Public Comment
Once Through Cooling
Deadline: 5/20/08 by 12 p.m.

California Council for Environmental and Economic Balance

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May 20, 2008

Jeanine Townsend, Clerk to the Board
State Water Resources Control Board
1001 'I' St., 24th Floor
Sacramento, CA 95814

RE: Comment Letter – Scoping Document: Water Quality Control Policy on the Use of Coastal and Estuarine Waters For Power Plant Cooling

Dear Ms. Townsend:

On behalf of CCEEB, thank you for once again offering us the opportunity to comment on the Board's proposed "Water Quality Control Policy of the Use of Coastal and Estuarine Waters for Power Plant Cooling." CCEEB is a non-partisan, non-profit organization of business, labor and community leaders that seek to achieve the State's environmental goals in a manner consistent with a sound economy.

CCEEB's membership includes the owners of the power generating facilities that utilize once through cooling (OTC) systems in California. As such, any state policy or regulation that proposes to phase out this coastal power plant cooling method in California is of great interest to CCEEB, particularly if the tradeoffs to the environment and the potential consequences to the economy have not been fully evaluated.

The Expertise And Knowledge Of The Inter-Agency Task Force Should Be Relied upon In The Early Development And Formulation Of This Policy

On January 16, 2008, CCEEB submitted comments recommending that the Board formulate a multi-agency process to assess and advise the state Board on the variety of multi-media impacts, outside of the Board's jurisdiction, that would result from the enactment of the proposed OTC policy. We commend the Board for forming such an advisory group. It is our belief that the expertise and skills of this group of individuals should be relied upon in the early development and formulation of this Policy.

We note that the Scoping Document refers to its role as an aid to the implementation of the Policy. CCEEB believes that this would not be the best use of this talent, and would not take advantage of the advisory body's expertise, when it is needed most as the implementation requirements are considered by the Board. We are not suggesting that the Board abrogate its authority to adopt a Policy, rather, that it consult with this group before it acts, rather than after. As stated by one of the members of the Expert Review Panel in his April 23rd written comments to the SWRCB staff, it is important not to be wrong about the real feasibility of Track 1 compliance. To do so is to underestimate the real potential of forcing these facilities to shut down in the near term, and create extreme electrical reliability issues for the state of California. It would be far better to construct a policy that acknowledges and avoids these pitfalls.

The Risk To The Stability Of The Grid Is Real

The possible negative impacts to the state's electricity grid are too critical not to warrant the highest level of concern. California ISO (CA ISO), as the entity responsible for the safe and uninterrupted flow of electricity to the grid, has expressed concern in its 2008 Summer Assessment about how California will make it through the Summer of 2008 without any serious disruptions, during just the business as usual summer cycle. Their assessment leaves very little cushion or margin for potential electricity supply shutdowns. With all generating plants running as directed and no transmission difficulties, CA ISO estimates that Southern California has only a 600MW buffer to protect it from Stage-3 Emergency blackouts. This generating capacity equates to the output of a single unit. Couple this with the fact that CalFire has already declared the official opening of the 2008 wildfire season. It would be unrealistic to believe that this summer will be totally free of wildfires that often seriously disrupt transmission capabilities and result in power outages.

The CA ISO is also conducting an in-depth analysis of grid reliability. Its Old Thermal Generation Phase I Report (2008-2012 Study Results) accounts for load growth and a range of new generation, system retirements, and facilities in the process of being repowered. It concluded "...that a Policy requiring these units to go off-line could jeopardize the CA ISO's ability to meet local, zonal and system reliability requirements, even if a considerable number of new plants come on line." It compared "current versus the new risk" of shedding firm load (blackouts) and concluded that by 2012 California would experience a four-fold increase in the risk of a Stage 3 Emergency. It also determined that "...a policy that requires these units to go off line or reduce operations could make meeting the state's 20% renewable portfolio standard more difficult than our earlier study predicts." In addition, it determined that taking the base-load nuclear plants off-line could seriously hamper the state in meeting its greenhouse gas reduction obligations. This study is expected to be completed by the 4th quarter of this year. It is essential that the Board not act on this Policy until it is informed by this study.

The staff is apparently relying upon the recently completed study by Jones and Stokes on Grid Reliability, directed by the Ocean Protection Council (OPC). This report expresses some very optimistic conclusions about the ease with which the grid can accommodate the staff's proposed OTC policy. However, the only recommendation (OPC Reliability Study, April 2008, page 6) is far more reserved and cautious:

> *"Though this study makes optimistic conclusions about the industry's ability to compensate for mass OTC plant retirements at relatively modest costs, it is extremely important to understand that the modeling effort conducted for this study was limited in scope, capable of only taking a snapshot of the big picture, due to time constraints. Ideally, the modeling effort would have been expanded to thousands of runs examining each OTC plant in great detail, instead of the limited number of runs that were possible for this study.*
>
> *Because of this limitation, the key recommendation arising from this study is that the industry must continue comprehensive study of the issue, examining the reliability implications of retirement of each plant individually and in combinations with all other plants and constantly reassess the reliability implications of the Board's new policy, as it is planned and enacted. Fortunately, such a study is now underway at the California System Operator with full participation by the state's water agencies, the energy industry, non-governmental organizations, and individuals. Cooperation amongst the agencies involved in shaping policy affecting the future reliability of the grid, including the Water Board and the energy agencies, is essential in assuring the Board's policy results in no impact to electric system reliability, nor to the environment."*

The Extent of Biological Harm is Not Adequately Nor Accurately Assessed In The Scoping Document

The statements of significant impacts from OTC systems are often centered on the high numbers of larvae that are entrained as the only evidence needed to assume that this results in significant ecological damage. However, as demonstrated by 316 (b) studies, these losses of larvae are very small fractions of the source water populations of the larvae, which are present in enormous numbers in the ocean and bays. Further, the fractional losses caused by entrainment appear to be insignificant, in virtually every case, to sustaining the adult populations of the fish relative to the levels used for fishery management, according to these 316 (b) Impingement and Entrainment (I&E) studies. Attachment 1 provides a brief discussion of this issue.

