperable due to a turbine failure. Unit 1 is expected to be in commercial operation before summer 2009, but Unit 2 is not expected to come on line until early 2010.

- The owner of the existing El Segundo power plant, NRG Energy, secured a license for repowering of Units 1 &2 (nameplate capacity of existing units is 350 MW; license was granted for a repowered facility with nameplate capacity of 630 MW) from the Energy Commission in 2005. In June 2007, NRG petitioned to amend its license so it could build a 560 MW facility. With the current change in facility size, NRG does not have sufficient emission reduction credits to move forward with construction of its El Segundo Repower project with a nameplate capacity of 560 MW, and the district is now (according to the court ruling) unable to issue NRG any credits for the project.

- Walnut Creek Energy Center (nameplate capacity 500 MW) received a permit from the Energy Commission in summer 2008 using the SCAQMD Priority Reserve credits. The facility is currently on hold with construction to start in late 2009 pending resolution of the Priority Reserve credit issues. If these credits are invalid, then no other sources are available to allow this power plant to satisfy its permit conditions and be constructed.

There are a number of power plants currently in the licensing process at the Energy Commission that could, if permitted and brought on-line, allow more aging power plant retirement. CPV Sentinel is the most likely of these since it has a power purchase agreement with SCE, which other power plant applications in the Energy Commission licensing process do not have. Further, Sentinel is a "peaker" and would have lower levels of emissions than a baseload power plant of equal capacity. CPV filed an application with the Energy Commission in June 2007 for its Sentinel Peaker (nameplate capacity 850 MW) project, proposed in Desert Hot Springs, north of Palm Springs. This location is just within the eastern portion of the Los Angeles Basin load pocket. CPV has applied to the SCAQMD for use of Priority Reserve credits to meet its obligation to mitigate PM10 emissions; however, this issue is still unresolved.

Two other projects lie outside the Los Angeles Basin, but still are dependent on using Priority Reserve credits to go forward. The Energy Commission has licensed one and the other is in the review process.

- In July 2008, the Energy Commission licensed the Victorville 2 gas/solar hybrid project (nameplate capacity 563 MW) in the Mojave Desert Air Quality Management District, adjacent to the South Coast air basin. Victorville used an inter-basin trading approach that depended on Priority Reserve credits. If the owners are not able to find acceptable replacement credits to use in the Mojave District, they may not be able to construct and operate. The Victorville 2 project currently has no power purchase agreement.

- The Palmdale project (nameplate capacity 617 MW), currently under Energy Commission review, is also outside of the Los Angeles Basin. The Status of Projects (**Attachment 1**) provides detail on the Palmdale project, and the other projects proposed within the Los Angeles Basin, currently under Energy Commission review.

Overall, there are eight power plants currently in the Energy Commission licensing process affected by the SCAQMD Priority Reserve problem. (See **Figure 1** and **Attachment 1**.) New power plant development will be extremely limited unless the lack of available emission credits is resolved. In an environment where new power plants must be developed to replace those that will retire by the OTC rule, it is important to have sufficient lead-time to allow this replacement process to happen in a scheduled manner to assure continued reliability. With limited or no emission credits, the inability to site new or repowered generation in Southern California could delay any effective implementation of the OTC policy because of a major risk to reliability, despite the SWRCB's explicit goal to avoid such threats.[12]

Analysis of Capacity to Satisfy Local Capacity Requirements in Los Angeles Basin Load Pocket

This section summarizes an analysis of the air quality credit/OTC mitigation conflict on local capacity requirements in the Los Angeles Basin portion of the California ISO control area. [This does not address parallel requirements of the Los Angeles Department of Water & Power control area.] The Los Angeles Basin is contained within the air shed administered by the SCAQMD. The SCAQMD's jurisdiction also extends outside the South Coast air basin to include the Palm Springs region within Riverside County (**Figure 1**).

As discussed, the Los Angeles Basin is heavily reliant on aging coastal power plants that use OTC. The SWRCB has proposed the phase-out of this cooling method, effectively requiring the closure or replacement of these Los Angeles Basin facilities. The SWRCB's proposed policy would require such extensive mitigation that most affected power plants are expected to retire rather than reinvest in control technologies necessary to meet the new requirements. With enough lead-time, however these retirements (and the electricity generated from them) could be replaced by new fossil fuel power plants that do not use OTC technologies.

The California ISO considers the Los Angeles Basin a "load pocket," defined as a local area, bounded by transmission equipment including distribution circuits, and is connected to the entire California ISO transmission grid through interconnections with limited import capacity. This means that generation internal to the load pocket must be capable of supporting load under extreme conditions to assure reliability. The California ISO determines local capacity requirements (LCR) on a year-ahead basis for each load pocket using specific criteria related to hot summer temperatures, resources in the load pocket, maximum imports, and contingency conditions.

- All load-serving entities (LSEs) in the California ISO control area are required to secure generating resources from within the load pocket based on their share of peak demand in the load pocket.[13] This process is coordinated through the resource adequacy program of the

[12] Tam Doduc, Board Chair, SWRCB. Oral comments from the May 13, 2008 public meeting to review the March 2008 OTC Policy report.

[13] The CPUC implements the California ISO LCR study in a way that allows LSEs to satisfy load pocket requirements in certain groupings rather than separately for each load pocket. Since these groupings are entirely in the inland areas of the PG&E Transmission Access Charge area, this simplification does not affect the analyses of load pockets where OTC power plants are located.

CPUC and the California ISO. LSEs are required to make these resources available to the California ISO for dispatch through contractual obligations.

A simple spreadsheet model was developed using data from prior California ISO and Energy Commission studies to evaluate whether local capacity requirements can be satisfied in future years as load grows, power plants are retired, and other power plants are added. This model does not *predict* future outcomes; however, it does allow assumptions about possible outcomes to be evaluated, focusing specifically on whether LCR values are satisfied.

Two target years, 2012 and 2015, are evaluated assuming different amounts of generation development (**Figure 3**). For 2012, the Inland Empire power plant was assumed to become operational. For 2015, two alternative assumptions about power plant development were made: (1) only the El Segundo power plant would be completed and operational, (2) the El Segundo and Walnut Creek Energy Center facilities would be constructed and in operation.

The model was run for both target years with different levels of OTC capacity retired to determine when reliability criteria in the Los Angeles Basin would no longer be satisfied. For purposes of this analysis, a surplus capacity larger than zero is considered acceptable. Having values close to zero; however, might create other market power concerns and cause capacity prices to be higher than if greater surpluses were available.

Results of the model runs, represented by the 2012 line and 2015 line (only the addition of El Segundo) on **Figure 3**, are nearly equal and can be interpreted as the addition of El Segundo is required to offset load growth between 2012 and 2015; otherwise, less OTC capacity could be retired. The alternative 2015 line (all three power plants operational) allows the greatest amount of OTC capacity to be retired without threatening local reliability.

Figure 4 provides the results from an investigation of transmission development. In this case, only Inland Empire was assumed to be developed, which implies that the SCAQMD Priority Reserve credits never become available and the El Segundo and Walnut Creek Energy Center plants are never developed.

The California ISO has published limited information about the extent to which transmission development can reduce LCR values in the various load pockets. In the case of the Los Angeles Basin, the California ISO has indicated that four transmission projects can reduce LCR requirements.[14] Since these transmission developments take extended timeframes to develop, they are not assumed to come on-line until 2015.

The 2012 line in **Figure 4** matches that from **Figure 3** since Inland Empire is assumed to be operational. Unlike the analyses portrayed in **Figure 3**; however, in this alternative analysis of transmission upgrades, Inland remains the only power plant licensed and constructed. The initial 2015 line adds no additional generation development and no transmission line expansion. Load growth shifts this 2015 line to the left, meaning that less OTC can be retired before LCR

[14] California ISO, Old Thermal Generation, Phase 1 Report (2008-2012 Study Results), March 2008, http://www.caiso.com/1f80/1f80a4a5568f0.pdf

capacity diminishes to threatening levels. The second 2015 line assumes that one of the four transmission lines is developed. This reduces the minimum LCR need somewhat, and allows greater OTC capacity to be retired. So the second 2015 line shifts to the right. However, even this transmission development is not enough to allow all OTC capacity to be retired. Even more transmission development would be needed to completely replace OTC capacity through a combination of new in-basin power plant capacity and new transmission.

This analysis of the local reliability consequences of various assumed power plant or transmission line developments reveals how these factors limit the amount of OTC capacity that can retire. With limited new power plant development, only about one-third of the OTC retirements of those that would likely happen if the SWRCB's proposed OTC mitigation policy were adopted as proposed in March 2008 could be allowed. System reliability would otherwise degrade below acceptable levels. Similarly, transmission line upgrades could permit some OTC-mitigation induced retirement without restoring the Priority Reserve rule. Greater power plant development (assuming restoration of Priority Reserve, or its functional equivalent) would allow greater retirements and improved OTC mitigation. It is also likely that a larger number of transmission line upgrades would also have this effect.

Finally, either the focused analysis of the Los Angeles Basin load pocket or the broader analysis of the South of Path 26 region (Path 26 is a main transmission line connecting Northern and Southern California) could identify constraints on retirement to satisfy reliability requirements. Both methods of analysis are important to full consideration of reliability and resource adequacy.

Conclusion

The Superior Court ruling making the SCAQMD's Priority Reserve Rule invalid will constrain the amount of OTC capacity that can be retired in this area and could jeopardize local electric reliability. Assuming only a single power plant that has credits will become operational (Inland Empire), OTC retirement is limited to about 1,600 MW in 2012 and less in 2015. This is about one third of the capacity scheduled for compliance by 2015 assuming the SWRCB's March 2008 version of OTC policy is implemented without change. With development of all three power plants in the Los Angeles Basin that qualify as LCR capacity, more OTC capacity can be retired, perhaps up to 2,700 MW by 2015. With no new plants beyond Inland Empire developed, significant new transmission infrastructure is necessary to allow substantial amounts of OTC capacity to be retired.[15] Even with one of the proposed transmission projects, this only allows about 2,500 MW by 2015.

[15] This analysis only examines local capacity requirements in the Los Angeles Basin. A comparable analysis of other load pockets is needed to determine whether these have conflicts with OTC mitigation-induced retirements. However, no region of the state has such severe problems permitting new power plants, as does Southern California after the priority Reserve court decision.

Clearly, there is a conflict between OTC compliance, as scheduled by the SWRCB in their March 2008 proposed policy and the apparent inability to construct and operate new power plants as a result of the court decision overturning the SCAQMD's Priority Reserve rule[16]. To assure system reliability, some mechanism for resolving this conflict must be developed and implemented by all stakeholders and decision-makers in a timely manner.

The energy agencies (Energy Commission, CPUC, and California ISO) have developed and submitted to the SWRCB an alternative implementation proposal that respects the SWRCB's desire to significantly reduce biologic harm from OTC operations, while satisfying the societal need for a reliable electricity system. Rather than requiring OTC mitigation on a fixed schedule, the energy agencies propose that retiring existing OTC facilities be linked to the developing of replacement facilities. These facilities might be a repowered facility at an existing OTC location using a cooling technology other than OTC, a new power plant located elsewhere in Southern California, or new transmission lines within Southern California that reduce the amount of capacity required to be located within the Los Angeles Basin load pocket. The SWRCB is currently considering this proposal. If the basic approach is accepted, then more detailed development of changes to the planning, procurement and permitting processes of the three energy agencies will be needed to put this proposal into effect.

[16] The Energy Commission staff believes that SWRCB's proposed OTC mitigation will induce retirements not replacements of the water intake structures with alternative cooling systems.

Figure 3: Surplus LCR Capacity as Function of Fossil OTC Retirements and Licensed Project Development (Los Angeles Basin Load Pocket)