A number of the Expert Review Panel members cited in their individual responses the confusing nature of the information contained in Table 8 in the Scoping Document. This

Table presents information regarding the extent of I&E at individual facilities. It is noted in their comments that the information in the document was compiled from different sources, using different assumptions. For example, one of the Expert Panel members pointed out that the entrainment count shown in Table 8 for the Encina Power Station is over seven times the estimated annual entrainment levels reported in the most recent I&E study, completed in January 2008.

It has also been observed that the new I&E studies that have recently been completed are not cited in the Scoping Document as reference documents. This oversight leads to the question of whether the staff is familiar with these reports and has considered the information they contain.

This information is necessary to inform the Board on the true extent of biological damage caused by the operation of OTC on adult populations of affected marine organisms. The Scoping Document does not adequately, nor accurately, address these questions. For example, the January 2008 Encina Power Station I&E study found that though the number of entrained gobies was high, the adult population in the source lagoon was robust and at a higher density than adult goby populations in other lagoons without OTC. Further, the number of goby larvae present in the lagoon is the same now as it was during the 1980, 316 (b) I&E study. This consistency shows the stability of the population over time. It also demonstrates the absence of an Adverse Environmental Impact.

The Scoping Document does not demonstrate any deleterious impacts on adult fish populations. The scientific literature presented at the "Once Through Cooling Research Results Symposium" at UC Davis this past January likewise did not document any severe impacts on adult fish populations due to the operation of Once Through Cooling systems. This information is extremely significant considering that the Board is considering a Policy that will force Californians to accept alternative negative environmental impacts of more noticeable significance, face at least a four-fold greater risk of Stage 3 Emergency blackouts, and a yet-to-be determined economic penalty that the Scoping Document estimates to be between $100 million and $10 Billion.

This issue alone requires considerably more documentation to use it to support the adoption of such a costly and far-reaching public policy edict.

<u>The Scoping Document Relies Upon a Deeply Flawed Technical Feasibility Analysis, Prepared for the OPC, That Reaches Unsupportable Conclusions About The Implementation Of The Board's Proposed Policy</u>

Tetra Tech recently submitted a "technical" feasibility analysis to the Ocean Protection Council, entitled <u>California Coastal Power Plants: Cost and Engineering Analysis of Cooling System Retrofits</u>. CCEEB's review of this report concludes that while it provides some useful factual information on individual sites, many of its conclusions are not adequately supported by the information and analysis. Rather than inform and assist the Board in its deliberations, as it was envisioned, we believe that, as drafted, the report has given a misleading impression of the engineering feasibility, cost and other considerations of retrofitting the cooling systems of many of these plants. As demonstrated below, the draft report reaches simplistic conclusions of project feasibility. It ignores and/or dismisses serious physical, environmental, cost, social, and other permitting obstacles. The economic impact analysis fundamentally misrepresents power sector energy financing issues resulting in the use of unrealistic assumptions regarding plant life, amortization periods, inappropriate discount rates, and an incomplete and mistaken representation of costs and the ability to pay or recover these costs while still retaining economic viability to dispatch power. ***Since the staff has demonstrated great reliance on this document in preparation of the Scoping Document, CCEEB believes it important to bring forward a sampling of our concerns about this study.***

Feasibility

In our opinion, the primary deficiency of this document as a decision making guide is its use of the term "technically feasible" as opposed to the generally understood meaning of "feasible." Though it tries to put this term into the context of a severely constrained budget that would only allow a review of issues related to technical feasibility, the report reaches unsupportable conclusions about the ability to overcome noted obstacles such as permitting, physical location, and cost noted in the report, and ultimately determines that with few exceptions, virtually all of these plants can be feasibly retrofitted.

The report notes that any action taken to retrofit a cooling system will require a CEQA analysis. CCEEB believes that it is important that any discussion of feasibility be based upon based upon CEQA evaluation criteria (Sec. 21061.1 of the Public Resources Code):

> *"Feasible" means capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors.*

This definition represents a real world understanding of the term and includes consideration of economic, environmental, social, and technological factors when attempting to determine whether a desired end state can be accomplished in a successful manner. If this report had accomplished the breadth of these considerations and done so accurately with reasonable assurances that assumptions realistically reflected real-world conditions and decision-making criteria, then it could have been of great value in informing the deliberations of the staff and Board. However, the technical chapters make it very clear that its scope is severely limited. So limited, that no further inquiry was made after potential non-engineering obstacles had been identified. These limitations appear to have been ignored in the more general areas of the report and in so doing we believe that erroneous conclusions were reached.

The Significance of New Environmental Impacts of Retrofitting Cooling Systems Were Identified, but their Significance Was Ignored

The report did not adequately consider the **new** adverse environmental effects of converting once-through cooling (OTC) systems to wet closed-cycle cooling systems. In those situations where the report did note new environmental impacts not associated with once through cooling, the significance of such new environmental impacts were ignored and related permitting and AB 32 issues were dismissed as being beyond the scope of the study. As such, conclusions in the report relating to their significance as it might relate to determining feasibility are not supported, thereby giving a misimpression of feasibility to a third party reader, coupled with a misimpression of the significance of these new environmental impacts. We note that the Scoping Document is still very weak in this subject area as well.

New Environmental Impacts of PM10

The study noted that wet cooling towers would become new sources of particulate matter (PM10), independent of the operation of the generating station, while giving only passing reference to new NOx and greenhouse gas (GHG) emissions. The PM10 emissions, in particular, present serious permitting issues. In the South Coast Air Quality Management District (SCAQMD) there are no PM10 offsets available for these retrofits and there are only limited PM10 credits available elsewhere in the state. This means that it is likely impossible for the SCAQMD to issue necessary air permits for the new proposed wet cooling towers at the 6 generating stations operating within the district. It may be equally impossible to issue air permits for these new PM10 emissions in other locations in the state as well. The Scoping Document ignores this issue.