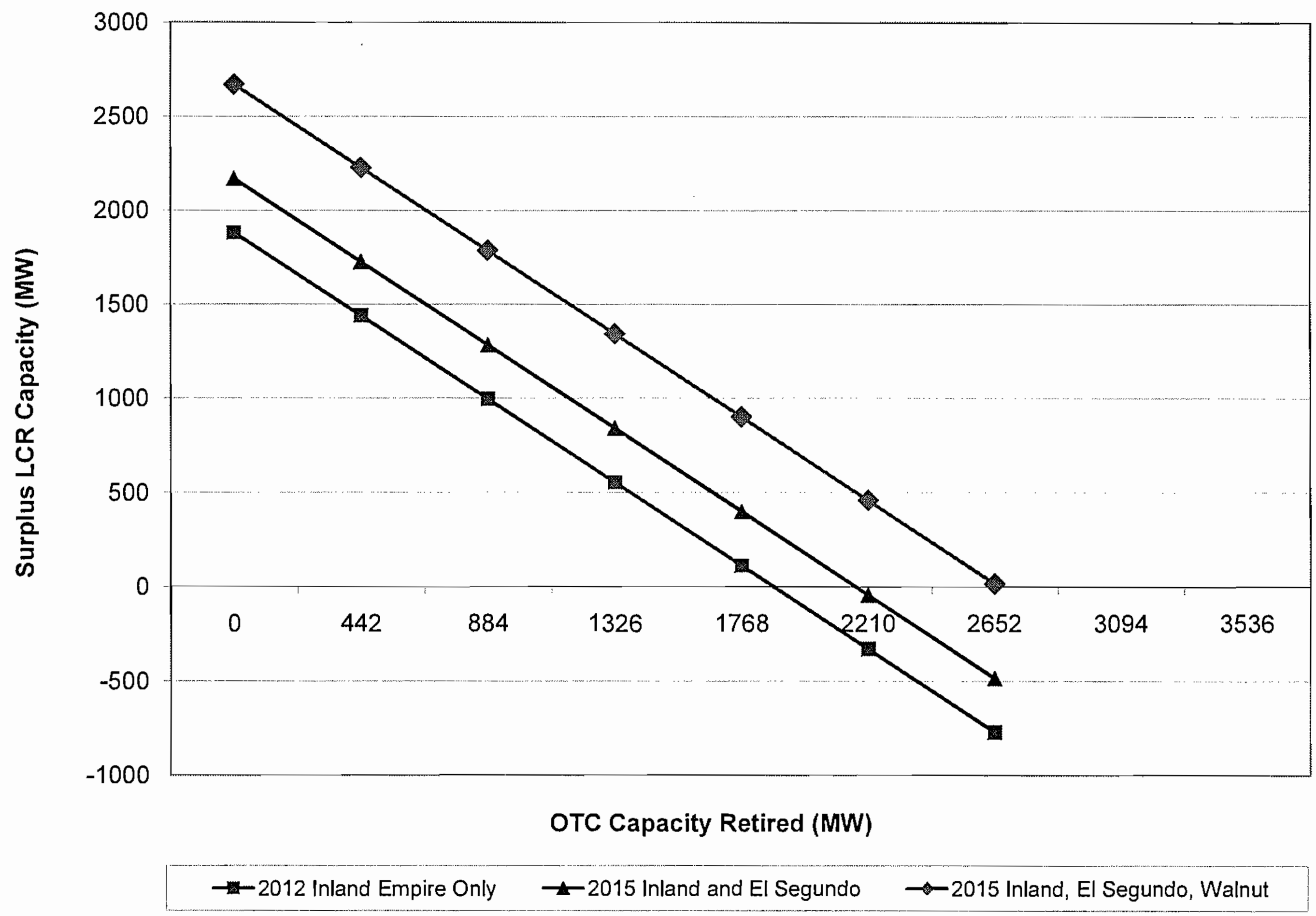
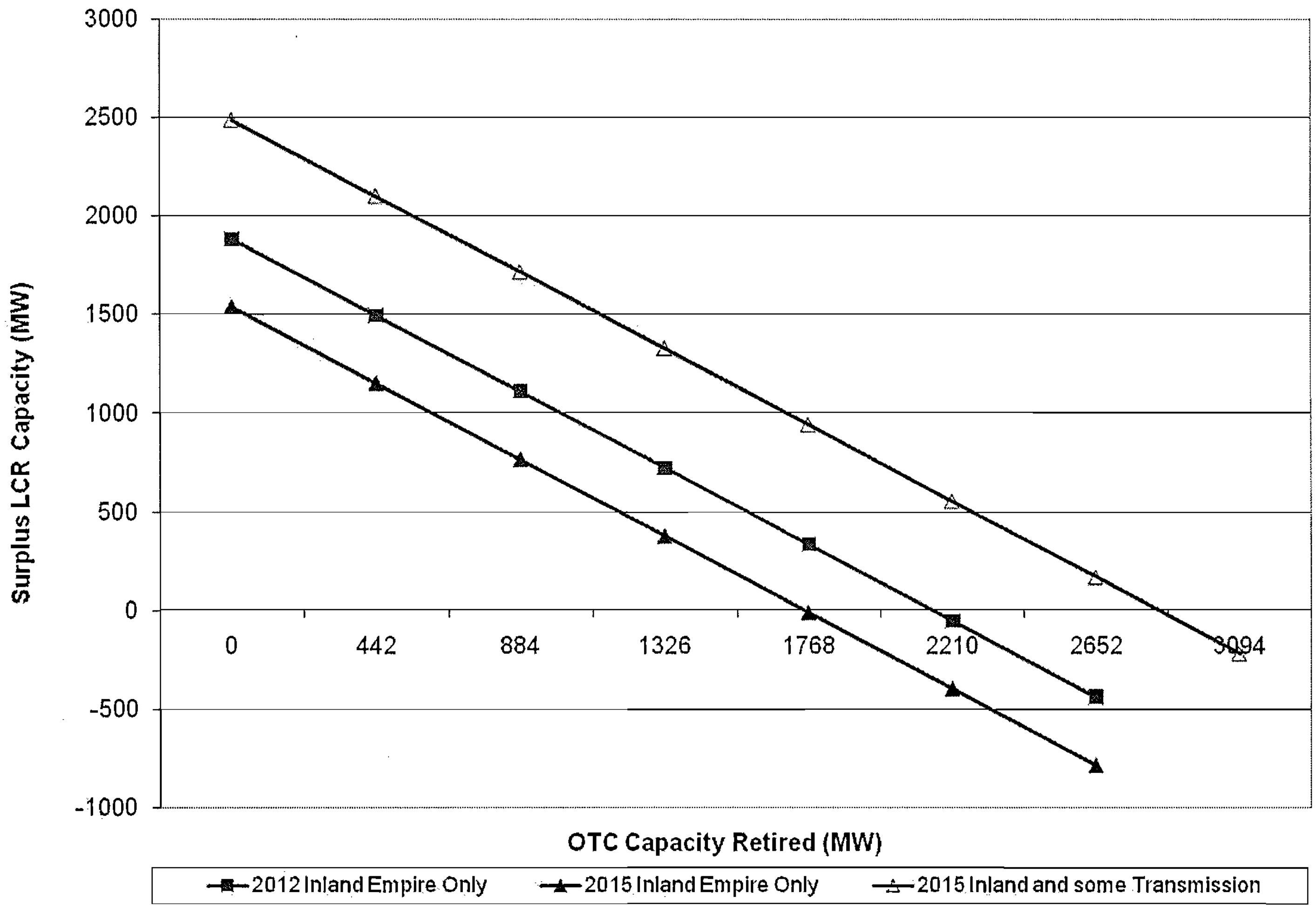


Figure 4: Surplus LCR Capacity as a Function of OTC Retirements and Transmission Development (Los Angeles Basin Load Pocket)



ATTACHMENT 1: CEC-Jurisdictional Power Plants Affected by Absence of Emission Reduction Credits in SCAQMD Air Shed

Project Name/Docket #	Staff Analysis Publication Date	MW (nominal)	Power Purchase Agreement or Muni?	Substation	Local Capacity Requirement Area
Canyon Power Plant (07-AFC-9)	PSA* date undetermined due to no PDOC* from SCAQMD	200	Muni	Vermont/Dowling – Yorba 69 kV (Lewis 230 kV/69kV Substation)****	LA Basin
CPV Sentinel Energy Project (07-AFC-3)	7/31/2008	850	PPA w/ SCE	Devers 203 kV Substation	La Basin
San Gabriel Generating Station (07-AFC-2)	3/12/08 PDOC; PSA date undetermined pending resolution of Priority Reserve issues	656	No	Rancho Vista Substation	LA Basin - Eastern
Southeast Regional Energy Center (Vernon) (06-AFC-4)	PSA date undetermined due to no PDOC from SCAQMD	943	Muni***	Laguna Bell Substation	LA Basin -Western/Barre
AES Highgrove Project (06-AFC-2)	PSA date is undetermined due to no PDOC from SCAQMD	300	No	Highgrove Substation	LA/Eastern
Sun Valley (05-AFC-3)	FDOC received 7/14/08 FSA date undetermined pending resolution of Pr. Reserve issues	500	No	Valley Substation	LA Basin - Eastern
Walnut Creek Energy Park (05-AFC-2)	FSA 12/29/2006; licensed 2/27/08	500	PPA w/ SCE	Walnut Substation	LA Basin -Western/Barre
El Segundo Repower (00-AFC-14C) Amendment	SA published 6/12/2008	560	PPA w/ SCE	El Segundo Substation	LA Basin -Western/Barre
SUBTOTAL		4509			
(City of) Victorville 2 Hybrid Power Project (07-AFC-1)**	FSA 11/21/2007; licensed 7/16/08	563	Muni***	Victor Substation	None
(City of) Palmdale Hybrid Power Plant Project (08-AFC-9)	PSA date undetermined pending PDOC and resolution of misc. issues	570	Muni***	Vincent Substation	None
SUBTOTAL		1133			
TOTAL		5642			

Notes:
*PSA – Preliminary Staff Assessment of Application For Certification (AFC) PDOC – air district's Preliminary Determination of Compliance SA – Staff Analysis (of Amendment).
FSA – Final Staff Assessment (AFC).
**Possible construction start date in late Spring 2009.
*** Capacity in excess of municipal existing load and load growth so owner will market remainder of power like merchant facility.
**** The City of Anaheim municipal transmission system interconnects with SCE/California ISO system at the Lewis 230/69 kV Substation.

ATTACHMENT 2

Background on South Coast Air Quality Management District Rules

SCAQMD New Source Review and Emission Offsets

The SCAQMD new source review (NSR) rules require that new major sources of the criteria air pollutant emissions be offset (Rule 1303(b)(2)) at a ratio of 1.2 to 1 (that is, for one pound of pollutant emitted, 1.2 pounds must be offset). This offset is achieved by one of two methods: emission reduction credits or short-term credits (STCs).

Emission reduction credits may be created by the reduction or elimination of emissions from an existing source (Rule 1309 (a),(b)) or by allocations from the Priority Reserve (Rule 1309.1 et al). Rule 1309 (a),(b) emission reduction credits (ERCs) are the source of the "free-market" credits traded generally in the SCAQMD. The Priority Reserve credits (PRCs) have traditionally been used for essential public services (such as sewage treatment facilities) or research operations (limited to two years) and innovative technology that can lower emissions below that required by best available control technology (BACT, Rule 1303 (a)). The PRCs are supplied through the District Account, which is populated by a variety of emission reductions; most predominantly from "orphaned shutdowns" which are small (less than four tons/year) emission sources that do not apply for an emission reduction credit when they cease operation. ERCs and PRCs are the most prevalent type of offset used in the SCAQMD to date.

There are three distinct types of short-term credits (STCs) permitted in the SCAQMD rules and regulations: short-term emission reduction credits (STERCs), mobile source emission reduction credits (MSERCs) and area source emission reduction credits (ASERCs). STERCs are created from existing ERCs, which are divided, in part or in whole, for a period of no more than seven years (thereafter they become permanently divided). MSERCs are governed by SCAQMD Regulation XVI, and include sources such as the voluntary repair of on-road heavy polluting vehicles, vehicle scraping, clean vehicle programs, truck stop electrification, clean lawn and garden equipment programs and clean diesel marine vessel programs. ASERCs are governed by SCAQMD Rule 2506 (restricted to NO_x and SO_x credits only) and consist of the turnover of non-mobile emitting sources within the SCAQMD, which are not subject to local, or state permitting or registration. STCs must be used within the same year they were actually created (Rule 1303 (b)(2)(B)). For this reason, no power project that proposes to use STCs as the main source of offsets has been successful in attaining financial backing.

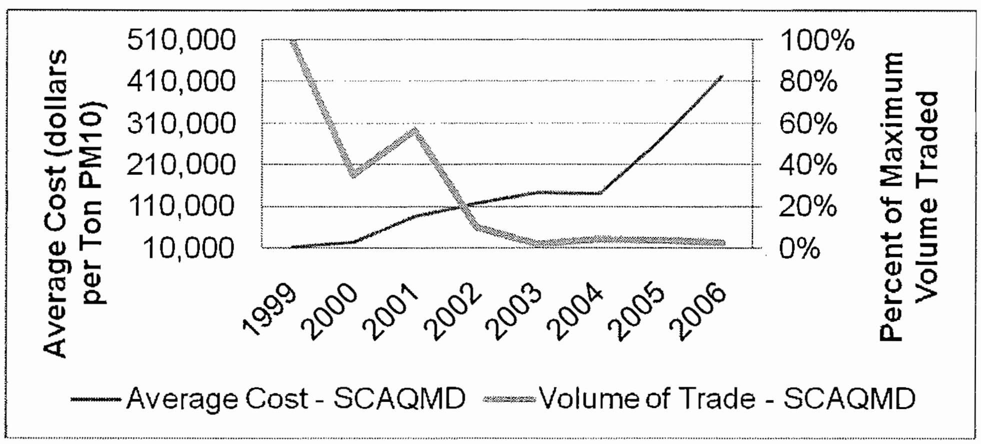
SCAQMD Exemptions to Offsets

Some exemptions to the SCAQMD NSR offset requirements for all or part of the offset liability of a new or modified emission source (Rule 1304) are possible. For example, if a new or modified project emits less than four tons/year of oxides of nitrogen (NOx), oxides of sulfur (SOx), volatile organic compounds (VOC) or particulate matter less than ten microns in diameter (PM10), then the project proponent is exempted from the offset requirements of Rule 1303 (Rule 1304 (d)(2)(B)). However, the SCAQMD must offset all pollutants exempted under Rule 1304 (2007 South Coast portion of the California State Implementation Plan or SIP). The SCAQMD complies with this SIP requirement by drawing emission reduction credits from the District Account in an annual NSR Balance Report. Other exemptions in Rule 1304 generally include in-kind replacements, portable equipment, emergency equipment, facility relocation, resource recovery facilities, regulatory compliance requirements, and electric utility boiler replacements.

Limited PM10 Offset Availability and Priority Reserve Rule Development

In 1998, the SCAQMD learned that the price and volume of offset market trading for PM10 ERCs were becoming unstable. The cost of PM10 ERCs increased to be prohibitively expensive which led to a shrinking number of market transactions (see **Figure 2-1**). The last major power plant project to use only PM10 ERCs was the Mountain View Power Project, a 1,000 MW natural gas-fired combustion turbine power plant approved by the Energy Commission in March 2001. Mountain View used 22 individual PM10 ERCs (5-6 are typical) plus inter-pollutant trading of SOx for PM10 (2:1 ratio) to satisfy the NSR PM10 offset requirements of 1,030 lbs/day.