New Environmental Impacts Associated with the Energy Penalty of Converting From OTC to Closed Cycle Cooling

The report pointed out that there are power efficiency penalties when converting from OTC to wet or dry closed cycle cooling, but does not point out the environmental consequences of making up that lost power required for a stable grid. The report ignored the environmental impact of additional fuel consumed to make up this power. According to an analysis conducted by CCEEB[1], the statewide increase in PM10 emissions from replacing lost MWhrs would be more than 25 tons/yr if all units converted to wet cooling and 150 tons/yr if all units converted to dry cooling. The statewide increase in GHG from replacing lost MWhrs would be over 300,000 metric

[1] Attachment 2: Summary of Impacts Associated with the Retrofit of Once-Through-Cooling Systems, CCEEB, 2006 was prepared using US EPA estimates of energy penalties and increased auxiliary load associated with wet and dry cooling retrofits (dry cooling about 9%) to compute the amount of MWs that would be reduced from what can be generated from each plant presently (see Details, column V). The emissions that would be generated to replace the lost power output attributed to this energy penalty using the average output (see Details, column F) of each plant were then computed. This analysis does not predict where that replacement power would come from and instead assumes it would come from unspecified sources with emissions equivalent to the "average" NOx and PM10 emission rate for California generating units (from CEC Environmental Performance report). In reality, the replacement power would need to come from local generating sources in order to maintain grid reliability in that same region as the lost power. This average emission rate considers renewable, peaking, baseload, and all generating sources. Therefore, these emission estimates use only government backed data points to demonstrate the emissions increases to maintain the generating output levels from these plants if a wet or dry cooling retrofit were to be required.

tons CO_2 e/yr if all units converted to wet cooling and over 1.9 million tons/yr if all units converted to dry cooling. These are substantial increases in criteria pollutants and GHG. The increases in criteria pollutants represent significant permitting hurdles while the increases in GHG represents new emissions of GHG in the face of AB 32 requirements to reduce GHG emissions statewide to 1990 levels by 2020. To place some context around the GHG emissions, the 1.9 million metric tons CO_2 e/yr estimated to result from retrofitting all OTC facilities to dry cooling is equivalent to the amount of GHG emitted by almost 500,000 mid-sized passenger cars. It also represents an increase in the In-State Power Generation Sector CO_2 inventory of 4.4%.

The Scoping Document is very weak in a comparable analysis.

<u>New Environmental Impacts Associated with Retrofit Down Time of Nuclear Plants</u>

As high as these estimates of GHG and criteria pollutant impact are, it will be enormously higher if the two base-load nuclear plants have to go off-line for up to 18 months in order to accommodate the retrofits. All of the power that would otherwise be generated by the nuclear facilities, without the generation of GHG and criteria pollutants, would have to be provided by fossil fuel plants generating massive amounts of GHG and criteria pollutants.

The question of whether there is enough excess generation available to replace this lost generation during the 18 months of expected retrofit down time for each of these nuclear base load facilities also was not considered. During this same 18 consecutive month period other generating facilities may be shut down for maintenance and retrofit. If all plants had to retrofit during the same time frame the implication for adequate state power supply and to grid stability would be severe.

These issues are also not addressed in the Scoping Document.

<u>New Environmental Impacts of Salt Drift</u>

Salt drift from the seawater cooling towers was another recurring topic in the report that should have been more thoroughly evaluated to ascertain its impacts on feasibility. Even with state-of-the-art drift eliminators, which generally increase the parasitic load on the facility, the report estimated that there would be significant drift that will negatively impact agricultural and urban areas. More troubling is the drift impacting high voltage transmission lines, transformers and switching areas. The electrically conductive and corrosive nature of the drift could cause arcing and loss of power that raises grid reliability and safety issues. The report seemed to deal with these issues by assuming the other facilities would be relocated, with no examination of whether sufficient land is available.

The Scoping Document needs to address these issues in sufficient detail to support an informed decision by the Board on this Policy.

New Environmental Impacts of the Water Discharges

The report also did not adequately evaluate the new environmental issues associated with remaining water discharges. These new environmental issues arise from the 90% – 95% intake water reduction achieved by retrofitting the OTC system with a saltwater wet cooling system. The report accurately pointed out that this flow reduction will concentrate salts and other impurities in the waste stream from the cooling tower blow down. It pointed out that this concentration of impurities in the waste stream would require treatment to meet discharge-permitting requirements. In addition, the report assumed that these new wastewater treatment systems will be built at all locations without regard to land availability, assuming in all such situations that land can be purchased if needed. Furthermore, the report assumed that on-site power generation support facilities already planned to be built, would not be built and instead, that a wastewater treatment facility would be built, because the location was the only location on-site at which a wastewater treatment facility could be built. At other facilities the report assumed that site infrastructure could be relocated, either on-site or off-site. In addition, the report also failed to consider that new solid waste; brine waste and/or hazardous waste resulting from the operation of a wastewater treatment unit would have to be managed.

In order to quantify the magnitude of this potential waste stream, consider that a typical 1000MW combined-cycle generation station running on a 50-50 blend of groundwater and reclaimed water generates approximately 200 cubic yards of solid wastewater filter cake per week, in addition to a brine waste stream. Given that each of the nuclear facilities produce twice that amount of power and would be using seawater that would be 50-100 times saltier than blended water, one can see the potential for substantial quantities of waste that would be generated by retrofitting a OTC system to a saltwater cooling system. It is also likely that this new waste would fail the hazardous waste criteria thereby requiring that it be handled as a new hazardous waste stream.

Though the Scoping Document spends 15 pages on this topic it does not address how to resolve these issues, which could turn out to be a fatal flaw in to the feasibility of retrofitting to saltwater cooling towers. Again, the OPC report noted the issues, but jumped to a conclusion of feasibility.

New Visual and Noise Impacts and Mitigation

Though the study generally recognized the size and operational noise associated with wet cooling towers, it assumed that these new impacts, which are not associated with OTC, could be easily handled. In some discussions it is noted that Coastal Zone site restriction requirements proscribed in the California Coastal Zone Conservation Act could be issues or that local communities could be troubled by noise, but in only one case did the report recognize that these new impacts could not be overcome. Where zoning ordinances did not readily exist, the report noted that issues such as noise and aesthetics would be addressed under local conditional use permits. However, these considerations are not inconsequential and may also not be overcome.

If these projects were to be pursued, significant mitigation would certainly be required for the substantial new visual and noise impacts, if these obstacles did not derail permitting altogether. This additional mitigation expense was not captured nor quantified. While it is a valid argument that site-specific mitigation and therefore its permitting requirements and costs cannot be anticipated, this study once again raised difficult issues of new impacts and sidestepped their importance by stating it was outside the scope of study. This type of logic does not help inform; it leaves a false impression that serious impediments can be overcome, in every case, at trivial cost. The Board cannot side step such fundamentally important issues of feasibility. So far the Scoping Plan has addressed this issue in a minimal manner.

Engineering Challenges and Physical Obstacles Were Grossly Underestimated and/or Dismissed as Outside the Study Scope

Throughout the study, engineering and physical obstacles to retrofitting were identified, but then ignored or dismissed and feasibility was assumed. These issues can be very complex and in some cases are clearly critical issues in determining feasibility. Some of the key examples are:

Interconnection to Existing Systems: The report made many assumptions about the location of piping, connections to existing intake/outfall structures and placement of utilities underground, without consideration as to whether there was room for such facilities. Additionally, the complexity of the new piping installation was not analyzed. In one case, the study seems to accept that 4000 feet of above ground piping is desirable, technically feasible and physically possible without any significant discussion. The report provided only a simplistic view of what was involved to design, build and tie in a new cooling system to existing plumbing.

This is a fundamental difference between a requirement for a new facility and requiring a modification of an existing facility. Since the Board is considering a retrofit policy that would apply as if it were a new facility it bears a burden to anticipate and justify the added burden. The proposed policy chooses to walk the path of 316 (a) for new structures versus 316 (b) for existing structures. Congress and EPA noted this distinction, but the Scoping Plan does not address these issues or offer solutions.

Drift Abatement: Salt drift is likely to be a significant issue at many facilities –even if drift eliminators are installed. In some cases, this may involve the potential under grounding of 500 kV lines to prevent arcing and other measures to protect equipment. This issue was noted and determined to be feasible in the OPC report, but needs to be adequately assessed in the Scoping Document to ensure that is effectively considered by the Board.

Wastewater Treatment: Facilities would clearly need to build treatment facilities for the remaining discharge – which for the nuclear facilities would be on the order of 70 million gallons a day. This is a sizable discharge and the cost and complexity of building a treatment facility cannot be underestimated. Again, the OPC report assumed it could be done. The Board needs to determine if that makes sense and it should be considered in the Scoping Document.

It is also highly questionable whether there are treatment systems available to treat concentrated cooling tower blow down to the parts per billion effluent limits that would be imposed on the discharges. Because of significantly reduced flows the dilution factors will be reduced radically. With no dilution, the numerical effluent limit would become the water quality standard in the Ocean Plan (e.g. Copper = 3ppb, 6-month median).

Nuclear Regulatory Commission Requirements: When analyzing certain issues at a nuclear facility, consideration must be given to NRC license specifications. As an example, the facility's flood safety analysis may need to be revised and modifications designed due to the sitting of wet cooling towers. Once again, these issues were duly noted in the OPC report and it was assumed the NRC would not object, but the Board's Policy needs to anticipate their involvement in the Scoping Document.

Analysis of Retrofit Cost Utilized Incorrect Assumptions

The oversimplification of the engineering challenges of the feasibility of installing closed cycle cooling leads directly to a serious underestimate of the down time necessary for construction and tie-in, as well as the estimate of capital costs, replacement power and replacement power costs. In the case of the nuclear facilities, we expect down time would be on the order of 18 months – a very significant issue for critical baseload facilities. Additionally, the cost of replacement power was incorrectly calculated using a merchant generator model. For a utility, replacement power must be purchased to make up for the loss of generation. In this circumstance, there is no netting against cost savings, except for savings in fuel costs. Due to labor agreements and other issues, there are no savings in labor or other expenses when the facility is not operating.

At Diablo Canyon and San Onofre the report calculated and estimated revenue loss using an assumed wholesale electricity price of $65/MWh. This was not the correct methodology nor price of electricity to use for these base load facilities. Instead of calculating revenue loss, the report should have calculated the cost of replacement power. A fairer average cost to purchase power on the surplus market would have been the market price referent (MPR) of approximately $96/MWh. The MPR is a CPUC-set benchmark at or below which approved contracts will be considered *per se* reasonable. At this level, the lost generation cost at Diablo Canyon, for example, would be closer to $960 million, which would be offset by only approximately $66 million in fuel savings. Thus, the costs associated with lost generation due to a conversion shutdown at Diablo would be closer to $894 million assuming the 8-month period estimated by the study. However, further research indicated a shutdown in the range of 12-18 months would be required for a total cost for replacement power for Diablo Canyon in the range of $1.3 - 2.0 Billion.

Since the SONGS facility is rated at only 52MW more than Diablo Canyon, it is reasonable to expect that the costs of replacement power to be about the same. Thus the combined costs to the two utilities that operate nuclear facilities to replace power not generated during the 12 – 18 month shutdown for cooling system retrofit would be \$2.6 – 4.0 Billion.