Figure 2-1: Average Annual Cost of PM10 Emission Reduction Credits South Coast Air Quality Management District1999-2006



Source: Emission Reduction Offsets Transaction Cost Summary Reports 1999-2006, California Air Resources Board

In April 2001, the SCAQMD approved amendments, after more than a year in process, to Rule 1309.1 Priority Reserve to allow temporary access to the PRCs by qualifying Electric Generating Facilities (EGFs), including new power plant proponents. The access was granted to EGFs that performed a "good faith effort" to purchase PM10 ERCs, were deemed data complete in 2000, 2001, 2002, or 2003, and had a contract to sell at least 50 percent of their power to the California grid, among other things. Each EGF was required to show proof of their good faith efforts being made to the SCAQMD by contacting ERC holders. The SCAQMD produced periodic snapshot reports of what they termed "available credits," which meant those ERCs not secured by permits, and thus, available for sale. **Table 2-1** shows a portion of one such snapshot report for September 2008. The table only includes the PM10 ERCs for the 19 largest holders (of 74 total individual holders) and the total ERCs available in September 2008. There are enough available PM10 ERCs to permit approximately two 500 MW peaking power plants if credits from all 74 ERC holders could be purchased (not just the 19 shown). Of the 19 holders shown, the two largest are petroleum chemical based companies: BP West and Ultramar.

Table 2-1: South Coast Air Quality Management District Summary of Active PM10 Emission Reduction Credits September 2008

COMPANY NAME	AVAILABLE PM10 ERCS (LBS/DAY)
BP WEST COAST PROD.LLC BP CARSON REF.	128
ULTRAMAR INC	122
LA CITY, DWP HAYNES GENERATING STATION	31
CHEVRON PRODUCTS CO.	24
UCLA	20
EQUILON ENTERPRISES, LLC	20
CONOCOPHILLIPS COMPANY	19
ULTRAMAR INC (NSR USE ONLY)	18
AERA ENERGY LLC	18
RIVERSIDE CEMENT CO (EIS USE)	17
LA CITY, DWP	15
OWENS CORNING ROOFING AND ASPHALT, LLC	13
SES TERMINAL LLC	12
CANTOR FITZGERALD BROKERAGE, LP	12
US BORAX INC	10
US GOVT, AF DEPT, MARCH AIR RESERVE BASE	10
US GOVT, NAVY DEPT LB SHIPYARD	10
BARRY CONTROLS	10
3M COMPANY	10
TOTAL AVAILABLE PM10 ERCs	**808**

Source: SCAQMD September 2008 Current Active ERC List

In 2001, qualifying EGFs could purchase PM10 PRCs for $25,000 per lbs/day, which translated into approximately $11.5 million for a 500 MW power project (approximately 460 lbs/day of PM10). The projects under the Commission jurisdiction that qualified were Inland Empire (670 MW), El Segundo (630 MW) and Malburg Generation Station (134 MW). Only Malburg was able to find and purchase at least some PM10 ERCs (approximately 6 lbs/day). Inland Empire is currently in construction, Malburg is operational, and El Segundo has been disqualified as an EGF because the applicant filed a major amendment to the project, which proposes to change the turbine manufacturer, the ultimate capacity and eliminate the once through cooling system.

The El Segundo case is unusual in that it used both the Priority Reserve (Rule 1309.1) and the Utility Boiler Exemption (Rule 1304 (a)(2)) to satisfy the SCAQMD NSR offset requirements. The 1304(a)(2) exemption was granted via the replacement of an electric generating utility boiler with combustion turbines of the same or lower capacity. However, since the El Segundo boilers (Units 1 and 2) were 340 MW total and the new combustion turbines were 630 MW, the project proponent (NRG) had to offset the additional 46 percent of their project emissions. For PM10, NRG chose to use the Priority Reserve. Since the original boilers did not produce as much PM10 as the proposed combustion turbines (about a quarter of the proposed), the SCAQMD used the emission reductions of the boiler shutdowns and emission credits from the District Account in addition to the PRCs purchase by NRG to comply with the NSR offset requirements for the project. Thus, approximately three-quarters of the offsets for the El Segundo project would have come from the District Account (via the NSR Balance of 1304 Exemptions and the PRCs purchased by NRG).

After the 2003 window had shut on the Priority Reserve, the SCAQMD found significant interest from power plant developers in re-opening it. Given the need for power development identified in the *2005 IEPR*, the SCAQMD began the process of amending Rule 1309.1, again. However, the U.S. Environmental Protection Agency (EPA) took a more active role in the process. As a result, the SCAQMD agreed to eliminate a large portion of the credits remaining in the District Account given a lack of documentation (94 percent of PM10 credits and 80 percent of all pollutant credits in total). The remaining credits were documented as real, quantifiable, permanent, and verifiable by the SCAQMD, which was accepted by the EPA.

Additionally, the EPA proposed a reporting requirement to make clear the source and disposition of all credits and debits to the District Account. The SCAQMD agreed and drafted a rule for adoption (Rule 1315). Rule 1315 also enabled the SCAQMD to replenish the District Account to some degree by allowing them to "harvest" as needed the 0.2 of the 1.2:1 offset ratio imposed by Rule 1303 on all offsets surrendered. With Rule 1315 in place and the District Account ratified by EPA, the SCAQMD proposed the second amendment to Rule 1309.1 (Priority Reserve) to allow limited use of PRCs by qualifying EGFs.

However, at this point several community groups and environmental activists had become aware of the proposed amendment and intervened in the process. The involvement of these groups forced the SCAQMD into a long public debate (approximately two years) to develop and redevelop compromises in an attempt to appease the parties involved. This finally culminated in an amendment that was ratified by the SCAQMD Governing Board in August 2007.

The 2007 amendment placed far more requirements on EGFs to qualify for access to the PRCs than in the 2001 amendment. The new amendment defined three new zones (1, 2, and 3) based on the average annual ambient PM2.5 concentration and defined an Environmental Justice Area (EJA) based on the percentage of population below the poverty level. The requirements (shown in **Table 2-1**) on an EGF to qualify became more restrictive as the number of zone facilities increased, or if they were located in an EJA. These requirements are far more restrictive than any air district has ever imposed on any class of pollution emitting devices. However, qualifying EGFs could purchase PM10 PRCs at a cost of $92,000 per lbs/day, which translates into a cost of approximately $42.32 million for a 500 MW power plant; a 370 percent increase in cost compared to the 2001 amendment. Finally, the Governing Board ordered the SCAQMD to spend the fees raised "as close as possible" to the project site.

Immediately following the Board's approval of the 2007 amendment for Rule 1309.1, the intervening community and environmental groups filed a lawsuit in the California Superior Court to enjoin the Board's action and set aside the amended rule. In July 2008, the court found for the plaintiff and suspended the amended Rule 1309.1 and Rule 1315. The court stated that the SCAQMD had failed to perform an adequate CEQA analysis to evaluate the potential impacts of all twelve power plants that proposed to make use of the PRCs under the amended rules.

Following the ruling in the state trial court, the litigants brought a separate action in federal court asking the court to find that there are no remaining ERCs in the District Account. That action is in the pre-trial stage, but the litigants contend that the District Account no longer has any credits for the purposes of complying with NSR offset requirements in the SCAQMD. They prefer to hold harmless those entities, which have used the PRCs in good faith, but rather put the burden on the SCAQMD to find (or new programs to create) new offsets.

Current Status

With the remaining credits (and possibly more) in the District Account in jeopardy and the setting aside of Rule 1315; the SCAQMD might not be able to comply with the SIP requirement to produce an NSR Balance Report and thus offset any new emission sources using Rule 1304 Exemptions or Rule 1309.1 Priority Reserve. Therefore, on January 9, 2009, the SCAQMD issued a moratorium on the issuance of all new Permits to Construct or Operate that relied on the District Account to satisfy NSR requirements. This affects any facilities qualifying under the current 1309.1 (landfills, sewage treatment plants, hospitals, etc) as well as any facilities qualifying under Rule 1304 (auto body shops, dry cleaners, printers, gas stations, small power plants, etc). The SCAQMD has appealed the state court decision setting aside Rules 1309.1 and 1315, and has launched a rulemaking to re-instate Rules 1309.1 and 1315, but without the power plant access provision in Rule 1309.1. The district believes that restoring the ability to issue permits to the non-power plant facilities qualifying for these rules as essential to the economic activity of the Los Angeles region. The rulemaking is expected to take nine to twelve months.

Assuming this SCAQMD course of action is successful, sometime in 2010 there will be two options for power plant applicants: (1) qualify for an exemption under Rule 1304 and hope that needed air quality credits can be obtained from the District Account, or (2) procure ERCs on the open market. Access to Rule 1304 is limited to existing power plants qualifying for the repowering exemption, and therefore is not available to new "greenfield" power plants. Until Rule 1315 is restored, allowing access to Rule 1304 in conjunction with valid credits in the District Account, the only option for power plants is securing ERCs on the open market for whatever price they can negotiate, thus avoiding the District Account all together. The SCAQMD estimates the current price as $148,000 per pound/day; therefore, for a 500 MW peaking power plant (approximately 460 lbs/day of PM10) implies approximately 70 million dollars of additional capital investment added to the direct cost of the plant itself.[17] These prices correspond to an extreme shortage of available ERCs. The owners of these ERCs may have no interest in selling such ERCs if they have their own internal industrial facility expansion plans.

[17] Mohsen Nazemi, Deputy Executive Officer of SCAQMD, personal communication, Feb. 10, 2009.

Table 2-2: Qualification Requirements for Electricity Generating Facilities Under Rule 1309.1 Priority Reserve, 2007 Amendment

Performance Requirements	Zone 1	Zone 2 or <=500MW and in either Zone 3 or EJA	>500MW and in either Zone 3 or EJA
Cancer Risk	10 in 1,000,000	1 in 1,000,000	0.5 in 1,000,000
Non-Cancer Risk	1	0.5	0.1
Cancer Burden	0.5	0.1	0.05
Rate of PM10 Emissions	NA	<= 0.06 lbs/MW-hr	<= 0.035 lbs/MW-hr
Rate of NO_x Emissions	NA	<= 0.08 lbs/MW-hr	<= 0.05 lbs/MW-hr
Total Combined PM10 Hourly Emissions	NA	NA	<= 30 lbs/hr
24-hour Impact of PM10 Emissions from New or Modified EGFs	<= 2.5 ug/m^3 per gas turbine	<= 5 ug/m^3 for total combined gas turbines	<= 2.5 ug/m^3 for total combined gas turbines
Annual Impact of PM10 Emissions from New or Modified EGFs	<= 1.0 ug/m^3 per gas turbine	<= 0.75 ug/m^3 for total combined gas turbines	<= 0.5 ug/m^3 for total combined gas turbines
Yearly Maximum Hours of Operation – simple cycle only Yearly Maximum Hours of Operation – simple cycle only	NA	4,000 hours or less	3,000 hours or less
Required of all projects in all zones	Long-term contract (1 year) with the State of California to sell at least 50% of the power generated.		
	Demonstrate that renewable energy is not a viable option at the proposed site (up to 10% of proposed capacity).		

C. Court Decisions

1. *Entergy U.S.* Supreme Court Decision

Syllabus

NOTE: Where it is feasible, a syllabus (headnote) will be released, as is being done in connection with this case, at the time the opinion is issued. The syllabus constitutes no part of the opinion of the Court but has been prepared by the Reporter of Decisions for the convenience of the reader. See *United States* v. *Detroit Timber & Lumber Co.,* 200 U. S. 321, 337.

SUPREME COURT OF THE UNITED STATES

Syllabus

ENTERGY CORP. *v.* RIVERKEEPER, INC., ET AL.

CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE SECOND CIRCUIT

No. 07–588. Argued December 2, 2008—Decided April 1, 2009*

Petitioners' powerplants have "cooling water intake structures" that threaten the environment by squashing against intake screens ("impingement") or suctioning into the cooling system ("entrainment") aquatic organisms from the water sources tapped to cool the plants. Thus, the facilities are subject to regulation under the Clean Water Act, which mandates that "[a]ny standard established pursuant to section 1311 . . . or section 1316 . . . and applicable to a point source shall require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." 33 U. S. C. §1326(b). Sections 1311 and 1316, in turn, employ a variety of "best technology" standards to regulate effluent discharge into the Nation's waters. The Environmental Protection Agency (EPA) promulgated the §1326(b) regulations at issue after nearly three decades of making the "best technology available" determination on a case-by-case basis. Its "Phase I" regulations govern new cooling water intake structures, while the "Phase II" rules at issue apply to certain large existing facilities. In the latter rules, the EPA set "national performance standards," requiring most Phase II facilities to reduce "impingement mortality for [aquatic organisms] by 80 to 95 percent from the calculation baseline," and requiring a subset of facilities to reduce entrainment of such organisms by "60 to 90 percent from [that] baseline." 40 CFR §125.94(b)(1), (2). However, the EPA expressly declined to mandate closed-cycle cooling systems, or equivalent re-

*Together with No. 07–589, *PSEG Fossil LLC et al.* v. *Riverkeeper, Inc., et al.,* and No. 07–597, *Utility Water Act Group* v. *Riverkeeper, Inc., et al.,* also on certiorari to the same court.

ductions in impingement and entrainment, as it had done in its Phase I rules, in part because the cost of rendering existing facilities closed-cycle compliant would be nine times the estimated cost of compliance with the Phase II performance standards, and because other technologies could approach the performance of closed-cycle operation. The Phase II rules also permit site-specific variances from the national performance standards, provided that the permit-issuing authority imposes remedial measures that yield results "as close as practicable to the applicable performance standards." §125.94(a)(5)(i), (ii). Respondents—environmental groups and various States—challenged the Phase II regulations. Concluding that cost-benefit analysis is impermissible under 33 U. S. C. §1326(b), the Second Circuit found the site-specific cost-benefit variance provision unlawful and remanded the regulations to the EPA for it to clarify whether it had relied on cost-benefit analysis in setting the national performance standards.

Held: The EPA permissibly relied on cost-benefit analysis in setting the national performance standards and in providing for cost-benefit variances from those standards as part of the Phase II regulations. Pp. 7–16.

(a) The EPA's view that §1326(b)'s "best technology available for minimizing adverse environmental impact" standard permits consideration of the technology's costs and of the relationship between those costs and the environmental benefits produced governs if it is a reasonable interpretation of the statute—not necessarily the only possible interpretation, nor even the interpretation deemed *most* reasonable by the courts. *Chevron U. S. A. Inc.* v. *Natural Resources Defense Council, Inc.*, 467 U. S. 837, 843–844. The Second Circuit took "best technology" to mean the technology that achieves the greatest reduction in adverse environmental impacts at a reasonable cost to the industry, but it may also describe the technology that *most efficiently* produces a good, even if it produces a lesser quantity of that good than other available technologies. This reading is not precluded by the phrase "for minimizing adverse environmental impact." Minimizing admits of degree and is not necessarily used to refer exclusively to the "greatest possible reduction." Other Clean Water Act provisions show that when Congress wished to mandate the greatest feasible reduction in water pollution, it used plain language, *e.g.*, "elimination of discharges of all pollutants," §1311(b)(2)(A). Thus, §1326(b)'s use of the less ambitious goal of "minimizing adverse environmental impact" suggests that the EPA has some discretion to determine the extent of reduction warranted under the circumstances, plausibly involving a consideration of the benefits derived from reductions and the costs of achieving them. Pp. 7–9.

(b) Considering §1326(b)'s text, and comparing it with the text and statutory factors applicable to parallel Clean Water Act provisions, prompts the conclusion that it was well within the bounds of reasonable interpretation for the EPA to conclude that cost-benefit analysis is not categorically forbidden. In the Phase II rules the EPA sought only to avoid extreme disparities between costs and benefits, limiting variances from Phase II's "national performance standards" to circumstances where the costs are "significantly greater than the benefits" of compliance. 40 CFR §125.94(a)(5)(ii). In defining "national performance standards" the EPA assumed the application of technologies whose benefits approach those estimated for closed-cycle cooling systems at a fraction of the cost. That the EPA has for over thirty years interpreted §1326(b) to permit a comparison of costs and benefits, while not conclusive, also tends to show that its interpretation is reasonable and hence a legitimate exercise of its discretion. Even respondents and the Second Circuit ultimately recognize that some comparison of costs and benefits is permitted. The Second Circuit held that §1326(b) mandates only those technologies whose costs can be reasonably borne by the industry. But whether it is reasonable to bear a particular cost can very well depend on the resulting benefits. Likewise, respondents concede that the EPA need not require that industry spend billions to save one more fish. This concedes the principle, and there is no statutory basis for limiting the comparison of costs and benefits to situations where the benefits are *de minimis* rather than significantly disproportionate. Pp. 9–16.

475 F. 3d 83, reversed and remanded.

SCALIA, J., delivered the opinion of the Court, in which ROBERTS, C. J., and KENNEDY, THOMAS, and ALITO, JJ., joined. BREYER, J., filed an opinion concurring in part and dissenting in part. STEVENS, J., filed a dissenting opinion, in which SOUTER and GINSBURG, JJ., joined.

NOTICE: This opinion is subject to formal revision before publication in the preliminary print of the United States Reports. Readers are requested to notify the Reporter of Decisions, Supreme Court of the United States, Washington, D. C. 20543, of any typographical or other formal errors, in order that corrections may be made before the preliminary print goes to press.

SUPREME COURT OF THE UNITED STATES

Nos. 07–588, 07–589 and 07–597

ENTERGY CORPORATION, PETITIONER
07–588 *v.*
RIVERKEEPER, INC., ET AL.

PSEG FOSSIL LLC, ET AL., PETITIONERS
07–589 *v.*
RIVERKEEPER, INC., ET AL.

UTILITY WATER ACT GROUP, PETITIONER
07–597 *v.*
RIVERKEEPER, INC., ET AL.

ON WRITS OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE SECOND CIRCUIT

[April 1, 2009]

JUSTICE SCALIA delivered the opinion of the Court.

These cases concern a set of regulations adopted by the Environmental Protection Agency (EPA or agency) under §316(b) of the Clean Water Act, 33 U. S. C. §1326(b). 69 Fed. Reg. 41576 (2004). Respondents—environmental groups and various States[1]—challenged those regulations, and the Second Circuit set them aside. *Riverkeeper, Inc.* v.

[1] The EPA and its Administrator appeared as respondents in support of petitioners. See Brief for Federal Parties as Respondents Supporting Petitioners. References to "respondents" throughout the opinion refer only to those parties challenging the EPA rules at issue in these cases.

EPA, 475 F. 3d 83, 99–100 (2007). The issue for our decision is whether, as the Second Circuit held, the EPA is not permitted to use cost-benefit analysis in determining the content of regulations promulgated under §1326(b).

I

Petitioners operate—or represent those who operate—large powerplants. In the course of generating power, those plants also generate large amounts of heat. To cool their facilities, petitioners employ "cooling water intake structures" that extract water from nearby water sources. These structures pose various threats to the environment, chief among them the squashing against intake screens (elegantly called "impingement") or suction into the cooling system ("entrainment") of aquatic organisms that live in the affected water sources. See 69 Fed. Reg. 41586. Accordingly, the facilities are subject to regulation under the Clean Water Act, 33 U. S. C. §1251 *et seq.*, which mandates:

> "Any standard established pursuant to section 1311 of this title or section 1316 of this title and applicable to a point source shall require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." §1326(b).

Sections 1311 and 1316, in turn, employ a variety of "best technology" standards to regulate the discharge of effluents into the Nation's waters.

The §1326(b) regulations at issue here were promulgated by the EPA after nearly three decades in which the determination of the "best technology available for minimizing [cooling water intake structures'] adverse environmental impact" was made by permit-issuing authorities on a case-by-case basis, without benefit of a governing regulation. The EPA's initial attempt at such a regulation came to nought when the Fourth Circuit determined that the agency had failed to adhere to the procedural requirements of the Administrative Procedure Act. *Appalachian Power Co.* v. *Train*, 566 F. 2d 451, 457 (1977). The EPA withdrew the regulation, 44 Fed. Reg. 32956 (1979), and instead published "draft guidance" for use in implementing §1326(b)'s requirements via site-specific permit decisions under §1342. See EPA, Office of Water Enforcement Permits Div., {Draft} Guidance for Evaluating the Adverse Impact of Cooling Water Intake Structures on the Aquatic Environment: Section 316(b) P. L. 92–500, (May 1, 1977), at http://www.epa.gov/waterscience/316b/files/1977AEIguid.pdf, (all Internet materials as visited Mar. 30, 2009, and available in Clerk of Court's case file); 69 Fed. Reg. 41584 (describing system of case-by-case permits under the draft guidance).

In 1995, the EPA entered into a consent decree which, as subsequently amended, set a multiphase timetable for the EPA to promulgate regulations under §1326(b). See *Riverkeeper, Inc.* v. *Whitman*, No. 93 Civ. 0314 (AGS), 2001 WL 1505497, *1 (SDNY, Nov. 27, 2001). In the first phase the EPA adopted regulations governing certain new, large cooling water intake structures. 66 Fed. Reg. 65256 (2001) (Phase I rules); see 40 CFR §§125.80(a), 125.81(a) (2008). Those rules require new facilities with water-intake flow greater than 10 million gallons per day to, among other things, restrict their inflow "to a level commensurate with that which can be attained by a closed-cycle recirculating cooling water system."[2] §125.84(b)(1). New facilities with water-intake flow between 2 million

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[2] Closed-cycle cooling systems recirculate the water used to cool the facility, and consequently extract less water from the adjacent waterway, proportionately reducing impingement and entrainment. *Riverkeeper, Inc.* v. *EPA*, 358 F. 3d 174, 182, n. 5 (CA2 2004); 69 Fed. Reg. 41601, and n. 44 (2004).

and 10 million gallons per day may alternatively comply by, among other things, reducing the volume and velocity of water removal to certain levels. §125.84(c). And all facilities may alternatively comply by demonstrating, among other things, "that the technologies employed will reduce the level of adverse environmental impact . . . to a comparable level" to what would be achieved by using a closed-cycle cooling system. §125.84(d). These regulations were upheld in large part by the Second Circuit in *Riverkeeper, Inc.* v. *EPA*, 358 F. 3d 174 (2004).

The EPA then adopted the so-called "Phase II" rules at issue here.[3] 69 Fed. Reg. 41576. They apply to existing facilities that are point sources, whose primary activity is the generation and transmission (or sale for transmission) of electricity, and whose water-intake flow is more than 50 million gallons of water per day, at least 25 percent of which is used for cooling purposes. *Ibid.* Over 500 facilities, accounting for approximately 53 percent of the Nation's electric-power generating capacity, fall within Phase II's ambit. See EPA, Economic and Benefits Analysis for the Final Section 316(b) Phase II Existing Facilities Rule, A3–13, Table A3–4 (Feb. 2004), online at http://www.epa.gov/waterscience/316b/phase2/econbenefits/final/a3.pdf. Those facilities remove on average more than 214 billion gallons of water per day, causing impingement and entrainment of over 3.4 billion aquatic organisms per year. 69 Fed. Reg. 41586.

To address those environmental impacts, the EPA set "national performance standards," requiring Phase II facilities (with some exceptions) to reduce "impingement mortality for all life stages of fish and shellfish by 80 to 95

[3] The EPA has also adopted Phase III rules for facilities not subject to the Phase I and Phase II regulations. 71 Fed. Reg. 35006 (2006). A challenge to those regulations is currently before the Fifth Circuit, where proceedings have been stayed pending disposition of these cases. See *ConocoPhillips Co.* v. *EPA*, No. 06–60662.

percent from the calculation baseline"; a subset of facilities must also reduce entrainment of such aquatic organisms by "60 to 90 percent from the calculation baseline." 40 CFR §125.94(b)(1), (2); see §125.93 (defining "calculation baseline"). Those targets are based on the environmental improvements achievable through deployment of a mix of remedial technologies, 69 Fed. Reg. 41599, which the EPA determined were "commercially available and economically practicable," *id.*, at 41602.

In its Phase II rules, however, the EPA expressly declined to mandate adoption of closed-cycle cooling systems or equivalent reductions in impingement and entrainment, as it had done for new facilities subject to the Phase I rules. *Id.*, at 41601. It refused to take that step in part because of the "generally high costs" of converting existing facilities to closed-cycle operation, and because "other technologies approach the performance of this option." *Id.*, at 41605. Thus, while closed-cycle cooling systems could reduce impingement and entrainment mortality by up to 98 percent, *id.*, at 41601, (compared to the Phase II targets of 80 to 95 percent impingement reduction), the cost of rendering all Phase II facilities closed-cycle-compliant would be approximately $3.5 billion per year, *id.*, at 41605, nine times the estimated cost of compliance with the Phase II performance standards, *id.*, at 41666. Moreover, Phase II facilities compelled to convert to closed-cycle cooling systems "would produce 2.4 percent to 4.0 percent less electricity even while burning the same amount of coal," possibly requiring the construction of "20 additional 400–MW plants . . . to replace the generating capacity lost." *Id.*, at 41605. The EPA thus concluded that "[a]lthough not identical, the ranges of impingement and entrainment reduction are similar under both options. . . . [Benefits of compliance with the Phase II rules] can approach those of closed-cycle recirculating at less cost with fewer implementation problems." *Id.*, at 41606.

The regulations permit the issuance of site-specific variances from the national performance standards if a facility can demonstrate either that the costs of compliance are "significantly greater than" the costs considered by the agency in setting the standards, 40 CFR §125.94(a)(5)(i), or that the costs of compliance "would be significantly greater than the benefits of complying with the applicable performance standards," §125.94(a)(5)(ii). Where a variance is warranted, the permit-issuing authority must impose remedial measures that yield results "as close as practicable to the applicable performance standards." §125.94(a)(5)(i), (ii).

Respondents challenged the EPA's Phase II regulations, and the Second Circuit granted their petition for review and remanded the regulations to the EPA. The Second Circuit identified two ways in which the EPA could permissibly consider costs under 33 U. S. C. §1326(b): (1) in determining whether the costs of remediation "can be 'reasonably borne' by the industry," and (2) in determining which remedial technologies are the most cost-effective, that is, the technologies that reach a specified level of benefit at the lowest cost. 475 F. 3d, at 99–100. See also *id.*, at 98, and n. 10. It concluded, however, that cost-benefit analysis, which "compares the costs and benefits of various ends, and chooses the end with the best net benefits," *id.*, at 98, is impermissible under §1326(b), *id.*, at 100.

The Court of Appeals held the site-specific cost-benefit variance provision to be unlawful. *Id.*, at 114. Finding it unclear whether the EPA had relied on cost-benefit analysis in setting the national performance standards, or had only used cost-effectiveness analysis, it remanded to the agency for clarification of that point. *Id.*, at 104–105. (The remand was also based on other grounds which are not at issue here.) The EPA suspended operation of the Phase II rules pending further rulemaking. 72 Fed. Reg.

37107 (2007). We then granted certiorari limited to the following question: "Whether [§1326(b)] . . . authorizes the [EPA] to compare costs with benefits in determining 'the best technology available for minimizing adverse environmental impact' at cooling water intake structures." 552 U. S. ___ (2008).

II

In setting the Phase II national performance standards and providing for site-specific cost-benefit variances, the EPA relied on its view that §1326(b)'s "best technology available" standard permits consideration of the technology's costs, 69 Fed. Reg. 41626, and of the relationship between those costs and the environmental benefits produced, *id.*, at 41603. That view governs if it is a reasonable interpretation of the statute—not necessarily the only possible interpretation, nor even the interpretation deemed *most* reasonable by the courts. *Chevron U. S. A. Inc.* v. *Natural Resources Defense Council, Inc.*, 467 U. S. 837, 843–844 (1984).[4]

As we have described, §1326(b) instructs the EPA to set standards for cooling water intake structures that reflect "the best technology available for minimizing adverse environmental impact." The Second Circuit took that

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[4] The dissent finds it "puzzling" that we invoke this proposition (that a reasonable agency interpretation prevails) at the "outset," omitting the supposedly prior inquiry of "'whether Congress has directly spoken to the precise question at issue.'" *Post*, at 6, n. 5 (opinion of STEVENS, J.) (quoting *Chevron*, 467 U. S., at 842). But surely if Congress has directly spoken to an issue then any agency interpretation contradicting what Congress has said would be unreasonable.