Given that many aspects of the engineering are not thoroughly analyzed (e.g. condenser modifications, drift abatement, piping interconnections, service cooling system) it is a virtual certainty that the capital costs will be substantially higher than those projected by the study.

It does not appear that the Scoping Document is based on any independent analysis other than the OPC report. It cites costs as ranging from \$100 million to \$10 billion. That is a huge range and the costs are likely significantly understated if based upon the OPC Report. We request that all financial calculations, including assumptions and methodologies be thoroughly reviewed by the Board before moving forward with this Proposed Policy.

Economic Feasibility Analysis Was Inaccurate and Misleading

In Section 6.0, Results of the Executive Summary, the closed cycle cooling retrofit cost estimates were translated to a price per kilowatt-hour. This simple approach does not properly recognize the current market for power and power products from the plants being studied, nor does it properly consider that each facility has unique business and economic considerations that would affect the economic viability of such retrofits. CCEEB believes that any new economic analysis should be modified from that used in the OPC report to take into account the economic structure that each individual facility operates under and determine how the estimated capital expenditures will affect that facility's ability to continue to operate with marketable power products that they provide.

Many of the plants evaluated by the study did not actually obtain revenues from the energy market as described. They instead sell a capacity product to meet the electric grid's System or California's Local Capacity Requirement, also known as local Resource Adequacy (RA) contracts, which reflects the California System Operator's (CA ISO's) Applicable Reliability Criteria and approved by the CPUC. Some facilities may instead receive revenues from annual Reliability Must Run (RMR) contracts, however, this practice is being phased out and replaced with the RA approach.

System RA or local RA contracts may be year to year or may be part of a 2-5 year commitment to provide capacity in combination with other power related products (i.e. power purchase agreement), neither of which are of sufficient length to provide stable revenues to support large capital expenditures. Further, there is currently a cap on this type of capacity product of \$40/kW-year (see CPUC Decision D.07-06-029). This cap, along with the inability to obtain capacity contracts of sufficient length to amortize the significant capital expenditures contemplated by the proposed Policy, creates an infeasible economic situation to support such retrofits. The cost of the retrofit alone would likely greatly exceed the CPUC capacity price threshold not even considering the normal operations and maintenance costs to keep a facility safe and reliable. Further, the uncertain economic life of many of these plants would result in short contract terms and therefore require higher revenue requirements to make these retrofits economically viable; certainly less than the 20-year amortization assumed in the OPC report.

Not only is the 20 year amortization assumed in the report for most facilities grossly overstated, the 7% discount rate used in the report is substantially lower than currently allowed rates for utilities, in the 10% range. Independent power producers should be subject to a higher rate, but a shorter amortization period. The 3% or greater difference in the discount rate between what is typically used to evaluate capital budgeting through Net Present Value (NPV) analysis and the 7% used in the report is substantial.

The general formula used by the study that only considered the affect to wholesale energy sales, discounted these costs over a 20-year period at 7%, and compared these to 2006 actual megawatt-hours produced is not a complete nor accurate assessment of the actual cost impacts to these facilities. As such it yields misleading results.

Another significant and misleading shortcoming of the economic analysis section of the report lies with comparing incomplete computed annual operating cost to the annual revenues generated by a plant. A far more representative number against which to compare operating cost would be the gross margin of a plant. As anyone familiar with thermal plants understands that the vast majority of revenue covers the fuel cost of generation. Such a comparison would show that while annual costs may only equate to 3% of revenues for a new combined-cycle plant, these costs represent closer to 20% of gross margin, which is an enormous reduction in profitability. For older, traditional boiler plants, rather than focus on operational and maintenance costs of closed cycle cooling as 8% of revenues, it is far more instructional to realize that such costs may represent something closer to 100% or more of gross margin from energy sales.

As noted, we do not believe the Board should rely on the economic analysis provided to the OPC and staff, as we believe that it will lead to misleading results.

The Policy Should Be Based Upon A Unit-by-Unit Assessment and Not On A Staged, Firm Deadline Approach Based Upon Capacity Utilization

The policy as currently proposed, calls for a fixed phased deadline approach for conversion of these coastal generating facilities. The Scoping Document says that since many once-through-cooled power plants produce relatively little energy in comparison to their full potential and that there is a declining level of energy produced in recent years, that this indicates the units must not be necessary for electrical reliability. This is not accurate; many of these low-use units are absolutely critical for peak demand periods for grid reliability. Low capacity-utilization is reflective of its higher cost of operation. When a peaker plant is called on-line, its performance is expected and relied upon for grid reliability. As pointed out earlier, the Summer 2008 Assessment indicates that there is only a 600 MW buffer in Southern California from Stage 3 Emergency blackouts. Only the CA ISO can determine when a plant can come off line during peak periods without destabilizing the grid.

In fact, this implementation proposal with relatively early implementation dates, apparently designed by staff in the belief that it will reduce the risk of grid reliability problems, actually has the reverse effect; it increases the risk of grid problems. These units tend to be old and less economical to operate. They operate under short-term contracts and will be less likely to be able to recapture retrofit costs. Some of these units will ultimately retire without retrofit. The current proposal increases the risk that these units will be retired early as market based indicators determine financial viability, before replacement power can be built to restore essential grid services.

Each unit needs to be evaluated on its own to determine the best future course of action. The evaluation needs to be based on a site-specific evaluation of repowering or retirement options. Some of these units are old and inefficient and should be retrofitted for that reason. Instead of the current proposal CCEEB recommends that these units be individually evaluated for repowering or retirement. As a necessary component of this evaluation, CA ISO must weigh in on issues of timing and whether or not a particular site is given a "must-run" classification.