What is truly "puzzling" is the dissent's accompanying charge that the Court's failure to conduct the *Chevron* step-one inquiry at the outset "reflects [its] reluctance to consider the possibility . . . that Congress' silence may have meant to foreclose cost-benefit analysis." *Post*, at 6, n. 5. Our discussion of that issue, *infra*, at 11, speaks for itself.

language to mean the technology that achieves the greatest reduction in adverse environmental impacts at a cost that can reasonably be borne by the industry. 475 F. 3d, at 99–100. That is certainly a plausible interpretation of the statute. The "best" technology—that which is "most advantageous," Webster's New International Dictionary 258 (2d ed. 1953)—may well be the one that produces the most of some good, here a reduction in adverse environmental impact. But "best technology" may also describe the technology that *most efficiently* produces some good. In common parlance one could certainly use the phrase "best technology" to refer to that which produces a good at the lowest per-unit cost, even if it produces a lesser quantity of that good than other available technologies.

Respondents contend that this latter reading is precluded by the statute's use of the phrase "for minimizing adverse environmental impact." Minimizing, they argue, means reducing to the smallest amount possible, and the "best technology available for minimizing adverse environmental impacts," must be the economically feasible technology that achieves the greatest possible reduction in environmental harm. Brief for Respondents Riverkeeper, Inc. et al. 25–26. But "minimize" is a term that admits of degree and is not necessarily used to refer exclusively to the "greatest possible reduction." For example, elsewhere in the Clean Water Act, Congress declared that the procedures implementing the Act "shall encourage the drastic minimization of paperwork and interagency decision procedures." 33 U. S. C. §1251(f). If respondents' definition of the term "minimize" is correct, the statute's use of the modifier "drastic" is superfluous.

Other provisions in the Clean Water Act also suggest the agency's interpretation. When Congress wished to mandate the greatest feasible reduction in water pollution, it did so in plain language: The provision governing the discharge of toxic pollutants into the Nation's waters requires the EPA to set "effluent limitations [which] shall require the *elimination* of discharges of all pollutants if the Administrator finds . . . that such elimination is technologically and economically achievable," §1311(b)(2)(A) (emphasis added). See also §1316(a)(1) (mandating "where practicable, a standard [for new point sources] permitting *no discharge* of pollutants" (emphasis added)). Section 1326(b)'s use of the less ambitious goal of "minimizing adverse environmental impact" suggests, we think, that the agency retains some discretion to determine the extent of reduction that is warranted under the circumstances. That determination could plausibly involve a consideration of the benefits derived from reductions and the costs of achieving them. Cf. 40 CFR §125.83 (defining "minimize" for purposes of the Phase I regulations as "reduc[ing] to the smallest amount, extent, or degree reasonably possible"). It seems to us, therefore, that the phrase "best technology available," even with the added specification "for minimizing adverse environmental impact," does not unambiguously preclude cost-benefit analysis.[5]

Respondents' alternative (and, alas, also more complex) argument rests upon the structure of the Clean Water Act. The Act provided that during its initial implementation period existing "point sources"—discrete conveyances from which pollutants are or may be discharged, 33 U. S. C. §1362(14)—were subject to "effluent limitations . . . which shall require the application of the *best practicable control technology* currently available." §1311(b)(1)(A) (emphasis

[5] Respondents concede that the term "available" is ambiguous, as it could mean either technologically feasible or economically feasible. But any ambiguity in the term "available" is largely irrelevant. Regardless of the criteria that render a technology "available," the EPA would still have to determine which available technology is the "best" one. And as discussed above, that determination may well involve consideration of the technology's relative costs and benefits.

added). (We shall call this the "BPT" test.) Following that transition period, the Act initially mandated adoption, by July 1, 1983 (later extended to March 31, 1989), of stricter effluent limitations requiring "application of the *best available technology economically achievable* for such category or class, which will result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants." §1311(b)(2)(A) (emphasis added); see *EPA* v. *National Crushed Stone Assn.*, 449 U. S. 64, 69–70 (1980). (We shall call this the "BATEA" test.) Subsequent amendment limited application of this standard to toxic and nonconventional pollutants, and for the remainder established a (presumably laxer) test of "best conventional-pollutant control technology." §1311(b)(2)(E).[6] (We shall call this "BCT.") Finally, §1316 subjected certain categories of new point sources to "the greatest degree of effluent reduction which the Administrator determines to be achievable through application of the *best available demonstrated control technology*." §1316(a)(1) (emphasis added); §1316(b)(1)(B). (We shall call this the "BADT" test.) The provision at issue here, applicable not to effluents but to cooling water intake structures, requires, as we have described, "the *best technology available for minimizing adverse environmental impact*," §1326(b) (emphasis added). (We shall call this the "BTA" test.)

The first four of these tests are elucidated by statutory factor lists that guide their implementation. To take the standards in (presumed) order of increasing stringency, see *Crushed Stone, supra,* at 69–70: In applying the BPT test the EPA is instructed to consider, among other factors, "the total cost of application of technology in relation

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[6]The statute does not contain a hyphen between the words "conventional" and "pollutant." "Conventional pollutant" is a statutory term, however, see 33 U. S. C. §1314(a)(4), and it is clear that in §1311(b)(2)(E) the adjective modifies "pollutant" rather than "control technology." The hyphen makes that clear.

to the effluent reduction benefits to be achieved." §1314(b)(1)(B). In applying the BCT test it is instructed to consider "the *reasonableness of the relationship* between the costs of attaining a reduction in effluents and the effluent reduction benefits derived." §1314(b)(4)(B) (emphasis added). And in applying the BATEA and BADT tests the EPA is instructed to consider the "cost of achieving such effluent reduction." §§1314(b)(2)(B), 1316(b)(1)(B). There is no such elucidating language applicable to the BTA test at issue here. To facilitate comparison, the texts of these five tests, the clarifying factors applicable to them, and the entities to which they apply are set forth in the Appendix, *infra*.

The Second Circuit, in rejecting the EPA's use of cost-benefit analysis, relied in part on the propositions that (1) cost-benefit analysis is precluded under the BATEA and BADT tests; and (2) that, insofar as the permissibility of cost-benefit analysis is concerned, the BTA test (the one at issue here) is to be treated the same as those two. See 475 F. 3d, at 98. It is not obvious to us that the first of these propositions is correct, but we need not pursue that point, since we assuredly do not agree with the second. It is certainly reasonable for the agency to conclude that the BTA test need not be interpreted to permit only what those other two tests permit. Its text is not identical to theirs. It has the relatively modest goal of "minimizing adverse environmental impact" as compared with the BATEA's goal of "eliminating the discharge of all pollutants." And it is unencumbered by specified statutory factors of the sort provided for those other two tests, which omission can reasonably be interpreted to suggest that the EPA is accorded greater discretion in determining its precise content.

Respondents and the dissent argue that the mere fact that §1326(b) does not expressly authorize cost-benefit analysis for the BTA test, though it does so for two of the other tests, displays an intent to forbid its use. This surely proves too much. For while it is true that two of the other tests authorize cost-benefit analysis, it is also true that *all four* of the other tests expressly authorize *some* consideration of costs. Thus, if respondents' and the dissent's conclusion regarding the import of §1326(b)'s silence is correct, it is *a fortiori* true that the BTA test permits *no consideration of cost whatsoever*, not even the "cost-effectiveness" and "feasibility" analysis that the Second Circuit approved, see *supra*, at 6, that the dissent would approve, *post*, at 1–2, and that respondents acknowledge. The inference that respondents and the dissent would draw from the silence is, in any event, implausible, as §1326(b) is silent not only with respect to cost-benefit analysis but with respect to all potentially relevant factors. If silence here implies prohibition, then the EPA could not consider *any* factors in implementing §1326(b)—an obvious logical impossibility. It is eminently reasonable to conclude that §1326(b)'s silence is meant to convey nothing more than a refusal to tie the agency's hands as to whether cost-benefit analysis should be used, and if so to what degree.

Contrary to the dissent's suggestion, see *post*, at 3–4, our decisions in *Whitman* v. *American Trucking Assns., Inc.*, 531 U. S. 457 (2001), and *American Textile Mfrs. Institute, Inc.* v. *Donovan*, 452 U. S. 490 (1981), do not undermine this conclusion. In *American Trucking*, we held that the text of §109 of the Clean Air Act, "interpreted in its statutory and historical context . . . unambiguously bars cost considerations" in setting air quality standards under that provision. 531 U. S., at 471. The relevant "statutory context" included other provisions in the Clean Air Act that expressly authorized consideration of costs, whereas §109 did not. *Id.*, at 467–468. *American Trucking* thus stands for the rather unremarkable proposition that sometimes statutory silence, when viewed in context, is best interpreted as limiting agency discretion. For the reasons discussed earlier, §1326(b)'s silence cannot bear that interpretation.

In *American Textile*, the Court relied in part on a statute's failure to mention cost-benefit analysis in holding that the relevant agency was not required to engage in cost-benefit analysis in setting certain health and safety standards. 452 U. S., at 510–512. But under *Chevron*, that an agency is not *required* to do so does not mean that an agency is not *permitted* to do so.

This extended consideration of the text of §1326(b), and comparison of that with the text and statutory factors applicable to four parallel provisions of the Clean Water Act, lead us to the conclusion that it was well within the bounds of reasonable interpretation for the EPA to conclude that cost-benefit analysis is not categorically forbidden. Other arguments may be available to preclude such a rigorous form of cost-benefit analysis as that which was prescribed under the statute's former BPT standard, which required weighing "the total cost of application of technology" against "the . . . benefits to be achieved." See, *supra*, at 10. But that question is not before us.

In the Phase II requirements challenged here the EPA sought only to avoid extreme disparities between costs and benefits. The agency limited variances from the Phase II "national performance standards" to circumstances where the costs are "significantly greater than the benefits" of compliance. 40 CFR §125.94(a)(5)(ii). In defining the "national performance standards" themselves the EPA assumed the application of technologies whose benefits "approach those estimated" for closed-cycle cooling systems at a fraction of the cost: $389 million per year, 69 Fed. Reg. 41666, as compared with (1) at least $3.5 billion per year to operate compliant closed-cycle cooling systems, *id.,* at 41605 (or $1 billion per year to impose similar requirements on a subset of Phase II facilities, *id.,* at

41606), and (2) significant reduction in the energy output of the altered facilities, *id.*, at 41605. And finally, EPA's assessment of the relatively meager financial benefits of the Phase II regulations that it adopted—reduced impingement and entrainment of 1.4 billion aquatic organisms, *id.*, at 41661, Exh. XII–6, with annualized use-benefits of $83 million, *id.*, at 41662, and non-use benefits of indeterminate value, *id.*, at 41660–41661—when compared to annual costs of $389 million, demonstrates quite clearly that the agency did not select the Phase II regulatory requirements because their benefits equaled their costs.

While not conclusive, it surely tends to show that the EPA's current practice is a reasonable and hence legitimate exercise of its discretion to weigh benefits against costs that the agency has been proceeding in essentially this fashion for over 30 years. See *Alaska Dept. of Environmental Conservation* v. *EPA*, 540 U. S. 461, 487 (2004); *Barnhart* v. *Walton*, 535 U. S. 212, 219–220 (2002). As early as 1977, the agency determined that, while §1326(b) does not *require* cost-benefit analysis, it is also not reasonable to "interpret Section [1326(b)] as requiring use of technology whose cost is wholly disproportionate to the environmental benefit to be gained." *In re Public Service Co. of New Hampshire*, 1 E. A. D. 332, 340 (1977). See also *In re Central Hudson Gas and Electric Corp.*, EPA Decision of the General Counsel, NPDES Permits, No. 63, pp. 371, 381 (July 29, 1977) ("EPA ultimately must demonstrate that the present value of the cumulative annual cost of modifications to cooling water intake structures is not wholly out of proportion to the magnitude of the estimated environmental gains"); *Seacoast Anti-Pollution League* v. *Costle*, 597 F. 2d 306, 311 (CA1 1979) (rejecting challenge to an EPA permit decision that was based in part on the agency's determination that further restrictions would be "'wholly disproportionate to any environmental benefit'"). While the EPA's prior "wholly disproportionate" standard may be somewhat different from its current "significantly greater than" standard, there is nothing in the statute that would indicate that the former is a permissible interpretation while the latter is not.

Indeed, in its review of the EPA's Phase I regulations, the Second Circuit seemed to recognize that §1326(b) permits some form of cost-benefit analysis. In considering a challenge to the EPA's rejection of dry cooling systems[7] as the "best technology available" for Phase I facilities the Second Circuit noted that "while it certainly sounds substantial that dry cooling is 95 percent more effective than closed-cycle cooling, it is undeniably relevant that that difference represents a relatively small improvement over closed-cycle cooling at a very significant cost." *Riverkeeper*, 358 F. 3d, at 194, n. 22. And in the decision below rejecting the use of cost-benefit analysis in the Phase II regulations, the Second Circuit nonetheless interpreted "best technology available" as mandating only those technologies that can "be reasonably borne by the industry." 475 F. 3d, at 99. But whether it is "reasonable" to bear a particular cost may well depend on the resulting benefits; if the only relevant factor was the feasibility of the costs, their reasonableness would be irrelevant.

In the last analysis, even respondents ultimately recognize that some form of cost-benefit analysis is permissible. They acknowledge that the statute's language is "plainly not so constricted as to require EPA to require industry petitioners to spend billions to save one more fish or plankton." Brief for Respondents Riverkeeper, Inc. et al. 29. This concedes the principle—the permissibility of at least some cost-benefit analysis—and we see no statutory basis for limiting its use to situations where the benefits

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[7] Dry cooling systems use air drafts to remove heat, and accordingly remove little or no water from surrounding water sources. See 66 Fed. Reg. 65282 (2001).

are *de minimis* rather than significantly disproportionate.

* * *

We conclude that the EPA permissibly relied on cost-benefit analysis in setting the national performance standards and in providing for cost-benefit variances from those standards as part of the Phase II regulations. The Court of Appeals' reliance in part on the agency's use of cost-benefit analysis in invalidating the site-specific cost-benefit variance provision, 475 F. 3d, at 114, was therefore in error, as was its remand of the national performance standards for clarification of whether cost-benefit analysis was impermissibly used, *id.*, at 104–105. We of course express no view on the remaining bases for the Second Circuit's remand which did not depend on the permissibility of cost-benefit analysis. See *id.*, at 108, 110, 113, 115, 117, 120.[8] The judgment of the Court of Appeals is reversed, and the cases are remanded for further proceedings consistent with this opinion.

It is so ordered.

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[8] JUSTICE BREYER would remand for the additional reason of what he regards as the agency's inadequate explanation of the change in its criterion for variances—from a relationship of costs to benefits that is "'wholly disproportionate'" to one that is "'significantly greater.'" *Post*, at 7–8 (opinion concurring in part and dissenting in part). That question can have no bearing upon whether the EPA can use cost-benefit analysis, which is the only question presented here. It seems to us, in any case, that the EPA's explanation was ample. It explained that the "wholly out of proportion" standard was inappropriate for the existing facilities subject to the Phase II rules because those facilities lack "the greater flexibility available to new facilities for selecting the location of their intakes and installing technologies at lower costs relative to the costs associated with retrofitting existing facilities," and because "economically impracticable impacts on energy prices, production costs, and energy production . . . could occur if large numbers of Phase II existing facilities incurred costs that were more than 'significantly greater' than but not 'wholly out of proportion' to the costs in the EPA's record." 68 Fed. Reg. 13541 (2003).

APPENDIX TO OPINION OF THE COURT

Statutory Standard	**Statutorily Mandated Factors**	**Entities Subject to Regulation**
BPT: "[E]ffluent limitations . . . which shall require the application of the *best practicable control technology currently available*." 33 U. S. C. §1311(b)(1)(A) (emphasis added).	"Factors relating to the assessment of best practicable control technology currently available . . . shall include consideration of the total cost of application of technology in relation to the effluent reduction benefits to be achieved." 33 U. S. C. §1314(b)(1)(B).	Existing point sources during the Clean Water Act's initial implementation phase.
BCT: "[E]ffluent limitations . . . which shall require application of the *best conventional pollutant control technology*." 33 U. S. C. §1311(b)(2)(E) (emphasis added).	"Factors relating to the assessment of best conventional pollutant control technology . . . shall include consideration of the reasonableness of the relationship between the costs of attaining a reduction in effluents and the effluent reduction benefits derived." 33 U. S. C. §1314(b)(4)(B).	Existing point sources that discharge "conventional pollutants" as defined by the EPA under 33 U. S. C. §1314(a)(4).
BATEA: "[E]ffluent limitations . . . which . . . shall require application of the *best available technology economically achievable* . . . which will result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants." 33 U. S. C. §1311(b)(2)(A) (emphasis added).	"Factors relating to the assessment of best available technology shall take into account . . . the cost of achieving such effluent reduction." 33 U. S. C. §1314(b)(2)(B).	Existing point sources that discharge toxic pollutants and non-conventional pollutants.

Appendix to opinion of the Court

Statutory Standard	**Statutorily Mandated Factors**	**Entities Subject to Regulation**
BADT: "[A] standard for the control of the discharge of pollutants which reflects the greatest degree of effluent reduction with the Administrator determines to be achievable through application of the *best available demonstrated control technology.*" 33 U. S. C. §1316(a)(1) (emphasis added).	"[T]he Administrator shall take into consideration the cost of achieving such effluent reduction, and any non-water quality environmental impact and energy requirements." 33 U. S. C. §1316(b)(1)(B).	New point sources within the categories of sources identified by the EPA under 33 U. S. C. §1316(b)(1)(A).
BTA: "Any standard . . . applicable to a point source shall require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." 33 U. S. C. §1326(b).	N/A	Point sources that operate cooling water intake structures.

SUPREME COURT OF THE UNITED STATES

Nos. 07–588, 07–589 and 07–597

ENTERGY CORPORATION, PETITIONER
07–588 *v.*
RIVERKEEPER, INC., ET AL.

PSEG FOSSIL LLC, ET AL., PETITIONERS
07–589 *v.*
RIVERKEEPER, INC., ET AL.

UTILITY WATER ACT GROUP, PETITIONER
07–597 *v.*
RIVERKEEPER, INC., ET AL.

ON WRITS OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE SECOND CIRCUIT

[April 1, 2009]

JUSTICE BREYER, concurring in part and dissenting in part.

I agree with the Court that the relevant statutory language authorizes the Environmental Protection Agency (EPA) to compare costs and benefits. *Ante*, at 7–13. Nonetheless the drafting history and legislative history of related provisions, Pub. L. 92–500, §§301, 304, 86 Stat. 844, 850, as amended, 33 U. S. C. §§1311, 1314, make clear that those who sponsored the legislation intended the law's text to be read as restricting, though not forbidding, the use of cost-benefit comparisons. And I would apply that text accordingly.

I

Section 301 provides that, not later than 1977, effluent limitations for point sources shall require the application of "*best practicable* control technology," §301(b)(1)(A), 86 Stat. 845 (emphasis added); and that, not later than 1983 (later extended to 1989), effluent limitations for categories and classes of point sources shall require application of the "*best available* technology economically achievable," §301(b)(2)(A), *ibid.* (emphasis added). Section 304(b), in turn, identifies the factors that the Agency shall take into account in determining (1) "*best practicable* control technology" and (2) "*best available* technology." 86 Stat. 851 (emphasis added).

With respect to the first, the statute provides that the factors taken into account by the Agency "shall include consideration of the total cost of application of technology in relation to the effluent reduction benefits to be achieved from such application . . . and such other factors as the Administrator deems appropriate." §304(b)(1)(B), *ibid.* With respect to the second, the statute says that the Agency "shall take into account . . . the cost of achieving such effluent reduction" and "such other factors as the Administrator deems appropriate." §304(b)(2)(B), *ibid.*

The drafting history makes clear that the statute reflects a compromise. In the House version of the legislation, the Agency was to consider "the cost and the economic, social, and environmental impact of achieving such effluent reduction" when determining both "*best practicable*" and "*best available*" technology. H. R. 11896, 92d Cong., 2d Sess., §§304(b)(1)(B), (b)(2)(B) (1972) (as reported from committee). The House Report explained that the "*best available* technology" standard was needed—as opposed to mandating the elimination of discharge of pollutants—because "the difference in the cost of 100 percent elimination of pollutants as compared to the cost of removal of 97–99 percent of the pollutants in an effluent can far exceed any reasonable benefit to be achieved. In most cases, the cost of removal of the last few percentage points increases expo[n]entially." H. R. Rep. No. 92–911, p. 103 (1972).

In the Senate version, the Agency was to consider "the cost of achieving such effluent reduction" when determining both "*best practicable*" and "*best available*" technology. S. 2770, 92d Cong., 1st Sess., §§304(b)(1)(B), (b)(2)(B) (1971) (as reported from committee). The Senate Report explains that "the technology must be available at a cost . . . which the Administrator determines to be reasonable." S. Rep. No. 92–414, p. 52 (1971) (hereinafter S. Rep.). But it said nothing about comparing costs and benefits.

The final statute reflects a modification of the House's language with respect to "*best practicable*," and an adoption of the Senate's language with respect to "*best available*." S. Conf. Rep. No. 92–1236, pp. 124–125 (1972). The final statute does not *require* the Agency to compare costs to benefits when determining "*best available* technology," but neither does it expressly *forbid* such a comparison.

The strongest evidence in the legislative history supporting the respondents' position—namely, that Congress intended to forbid comparisons of costs and benefits when determining the "*best available* technology"—can be found in a written discussion of the Act's provisions distributed to the Senate by Senator Edmund Muskie, the Act's principal sponsor, when he submitted the Conference Report for the Senate's consideration. 118 Cong. Rec. 33693 (1972). The relevant part of that discussion points out that, as to "*best practicable* technology," the statute requires application of a "balancing test between total cost and effluent reduction benefits." *Id.*, at 33696; see §304(b)(1)(B). But as to "*best available* technology," it states: "While cost should be a factor in the Administrator's judgment, no balancing test will be required." *Ibid.;* see §304(b)(2)(B). And Senator Muskie's discussion later speaks of the agency "evaluat[ing] . . . what needs to be done" to eliminate pollutant discharge and "what is achievable," both "without regard to cost." *Ibid.*

As this language suggests, the Act's sponsors had reasons for minimizing the EPA's investigation of, and reliance upon, cost-benefit comparisons. The preparation of formal cost-benefit analyses can take too much time, thereby delaying regulation. And the sponsors feared that such analyses would emphasize easily quantifiable factors over more qualitative factors (particularly environmental factors, for example, the value of preserving non-marketable species of fish). See S. Rep., at 47. Above all, they hoped that minimizing the use of cost-benefit comparisons would force the development of cheaper control technologies; and doing so, whatever the initial inefficiencies, would eventually mean cheaper, more effective cleanup. See *id.*, at 50–51.

Nonetheless, neither the sponsors' language nor the underlying rationale requires the Act to be read in a way that would *forbid* cost-benefit comparisons. Any such total prohibition would be difficult to enforce, for every real choice requires a decisionmaker to weigh advantages against disadvantages, and disadvantages can be seen in terms of (often quantifiable) costs. Moreover, an absolute prohibition would bring about irrational results. As the respondents themselves say, it would make no sense to require plants to "spend billions to save one more fish or plankton." Brief for Respondents Riverkeeper, Inc., et al. 29. That is so even if the industry might somehow afford those billions. And it is particularly so in an age of limited resources available to deal with grave environmental problems, where too much wasteful expenditure devoted to one problem may well mean considerably fewer resources available to deal effectively with other (perhaps more serious) problems.

Thus Senator Muskie used nuanced language, which one can read as leaving to the Agency a degree of authority to make cost-benefit comparisons in a manner that is sensitive both to the need for such comparisons and to the concerns that the law's sponsors expressed. The relevant statement begins by listing various factors that the statute *requires* the Administrator to take into account when applying the phrase "practicable" to "classes and categories." 118 Cong. Rec. 33696. It states that, when doing so, the Administrator *must* apply (as the statute specifies) a "balancing test between total cost and effluent reduction benefits." *Ibid.* At the same time, it seeks to reduce the likelihood that the Administrator will place too much weight upon high costs by adding that the balancing test "is intended to limit the application of technology only where the additional degree of effluent reduction is wholly out of proportion to the costs of achieving" a "marginal level of reduction." *Ibid.*

Senator Muskie's statement then considers the *"different test"* that the statute requires the Administrator to apply when determining the "'*best available*'" technology. *Ibid.* (emphasis added). Under that test, the Administrator "may consider a broader range of technological alternatives." *Ibid.* And in determining what is "'*best available*' for a category or class, the Administrator is expected to apply the same principles involved in making the determination of '*best practicable*' . . . except as to cost-benefit analysis." *Ibid.* (emphasis added). That is, "[w]hile cost should be a factor . . . no balancing test will be *required*." *Ibid.* (emphasis added). Rather, *"[t]he Administrator will be bound by a test of reasonableness."* *Ibid.* (emphasis added). The statement adds that the "'*best available*'" standard "is intended to reflect the need to press toward increasingly higher levels of control." *Ibid.* (emphasis added). And "the reasonableness of what is 'economically achievable' should *reflect* an evaluation of what needs to be done to move toward the elimination of the discharge of pollutants and what is achievable through the application of available technology—without regard to cost." *Ibid.*

(emphasis added).

I believe, as I said, that this language is deliberately nuanced. The statement says that where the statute uses the term "*best practicable*," the statute *requires* comparisons of costs and benefits; but where the statute uses the term "*best available*," such comparisons are not "*required*." *Ibid.* (emphasis added). Senator Muskie does not say that all efforts to compare costs and benefits are *forbidden*.

Moreover, the statement points out that where the statute uses the term "*best available*," the Administrator "will be bound by a test of *reasonableness.*" *Ibid.* (emphasis added). It adds that the Administrator should apply this test in a way that *reflects* its ideal objective, moving as closely as is technologically possible to the elimination of pollution. It thereby says the Administrator should consider, *i.e.*, take into account, how much pollution would still remain if the *best available* technology were to be applied everywhere—"without regard to cost." *Ibid.* It does not say that the Administrator *must* set the standard based solely on the result of that determination. (It would be difficult to reconcile the alternative, more absolute reading of this language with the Senator's earlier "test of reasonableness.")

I say that one *may*, not that one *must*, read Senator Muskie's statement this way. But to read it differently would put the Agency in conflict with the test of reasonableness by threatening to impose massive costs far in excess of any benefit. For 30 years the EPA has read the statute and its history in this way. The EPA has thought that it would not be "reasonable to interpret Section 316(b) as requiring use of technology whose cost is *wholly disproportionate* to the environmental benefit to be gained." *In re Pub. Serv. Co. of N. H. (Seabrook Station, Units 1 and 2)*, 1 E. A. D. 332, 340 (1977), remanded on other grounds, *Seacoast Anti-Pollution League* v. *Costle*, 572 F. 2d 872 (CA1 1978) (emphasis added); see also *In re*

Central Hudson Gas & Elec. Corp., EPA Decision of the General Counsel, NPDES Permits, No. 63, p. 371 (July 29, 1977) (also applying a "wholly disproportionate" test); *In re Pub. Serv. Co. of N. H.*, 1 E. A. D. 455 (1978) (same). "[T]his Court will normally accord particular deference to an agency interpretation of 'longstanding' duration." *Barnhart* v. *Walton*, 535 U. S. 212, 220 (2002). And for the last 30 years, the EPA has given the statute a permissive reading without suggesting that in doing so it was ignoring or thwarting the intent of the Congress that wrote the statute.