As stated in the previous section, there will likely be a tendency to continue to rely upon the Technical Feasibility report prepared for the OPC. CCEEB believes that the limitations of the report are significant and that the Board should not place weight on the determinations of feasibility as expressed in the report. As stated, we also believe that many of the calculations that were performed used unrealistic assumptions and in some cases inappropriate methodology. Similarly, we urge the Board to ignore the overly optimistic conclusions in the Jones and Stokes report prepared for the OPC. Please note though the only recommendation in that report should be followed. That recommendation is reproduced on page 3 of this letter. In essence, it recommends that the Board <u>not</u> rely on the optimistic conclusions about the ability of the grid to withstand plant closures as a result of the Proposed Policy and instead, continue to work with the CA ISO in the conduct of its considerably more thorough grid reliability study. For these reasons, CCEEB recommends that the Board wait for the CA ISO study to be completed and forestall reliance on the conclusions of the OPC-Jones and Stokes report.

Thank you for the opportunity to submit these comments; we look forward to continuing to work with you on a Policy that can be successfully implemented. If you would like to discuss this matter further, please contact Bob Lucas at 916-444-7337.

Sincerely,

Robert W. Lucas
Waste & Water Quality Project Manager

Gerald D. Secundy
President

Attachments:

1. Studies of Once-Through-Cooling Impingement and Entrainment in CA
2. Summary of Impacts Associated with Retrofit on OTC Systems

cc: Members of the State Water Resources Control Board
Dan Dunmoyer, Cabinet Secretary, Office of the Governor
Linda Adams, Secretary for CA Environmental Protection Agency
Cindy Tuck, Undersecretary, CA Environmental Protection Agency
Michael Chrisman, Secretary for Resources Agency
Jackalyne Pfannenstiel, Chairman and Members of Energy Commission
Melissa Jones, Executive Director, Energy Commission
Michael Peevey, President, CA Public Utilities Commission
Yakout Mansour, CEO, California ISO
Mary Nichols, Chair, CARB
Al Wanger, CA Coastal Commission
Paul Thayer, CA State Lands Commission
Dorothy Rice, Executive Director, SWRCB
Jonathan Bishop, Chief Deputy Director, SWRCB
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Studies of Once-Through-Cooling Impingement and Entrainment in California

Every five years the Regional Water Quality Control Boards ("RWQCB") review the NPDES permits for use of the intake water in OTC systems. Initial, and often recurring, impingement and entrainment evaluations were required at facilities utilizing OTCs in the early 1980's, which demonstrated these systems were not causing significant adverse impacts to marine ecosystems. In recent years, the interest and activities surrounding proposals for the installation of new generating technology for improved efficiency has provided a large amount of contemporary information on the effects of impingement and entrainment at the state's existing OTC intakes. A great deal more of this kind of information is also available as a result of information gathering requirements in EPA's Phase II 316(b) compliance and performance standards (see Table 1 below).

At every one of the facilities with data from previous intake studies that demonstrated no adverse impacts, the recent studies also demonstrated an absence of present day damage and found the source water communities of entrained fish and invertebrate larvae were remarkably unchanged[1,2].

Independent scientists consulting to the RWQCB made specific findings of this nature in their final review of the Moss Landing 2000 & 2001 316(b) studies of the Elkhorn Slough, Moss Landing Harbor, and Monterey Bay source water in comparing them to their own study findings from 1977, a period of nearly three decades.

The California Department of Fish & Game has stated in its Nearshore Fisheries Management Plan that an over-fished stock is one that has been reduced to 30% of its unfished biomass and that controls would need to be enacted whenever a stock is reduced to 60% of its unfished biomass. The designs of recent entrainment studies are based on similar principles of fishery management and provide estimates of the numbers of entrained organisms as a percentage of the total larvae at risk of entrainment (source water populations). In 316(b) studies of OTC systems, the entrained fraction of the source water population of larvae usually

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[1] Moss Landing Power Plant 316(b) Study

[2] South Bay Power Plant 316(b) Study

averages between 2 and 10 percent of the estimated source populations and is much lower for most species. The 2 to 10 percent average entrained fraction represents very small impacts to adult fish due to the high natural mortality of larval fishes exceeding 99.9 percent.

The statements of significant impacts from OTC systems are often centered on the large numbers of larvae that are entrained as the only evidence needed to assume that there has to be ecological damage. However, as demonstrated by 316(b) studies, these losses of larvae are very small fractions of the source water populations of the larvae, which are present in enormous numbers in the ocean and bays (see Table 1 below). Further, the fractional losses caused by entrainment are insignificant to sustaining the adult populations of the fish relative to the levels used for fishery management, especially when more than 99.9 percent of the larvae will die naturally before becoming adults with absolutely no affect on the size of the adult fish populations. For many, this scientific fact of population dynamics, which is used to regulate and assure sustainable harvests of natural populations, is philosophically at odds with their ideas of preservation.

Table 1 – Summary of Entrainment Impacts from Select OTC Studies

Facility Name	Adult Equivalent Losses as a Percentage of Adult Source Water Populations	Average Proportional Entrainment Mortality as a Percentage of Source Water Larval Populations	Study Year
El Segundo	0.10 – 0.76 %	NA	1980
Huntington Beach	NA	0.6 %	2004
Diablo Canyon	NA	8.6 %	1996-1999
SONGS	0.01 – 6.9 %	NA	1979-1986
Moss Landing	NA	13.1 %	1999
Morro Bay	NA	21.0 %	2000
Scattergood	0.001 – 0.2 %	NA	1981
Harbor	0.8 – 1.8%	NA	1981
Haynes	NA	NA	1981
South Bay	NA	13.4 %	2001

The numbers of larvae produced by most fishes during their reproductive years as adults can be enormous, but only two of those larvae need to survive to adult to maintain a stable population level. For example, a single California halibut may release as many as 50 million eggs per year over a period of greater than 20 years, and a single rockfish may release up to one million larvae per year for several years to decades depending on the species. Other species such as gobies produce only a few thousand larvae per year per adult female over a much shorter lifespan, but even in these fishes, the total lifetime survival rate required to maintain the population is less than 0.1%. The incremental losses of larvae due to OTC systems do not have any measurable effect on fish populations because they are adapted to living and reproducing in highly variable environments where the natural rates of mortality are very high and vary from year-to-year. The arguments presented by representatives of coastal resource groups ignore the role of compensation (density dependent predation and recruitment) in maintaining these populations.