The EPA's reading of the statute would seem to permit it to describe environmental benefits in non-monetized terms and to evaluate both costs and benefits in accordance with its expert judgment and scientific knowledge. The Agency can thereby avoid lengthy formal cost-benefit proceedings and futile attempts at comprehensive monetization, see 69 Fed. Reg. 41661–41662; take account of Congress' technology-forcing objectives; and still prevent results that are absurd or unreasonable in light of extreme disparities between costs and benefits. This approach, in my view, rests upon a "reasonable interpretation" of the statute—legislative history included. Hence it is lawful. *Chevron U. S. A. Inc.* v. *Natural Resources Defense Council, Inc.*, 467 U. S. 837, 844 (1984). Most of what the majority says is consistent with this view, and to that extent I agree with its opinion.

II

The cases before us, however, present an additional problem. We here consider a rule that permits variances from national standards if a facility demonstrates that its costs would be "significantly greater than the benefits of complying." 40 CFR §125.94(a)(5)(ii) (2008). The words "significantly greater" differ from the words the EPA has traditionally used to describe its standard, namely, "wholly disproportionate." Perhaps the EPA does not mean to make much of that difference. But if it means the new words to set forth a new and different test, the EPA must adequately explain why it has changed its standard. *Motor Vehicle Mfrs. Assn. of United States, Inc.* v. *State Farm Mut. Automobile Ins. Co.*, 463 U. S. 29, 42–43 (1983); *National Cable & Telecommunications Assn.* v. *Brand X Internet*, 545 U. S. 967, 981 (2005); *Thomas Jefferson Univ.* v. *Shalala*, 512 U. S. 504, 524, n. 3 (1994) (THOMAS, J., dissenting).

I am not convinced the EPA has successfully explained the basis for the change. It has referred to the fact that existing facilities have less flexibility than new facilities with respect to installing new technologies, and it has pointed to special, energy-related impacts of regulation. 68 Fed. Reg. 13541 (2003) (proposed rule). But it has not explained why the traditional "wholly disproportionate" standard cannot do the job now, when the EPA has used that standard (for existing facilities and otherwise) with apparent success in the past. See, *e.g.*, *Central Hudson, supra*.

Consequently, like the majority, I would remand these cases to the Court of Appeals. But unlike the majority I would permit that court to remand the cases to the EPA so that the EPA can either apply its traditional "wholly disproportionate" standard or provide an adequately reasoned explanation for the change.

SUPREME COURT OF THE UNITED STATES

Nos. 07–588, 07–589 and 07–597

ENTERGY CORPORATION, PETITIONER
07–588 *v.*
RIVERKEEPER, INC., ET AL.

PSEG FOSSIL LLC, ET AL., PETITIONERS
07–589 *v.*
RIVERKEEPER, INC., ET AL.

UTILITY WATER ACT GROUP, PETITIONER
07–597 *v.*
RIVERKEEPER, INC., ET AL.

ON WRITS OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE SECOND CIRCUIT

[April 1, 2009]

JUSTICE STEVENS, with whom JUSTICE SOUTER and JUSTICE GINSBURG join, dissenting.

Section 316(b) of the Clean Water Act (CWA), 33 U. S. C. §1326(b), which governs industrial powerplant water intake structures, provides that the Environmental Protection Agency (EPA or Agency) "shall require" that such structures "reflect the best technology available for minimizing adverse environmental impact." The EPA has interpreted that mandate to authorize the use of cost-benefit analysis in promulgating regulations under §316(b). For instance, under the Agency's interpretation, technology that would otherwise qualify as the best available need not be used if its costs are "significantly greater than the benefits" of compliance. 40 CFR §125.94(a)(5)(ii) (2008).

Like the Court of Appeals, I am convinced that the EPA has misinterpreted the plain text of §316(b). Unless costs are so high that the best technology is not "available," Congress has decided that they are outweighed by the benefits of minimizing adverse environmental impact. Section 316(b) neither expressly nor implicitly authorizes the EPA to use cost-benefit analysis when setting regulatory standards; fairly read, it prohibits such use.

I

As typically performed by the EPA, cost-benefit analysis requires the Agency to first monetize the costs and benefits of a regulation, balance the results, and then choose the regulation with the greatest net benefits. The process is particularly controversial in the environmental context in which a regulation's financial costs are often more obvious and easier to quantify than its environmental benefits. And cost-benefit analysis often, if not always, yields a result that does not maximize environmental protection.

For instance, although the EPA estimated that water intake structures kill 3.4 billion fish and shellfish each year,[1] see 69 Fed. Reg. 41586, the Agency struggled to calculate the value of the aquatic life that would be pro-

[1] To produce energy, industrial powerplants withdraw billions of gallons of water daily from our Nation's waterways. Thermoelectric powerplants alone demand 39 percent of all freshwater withdrawn nationwide. See Dept. of Energy, Addressing the Critical Link Between Fossil Energy and Water 2 (Oct. 2005), http://www.netl.doe.gov/technologies/coalpower/ewr/pubs/NETL_Water_Paper_Final_Oct.2005.pdf (all Internet materials as visited Mar. 18, 2009, and available in Clerk of Court's case file). The fish and shellfish are killed by "impingement" or "entrainment." Impingement occurs when aquatic organisms are trapped against the screens and grills of water intake structures. Entrainment occurs when these organisms are drawn into the intake structures. See *Riverkeeper, Inc.* v. *EPA*, 475 F. 3d 83, 89 (CA2 2007); 69 Fed. Reg. 41586 (2004).

tected under its §316(b) regulations, *id.*, at 41661. To compensate, the EPA took a shortcut: Instead of monetizing all aquatic life, the Agency counted only those species that are commercially or recreationally harvested, a tiny slice (1.8 percent to be precise) of all impacted fish and shellfish. This narrow focus in turn skewed the Agency's calculation of benefits. When the EPA attempted to value all aquatic life, the benefits measured $735 million.[2] But when the EPA decided to give zero value to the 98.2 percent of fish not commercially or recreationally harvested, the benefits calculation dropped dramatically—to $83 million. *Id.*, at 41666. The Agency acknowledged that its failure to monetize the other 98.2 percent of affected species "'could result in serious misallocation of resources,'" *id.*, at 41660, because its "comparison of complete costs and incomplete benefits does not provide an accurate picture of net benefits to society."[3]

Because benefits can be more accurately monetized in some industries than in others, Congress typically decides whether it is appropriate for an agency to use cost-benefit analysis in crafting regulations. Indeed, this Court has recognized that "[w]hen Congress has intended that an agency engage in cost-benefit analysis, it has clearly indicated such intent on the face of the statute." *American Textile Mfrs. Institute, Inc.* v. *Donovan*, 452 U. S. 490, 510 (1981). Accordingly, we should not treat a provision's silence as an implicit source of cost-benefit authority, particularly when such authority is elsewhere expressly granted and it has the potential to fundamentally alter an

[2] EPA, Economic and Benefits Analysis for the Proposed Section 316(b) Phase II Existing Facilities Rule, p. D1–4 (EPA–821–R–02–001, Feb. 2002), http://www.epa.gov/waterscience/316b/phase2/econbenefits.

[3] EPA, Economic and Benefits Analysis for the Final Section 316(b) Phase II Existing Facilities Rule, p. D1–5 (EPA–821–R–04–005, Feb. 2004), http://www.epa.gov/waterscience/316b/phase2/econbenefits/final.htm.

agency's approach to regulation. Congress, we have noted, "does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions—it does not, one might say, hide elephants in mouseholes." *Whitman* v. *American Trucking Assns., Inc.*, 531 U. S. 457, 467–468 (2001).

When interpreting statutory silence in the past, we have sought guidance from a statute's other provisions. Evidence that Congress confronted an issue in some parts of a statute, while leaving it unaddressed in others, can demonstrate that Congress meant its silence to be decisive. We concluded as much in *American Trucking.* In that case, the Court reviewed the EPA's claim that §109 of the Clean Air Act (CAA), 42 U. S. C. §7409(a) (2000 ed.), authorized the Agency to consider implementation costs in setting ambient air quality standards. We read §109, which was silent on the matter, to prohibit Agency reliance on cost considerations. After examining other provisions in which Congress had given the Agency authority to consider costs, the Court "refused to find implicit in ambiguous sections of the CAA an authorization to consider costs that has elsewhere, and so often, been expressly granted." 531 U. S., at 467. Studied silence, we thus concluded, can be as much a prohibition as an explicit "no."

Further motivating the Court in *American Trucking* was the fact that incorporating implementation costs into the Agency's calculus risked countermanding Congress' decision to protect public health. The cost of implementation, we said, "is *both* so indirectly related to public health *and* so full of potential for canceling the conclusions drawn from direct health effects that it would surely have been expressly mentioned in [the text] had Congress meant it to be considered." *Id.*, at 469.

American Trucking's approach should have guided the Court's reading of §316(b). Nowhere in the text of §316(b) does Congress explicitly authorize the use of cost-benefit analysis as it does elsewhere in the CWA. And the use of cost-benefit analysis, like the consideration of implementation costs in *American Trucking*, "pad[s]" §316(b)'s environmental mandate with tangential economic efficiency concerns. *Id.*, at 468. Yet the majority fails to follow *American Trucking* despite that case's obvious relevance to our inquiry.

II

In 1972, Congress amended the CWA to strike a careful balance between the country's energy demands and its desire to protect the environment. The Act required industry to adopt increasingly advanced technology capable of mitigating its detrimental environmental impact. Not all point sources were subject to strict rules at once. Existing plants were granted time to retrofit with the best technology while new plants were required to incorporate such technology as a matter of design. Although Congress realized that technology standards would necessarily put some firms out of business, see *EPA* v. *National Crushed Stone Assn.*, 449 U. S. 64, 79 (1980), the statute's steady march was toward stricter rules and potentially higher costs.

Section §316(b) was an integral part of the statutory scheme. The provision instructs that "[a]ny standard established pursuant to section 1311 of this title or section 1316 of this title and applicable to a point source shall require that the location, design, construction, and capacity of cooling water intake structures reflect the *best technology available for minimizing adverse environmental impact*." 33 U. S. C. §1326(b) (2006 ed.) (emphasis added).[4] The "best technology available," or "BTA," stan-

[4] The two cross-referenced provisions, §§1311 and 1316, also establish "best technology" standards, the first applicable to existing point sources and the second to new facilities. The reference to these provi-

dard delivers a clear command: To minimize the adverse environmental impact of water intake structures, the EPA must require industry to adopt the best technology available.

Based largely on the observation that §316(b)'s text offers little guidance and therefore delegates some amount of gap-filling authority to the EPA, the Court concludes that the Agency has discretion to rely on cost-benefit analysis. See *ante*, at 11–12. The Court assumes that, by not specifying how the EPA is to determine BTA, Congress intended to give considerable discretion to the EPA to decide how to proceed. Silence, in the majority's view, represents ambiguity and an invitation for the Agency to decide for itself which factors should govern its regulatory approach.

The appropriate analysis requires full consideration of the CWA's structure and legislative history to determine whether Congress contemplated cost-benefit analysis and, if so, under what circumstances it directed the EPA to utilize it. This approach reveals that Congress granted the EPA authority to use cost-benefit analysis in some contexts but not others, and that Congress intend to control, not delegate, when cost-benefit analysis should be used. See *Chevron U. S. A. Inc.* v. *Natural Resources Defense Council, Inc.*, 467 U. S. 837, 842–843 (1984).[5]

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sions in §316(b) merely requires any rule promulgated under those provisions, when applied to a point source with a water intake structure, to incorporate §316(b) standards.

[5] The majority announces at the outset that the EPA's reading of the BTA standard "governs if it is a reasonable interpretation of the statute—not necessarily the only possible interpretation, nor even the interpretation deemed *most* reasonable by the courts." *Ante*, at 7. This observation is puzzling in light of the commonly understood practice that, as a first step, we ask "whether Congress has directly spoken to the precise question at issue." *Chevron*, 467 U. S., at 842. Only later, if Congress' intent is not clear, do we consider the reasonableness of the agency's action. *Id.*, at 843. Assuming ambiguity and moving to the

Powerful evidence of Congress' decision not to authorize cost-benefit analysis in the BTA standard lies in the series of standards adopted to regulate the outflow, or effluent, from industrial powerplants. Passed at the same time as the BTA standard at issue here, the effluent limitation standards imposed increasingly strict technology requirements on industry. In each effluent limitation provision, Congress distinguished its willingness to allow the EPA to consider costs from its willingness to allow the Agency to conduct a cost-benefit analysis. And to the extent Congress permitted cost-benefit analysis, its use was intended to be temporary and exceptional.

The first tier of technology standards applied to existing plants—facilities for which retrofitting would be particularly costly. Congress required these plants to adopt "effluent limitations . . . which shall require the application of the best practicable control technology currently available." 33 U. S. C. §1311(b)(1)(A). Because this "best practicable," or "BPT," standard was meant to ease industry's transition to the new technology-based regime, Congress gave BPT two unique features: First, it would be temporary, remaining in effect only until July 1, 1983.[6] Second, it specified that the EPA was to conduct a cost-benefit analysis in setting BPT requirements by considering "the total cost of application of technology in relation to the effluent reduction benefits to be achieved from such application."[7] §1314(b)(1)(B). Permitting cost-benefit

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second step reflects the Court's reluctance to consider the possibility, which it later laments is "more complex," *ante*, at 9, that Congress' silence may have meant to foreclose cost-benefit analysis.

[6] Congress later extended the deadline to March 31, 1989.

[7] Senator Muskie, the Senate sponsor of the legislation, described the cost-benefit analysis permitted under BPT as decidedly narrow, asserting that "[t]he balancing test between total cost and effluent reduction benefits is intended to limit the application of technology only where the additional degree of effluent reduction is wholly out of proportion to the costs of achieving such marginal level of reduction for any class or

analysis in BPT gave the EPA the ability to cushion the new technology requirement. For a limited time, a technology with costs that exceeded its benefits would not be considered "best."