On the Pacific coast, evidence showing that high numbers of entrained larvae do not result in large impacts includes the following:

- Even though gobies are entrained in greater numbers than any other fish larvae, studies at the South Bay Power Plant showed very little change in annual estimates of goby larvae entrainment between studies in 1979–1980 and studies in 2001 and 2003. The absence of any long-term changes in larval productivity is supported by abundance data on adult gobies that showed increases in the population through time from 1994-1999.
- Although recent studies at the Encina Power Station show that goby larvae are entrained in higher numbers than other fishes, studies on adult gobies in Agua Hedionda Lagoon (where the Encina intake is located) showed much higher adult densities of gobies than similar studies from Batiquitos Lagoon where no power plant is located.

Long-term monitoring in central California at the Diablo Canyon Power Plant, with an OTC volume of 2.5 billion gallons per day, showed no significant declines in nearshore fish populations over the 20 years of plant operation.

Summary of Impacts Associated with Retrofit of Once Through Cooling Systems:

General OTC Information:	
Number of Power Generation Facilities with OTC Systems:	19
Total Operating Capacity in MWs Using OTC Systems:	20,654
Percentage of CA In-State Power Generation Capacity that use OTC Systems:	45%
Range of Facility Generation Capacity Factors:	3.5% to 98%
Average Generation Capacity Factor:	25.5%
Number of Facilities Retired or with Near-Term Shutdown Commitments:	4
Percentage of OTC Facilities Where Alternative Cooling is Technically Infeasible:	67%

Impacts Associated with Retrofit to Alternative Cooling Systems:	Wet Towers	Dry Towers
Alternative Cooling Energy Penalty (Reduced Generation Capacity in MWs) Caused by Retrofit:	285	1,714
Statewide Increase in NOx Emissions (tons/year) from Replacing Lost MWhrs:	167	1,028
South Coast AQMD Increase in NOx Emissions (tons/year) from Replacing Lost MWhrs:	78	483
Statewide Increase in PM10 Emissions (tons/year) from Replacing Lost MWhrs:	27	167
South Coast AQMD Increase in PM10 Emissions (tons/year) from Replacing Lost MWhrs:	13	78
Statewide Increase in CO2 Emissions (metric tons/year) from Replacing Lost MWhrs:	311,491	1,914,837
Percentage Increase in CO2 Inventory from In-State Power Generation Sector to Replace Lost MWhrs:	0.7%	4.4%
CO2 increase to replace lost MWhrs is equivalent to CO2 from this many 4 tpy mid-size passenger cars:	77,873	478,709
Estimated Increase in Fresh or Reclaimed Water Use if Retrofit to Wet Cooling Towers (gallons/year):	20,324,422,662	-

Alternative Cooling Capital Cost Estimates (assumes technical feasibility):	Wet Towers	Dry Towers
Estimated Capital Cost to Retrofit All Operating Units to Alternative Cooling Systems:	$2,012,602,917	$2,487,753,692
Estimated Cost to Construct New Facility to Replace Lost MWs Due to Energy Penalties:	$285,037,000	$1,714,495,000
Total Estimated Costs to Retrofit with Alternative Cooling Systems & Replace Lost MW Capacity:	$2,297,639,917	$4,202,248,692

Phase II 316(b) Compliance Information:	
Required Impingement Reduction Standard	80-95%
Required Entrainment Reduction Standard	60-90%
US EPA's Calculated Capital Costs to Comply with Phase II 316(b) for CA Facilities:	$225,000,000
US EPA Cost Estimate as Percentage of Total Wet Cooling Retrofit Costs:	9.8%
US EPA Cost Estimate as Percentage of Total Dry Cooling Retrofit Costs:	5.4%
Did US EPA Find it Cost Effective to Require Retrofit to Closed Cycle Cooling in Phase II 316(b)?	NO