The second tier of technology standards required existing powerplants to adopt the "best available technology economically achievable" to advance "the national goal of eliminating the discharge of all pollutants." §1311(b)(2)(A). In setting this "best available technology," or "BAT,"[8] standard, Congress gave the EPA a notably different command for deciding what technology would qualify as "best": The EPA was to consider, among other factors, "the cost of achieving such effluent reduction," but Congress did not grant it authority to balance costs with the benefits of stricter regulation. §1314(b)(2)(B). Indeed, in *Crushed Stone* this Court explained that the difference between BPT and BAT was the existence of cost-benefit authority in the first and the absence of that authority in the second. See 449 U. S., at 71 ("Similar directions are given the Administrator for determining effluent reductions attainable from the BAT except that in assessing BAT total cost is no longer to be considered in comparison to effluent reduction benefits").

The BAT standard's legislative history strongly supports the view that Congress purposefully withheld cost-benefit authority for this tier of regulation. See *ibid.*, n. 10. The House of Representatives and the Senate split over the role cost-benefit analysis would play in the BAT provision. The House favored the tool, see H. R. Rep. No. 92–911, p. 107 (1972), 1 Leg. Hist. 794, while the Senate rejected it,

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category of sources." 1 Legislative History of the Water Pollution Control Act Amendments of 1972 (Committee Print compiled for the Senate Committee on Public Works by the Library of Congress), Ser. No. 93–1, p. 170 (1973) (hereinafter Leg. Hist.)

[8] Although the majority calls this "BATEA," the parties refer to the provision as "BAT," and for simplicity, so will I.

see 2 *id.*, at 1183; *id.*, at 1132. The Senate view ultimately prevailed in the final legislation, resulting in a BAT standard that was "not subject to any test of cost in relation to effluent reduction benefits or any form of cost/benefit analysis." 3 Legislative History of the Clean Water Act of 1977: A Continuation of the Legislative History of the Federal Water Pollution Control Act (Committee Print compiled for the Senate Committee on Environment and Public Works by the Library of Congress), Ser. No. 95–14, p. 427 (1978).

The third and strictest regulatory tier was reserved for new point sources—facilities that could incorporate technology improvements into their initial design. These new facilities were required to adopt "the best available demonstrated control technology," or "BADT," which Congress described as "a standard . . . which reflect[s] the greatest degree of effluent reduction." §1316(a)(1). In administering BADT, Congress directed the EPA to consider "the cost of achieving such effluent reduction." §1316(b)(1)(B). But because BADT was meant to be the most stringent standard of all, Congress made no mention of cost-benefit analysis. Again, the silence was intentional. The House's version of BADT originally contained an exemption for point sources for which "the economic, social, and environmental costs bear no reasonable relationship to the economic, social, and environmental benefit to be obtained." 1 Leg. Hist. 798. That this exemption did not appear in the final legislation demonstrates that Congress considered, and rejected, reliance on cost-benefit analysis for BADT.

It is in this light that the BTA standard regulating water intake structures must be viewed. The use of cost-benefit analysis was a critical component of the CWA's structure and a key concern in the legislative process. We should therefore conclude that Congress intended to forbid cost-benefit analysis in one provision of the Act in which it was silent on the matter when it expressly authorized its use in another.[9] See, *e.g.*, *Allison Engine Co.* v. *United States ex rel. Sanders*, 553 U. S. ___, ___ (2008) (slip op., at 7–8); *Russello* v. *United States*, 464 U. S. 16, 23 (1983) ("[W]here Congress includes particular language in one section of a statute but omits it in another . . . , it is generally presumed that Congress acts intentionally and purposely in the disparate inclusion or exclusion" (internal quotation marks omitted)). This is particularly true given Congress' decision that cost-benefit analysis would play a temporary and exceptional role in the CWA to help existing plants transition to the Act's ambitious environmental standards.[10] Allowing cost-benefit analysis in the BTA standard, a permanent mandate applicable to all powerplants, serves no such purpose and instead fundamentally

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[9] The Court argues that, if silence in §316(b) signals the prohibition of cost-benefit analysis, it must also foreclose the consideration of *all* other potentially relevant discretionary factors in setting BTA standards. *Ante*, at 12. This all-or-nothing reasoning rests on the deeply flawed assumption that Congress treated cost-benefit analysis as just one among many factors upon which the EPA could potentially rely to establish BTA. Yet, as explained above, the structure and legislative history of the CWA demonstrate that Congress viewed cost-benefit analysis with special skepticism and controlled its use accordingly. The Court's assumption of equivalence is thus plainly incorrect. Properly read, Congress' silence in §316(b) forbids reliance on the cost-benefit tool but does not foreclose reliance on all other considerations, such as a determination whether a technology is so costly that it is not "available" for industry to adopt.

[10] In 1977, Congress established an additional technology-based standard, commonly referred to as "best conventional pollutant control technology," or "BCT," to govern conventional pollutants previously covered by the BAT standard. See 33 U. S. C. §1311(b)(2)(E). The BCT standard required the EPA to consider, among other factors, "the relationship between the costs of attaining a reduction in effluents and the effluent reduction benefits derived." §1314(b)(4)(B). That Congress expressly authorized cost-benefit analysis in BCT further confirms that Congress treated cost-benefit analysis as exceptional and reserved for itself the authority to decide when it would be used in the Act.

weakens the provision's mandate.[11]

Accordingly, I would hold that the EPA is without authority to perform cost-benefit analysis in setting BTA standards. To the extent the EPA relied on cost-benefit analysis in establishing its BTA regulations,[12] that action was contrary to law, for Congress directly foreclosed such reliance in the statute itself.[13] *Chevron*, 467 U. S., at 843.

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[11] The Court attempts to cabin its holding by suggesting that a "rigorous form of cost-benefit analysis," such as the form "prescribed under the statute's former BPT standard," may not be permitted for setting BTA regulations. *Ante*, at 13. Thus the Court has effectively instructed the Agency that it can perform a cost-benefit analysis so long as it does not resemble the kind of cost-benefit analysis Congress elsewhere authorized in the CWA. The majority's suggested limit on the Agency's discretion can only be read as a concession that cost-benefit analysis, as typically performed, may be inconsistent with the BTA mandate.

[12] The "national performance standards" the EPA adopted were shaped by economic efficiency concerns at the expense of finding the technology that best minimizes adverse environmental impact. In its final rulemaking, the Agency declined to require industrial plants to adopt closed-cycle cooling technology, which by recirculating cooling water requires less water to be withdrawn and thus fewer aquatic organisms to be killed. *Riverkeeper, Inc.* v. *EPA*, 358 F. 3d 174, 182, n. 5 (CA2 2004); 69 Fed. Reg. 41601, and n. 44. This the Agency decided despite its acknowledgment that "closed-cycle, recirculating cooling systems . . . can reduce mortality from impingement by up to 98 percent and entrainment by up to 98 percent." *Id.*, at 41601. The EPA instead permitted individual plants to resort to a "suite" of options so long as the method used reduced impingement and entrainment by the more modest amount of 80 and 60 percent, respectively. See 40 CFR §125.94(b). The Agency also permitted individual plants to obtain a site-specific variance from the national performance standards if they could prove (1) that compliance costs would be "significantly greater than" those the Agency considered when establishing the standards, or (2) that compliance costs "would be significantly greater than the benefits of complying with the applicable performance standards," §125.94(a)(5).

[13] Thus, the Agency's past reliance on a "wholly disproportionate" standard, a mild variant of cost-benefit analysis, is irrelevant. See *ante*, at 14. Because "Congress has directly spoken to the precise

Because we granted certiorari to decide only whether the EPA has authority to conduct cost-benefit analysis, there is no need to define the universe of considerations upon which the EPA can properly rely in administering the BTA standard. I would leave it to the Agency to decide how to proceed in the first instance.

III

Because the Court unsettles the scheme Congress established, I respectfully dissent.

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question at issue," *Chevron*, 467 U. S., at 842, longstanding yet impermissible agency practice cannot ripen into permissible agency practice.

D. Supporting Documents

1. Cost vs. Net Revenues

Cost vs. Net Revenue Comparison

Generating Facility	Estimated gross annual revenue	Estimated annual fuel cost ($)	Estimated net annual revenue ($)	Initial capital Cost ($)	Initial capital % of gross	O&M Cost ($)	O&M % of gross	Energy penalty Cost ($)	Energy penalty % of gross	Total annual cost Cost ($)	Total annual cost % of gross	Total annual cost % of net
ALAMITOS GENERATING STATION	116,300,000	116,050,355	249,645	19,800,000	17.0	2,100,000	1.8	3,100,000	2.7	**25,000,000**	**21.0**	**10,014.2**
CONTRA COSTA POWER PLANT	10,800,000	9,723,800	1,076,201	9,300,000	86.0	500,000	4.6	200,000	1.9	**10,000,000**	**93.0**	**929.2**
DIABLO CANYON POWER PLANT	2,308,100,000	86,351,238	2,221,748,762	84,500,000	3.7	9,100,000	0.4	140,200,000	6.1	**233,800,000**	**10.1**	**10.5**
EL SEGUNDO GENERATING STATION	39,800,000	38,263,526	1,536,475	7,400,000	19.0	400,000	1.0	900,000	2.3	**8,700,000**	**22.0**	**566.2**
HARBOR GENERATING STATION	17,600,000	12,831,980	4,768,020	2,500,000	14.2	100,000	0.6	200,000	1.1	**2,800,000**	**15.9**	**58.7**
HAYNES GENERATING STATION non-CCGT	109,800,000	41,491,168	68,308,832	10,300,000	9%	1,300,000	1%	2,200,000	2%	13,800,000	**13%**	**20%**
HAYNES GENERATING STATION Unit 8 only	225,400,000	120,704,507	104,695,493	4,000,000	1.8	600,000	0.3	1,400,000	0.6	**6,000,000**	**2.7**	**5.7**
HUNTINGTON BEACH GENERATING STATION	76,100,000	66,975,237	9,124,763	12,500,000	16.4	900,000	1.2	2,000,000	2.6	**15,400,000**	**20.2**	**168.8**
MANDALAY GENERATING STATION	22,500,000	21,184,565	1,315,436	5,200,000	23.0	300,000	1.3	300,000	1.3	**5,800,000**	**26.0**	**440.9**
MORRO BAY POWER PLANT	Data not available											
MOSS LANDING POWER PLANT MLPP non-CCGT	73,800,000	62,483,750	11,316,251	18,300,000	25%	1,800,000	0.0	1,800,000	0.024	**21,900,000**	**30%**	**194%**
MOSS LANDING POWER PLANT Units 1 & 2 only	346,000,000	219,049,451	126,950,549	7,100,000	2.1	800,000	0.2	4,000,000	1.2	**11,900,000**	**3.4**	**9.4**
ORMOND BEACH GENERATING STATION	34,800,000	29,010,687	5,789,313	12,500,000	36.0	700,000	2.0	1,100,000	3.2	**14,300,000**	**41.0**	**247.0**
PITTSBURG POWER PLANT	31,500,000	5,058,610	26,441,390	11,800,000	37.0	500,000	1.6	400,000	1.3	**12,700,000**	**40.0**	**48.0**
REDONDO BEACH GENERATING STATION	Data not available											
SAN ONOFRE NUCLEAR GENERATING STATION	2,142,000,000	60,720,348	2,081,279,652	56,000,000	2.6	8,400,000	0.4	144,500,000	6.7	**208,900,000**	**9.8**	**10.0**
SCATTERGOOD GENERATING STATION	143,800,000	93,534,471	50,265,529	15,200,000	10.6	900,000	0.6	2,600,000	1.8	**18,700,000**	**13.0**	**37.2**
Total	$5,698,300,000		$4,714,866,309							$609,700,000	10.7%	12.9%
Nuclear	4,450,100,000		4,303,028,414							442,700,000	10%	10%
Combined Cycle	589,000,000		236,414,062							20,700,000	4%	9%
Conventional Steam	659,200,000		175,423,833							146,300,000	22%	83%

Source:

[1] Gross annual revenue, initial capital, O&M, and energy penalty from Table O-25, Tetra Tech Report
http://www.swrcb.ca.gov/water_issues/programs/npdes/alternativecoolingsystem.shtml

[2] Estimated annual fuel cost based on 2006 EIA 906/920 MMBTU monthly burns, Tetra Tech natural gas prices (for gas units) and FERC Form 1 nuclear fuel expense from page 402-403 line 42 (for nuclear units).

2. Fish Valuation

Cooling Structure Revenue Requirements

	Ormond		Mandalay		Ormond + Mandalay	
	Wet Cooling Tower	Dry Cooling Tower	Wet Cooling Tower	Dry Cooling Tower	Wet Cooling Tower	Dry Cooling Tower
10 Yr Bk Life						
NPV Rev Req ($000)	$180,420	$440,060	$100,617	$155,503	$281,037	$595,563
Levelized Rev Req ($000)	$27,451	$66,956	$15,309	$23,660	$42,760	$88,761
Levelized Rev Req per Adult Fish Req'd to Replace Entrained Eggs and Larvae ($/Fish)	$19,508	$47,582	$1,306	$2,018	$3,256	$6,759
20 Yr Bk Life						
NPV Rev Req ($000)	$189,361	$449,669	$109,037	$161,434	$298,398	$611,103
Levelized Rev Req ($000)	$21,225	$50,404	$12,222	$18,095	$33,448	$66,093
Levelized Rev Req per Adult Fish Req'd to Replace Entrained Eggs and Larvae ($/Fish)	$15,084	$35,819	$1,042	$1,543	$2,547	$5,033

Fish Entrainment Data

	Ormond	Mandalay	Ormond + Mandalay
# of Adult Fish Req'd to Replace Entrained Eggs	1,122	11.40	
# of Adult Fish Req'd to Replace Entrained Larvae	285	11,714	
Total # of Adult Fish Req'd to Replace Entrained Eggs and Larvae	1,407	11,725	13,133