California Power Generation Facilities Using Once Through Cooling Systems

Facility Name	Owner	MW Capacity[14]	CW Capacity (MGD)	CW Capacity (GPM)	Approximate Capacity Factor	Dispatch Profile (peak (<10%), intermediate (10-60%), baseload (>60%)	Initial Commercial Operations	Retirement Date Commitment	Status of 316(b) Compliance	Status of State Lands Lease Renewal	EPA Phase II 316(b) Facility Cost Estimate (corrected)[16]
Alamitos	AES	1950	1275	885,417	10.0%	Peaking	1956	None	Submitted PIC; IM&E Study underway	Uncertain	
Contra Costa	Mirant	690	440	305,556	20.0%	Intermediate	1964	None	PIC due late Feb 06. Studies TBD.	Expires 2024	$2,018,600
Diablo Canyon	PG&E	2200	2540	1,763,889	98.0%	Baseload	1985	None	316(b) Study submitted in 2000.	Tidelands lease expires 2018 and discharge right of way expires 2019	$46,835,329
El Segundo 3 & 4[3]	NRG	670	398	276,389	15.0%	Intermediate	1964-1965	None	Submitted PIC; IM&E Study underway	Lease expired, renewal application complete	$15,600,838
Encina	NRG	965	857	595,139	25.0%	Intermediate	1954-1978	None	IM&E Study 95% Complete	Lease expired, renewal applications complete	$6,879,938
Haynes	LADWP	1619	1014	704,167	34.0%	Intermediate	1962-1970,2004	None	Submitted PIC; IM&E studies underway	No lease with State Lands	$5,283,933
Humbolt Bay	PG&E	0	0	0	0.0%	Retired	NA	Retired	Believed to be retired	Believed to be retired	$0
Hunters Point	PG&E	0	0	0	0.0%	Retired	NA	Retired	Believed to be retired	Believed to be retired	$0
Huntington Beach	AES	880	507	352,083	18.0%	Intermediate	1958	None	Submitted PIC; IM&E Study underway	Expires in August 2006	$6,614,078
Long Beach[4]	NRG	0	0	0	0.0%	Retired	1976-1977	Retired	Not Applicable	No lease with State Lands	$0
Los Angeles Harbor	LADWP	235	108	75,000	29.0%	Intermediate	1942-1972,1994,2001	None	Submitted PIC; IM/E studies underway	No lease with State Lands	$264,532
Mandalay	Reliant	430	255	177,083	16.0%	Intermediate	1959	None	PIC submitted; IM&E studies underway	Not applicable	$2,336,881
Morro Bay	Duke	1002	668	463,889	4.0%	Peaking	1955-1963	None	Permit renewal has schedule	Lease in trust to City of Morro Bay. Recently renegotiated.	$4,341,494
Moss Landing 6&7	Duke	1500	864	600,000	3.5%	Peaking	1969	None	Permit renewal has schedule	Lease in trust to Moss Landing Harbor District currently in negotiation	$9,044,216
Moss Landing 1&2	Duke	1036	360	250,000	55.0%	Baseload	2000	None	Permit renewal has schedule	Lease in trust to Moss Landing Harbor District currently in negotiation	
Ormond Beach	Reliant	1500	688	477,778	15.0%	Intermediate	1971-1973	None	PIC submitted; IM&E studies underway	Renewed 4/03; expires 4/17	
Pittsburg	Mirant	660	432	300,000	28.0%	Intermediate	1960-1961	None	PIC proposed later in 06. Studies TBD.	Expires 2015	$2,960,066
Potrero	Mirant	210	226	156,944	45.0%	Baseload	1965	None	PIC submitted Feb 06. E complete. I starting in Apr.	N/A. Under SF Port Authority.	
Redondo Beach	AES	1310	881	611,806	5.0%	Peaking	1954	None	Submitted PIC; IM&E Study underway	Uncertain	
San Onofre	SCE	2254	2580	1,791,667	95.0%	Baseload	1983/1984	None	Submitted PIC; IM&E to begin late Feb early Mar	Lease Expires in 2023	N/A
Scattergood	LADWP	818	495	343,750	25.0%	Intermediate	1957-1974	None	Submitted PIC; IM/E studies underway	49 year lease with State Lands started in 1980	
South Bay	Duke	723	601	417,361	25.0%	Intermediate	1960s	2008?	Submitted PIC; No Studies needed	Required plant shutdown by 2008	$143,049
Totals/Averages:		20,654	15,169	10,547,917	25.6%						$104,122,954

Notes:

1 These are GENERAL estimates; based on average wet cooling retrofit cost estimates from Jim Maulbetsch, Maulbetsch Consulting of $125/gpm for easy retrofits & $250/gpm for difficult retrofits. These estimates may not be accurate on a plant specific basis, due to specific site design situations

2 Based on San Onofre cost estimates for dry cooling retrofit equal to approximately $288/gpm of cooling water capacity; the SONGS estimate may or may not be an accurate estimate on a plant specific basis for the other OTC facilities in CA due to site specific design situations.

3 El Segundo 1 & 2 (350 MW) retired in 2003

4 Long Beach (566 MW) retired in 2004

5 Wet cooling energy penalty based on US EPA estimates provided in the Phase II 316(b) Technical Development Document for west coast facilities (Seattle), Table 5-4, page 5-4

6 Dry cooling energy penalty based on US EPA estimates provided in the Phase II 316(b) Technical Development Document for west coast facilities (Seattle), Table 5-4, page 5-5

7 Based on statewide average NOx rate of approximately 0.37 lbs/MWhr (Figure 3-5, Page 55, 2005 CEC Environmental Performance Report)

8 Based on statewide average CO2 equivalent rate of approximately 0.38 tons/MWhr (Figure 3-6, Page 56, 2005 CEC Environmental Performance Report)

9 Based on August 7, 2002 Utility Water Act Group comments to US EPA Phase II 316(b) rule development, as estimated by Shaw Stone & Webster. These estimates may not be accurate on a plant specific basis due to site design considerations

10 Percentage increase in state-wide CO2 metric tons from in-state power generation caused by OTC retrofit and alternative cooling energy penalties, based on 2002 inventory of 43.5 million metric tons (from CEC GHG Inventory Update, June 2005)

11 Assumed capital cost for adding a new natural gas fired combined cycle gas turbine plant to replace lost MWs caused by wet/dry cooling retrofit is $1000/KW

12 Based on CEC estimate for a typical 500 MW steam cycle plant with wet cooling towers operating at 90% capacity factor to use 1735 million gallons/year, reduced proportionally to average capacity factor of the OTC facilities (Table 5-1, Page 110, CEC 2005 Environmental Performance Report)

13 Based on statewide average PM10 rate of approximately 0.06 lbs/MWhr; does not include added PM10 from wet cooling tower drift (Figure 3-8, Page 58, 2005 CEC Environmental Performance Report)

14 Estimated MW capacity is based on actual remaining capacity still operating that uses OTC, imminent unit retirements are not included in total

15 Dry tower retrofit capital cost estimates based on formula found in US EPA's Phase II 316(b) Technical Development Document, Page D-4. These estimates may not be accurate on a plant specific basis due to site design considerations

16 In the Phase II 316(b) regulation, EPA provided plant specific cost estimates to comply with the performance standards based on national averages for control technology. For some facilities, EPA did not provide a cost estimate either due to confidential requests by the owner or because EPA found that the facility already met the performance standards due to existing control technology (e.g. Scattergood and El Segundo). EPA also provided a formula for estimating compliance cost based on a similar facility for those facilities without facility-specific cost estimates (e.g. El Segundo)

New water

Facility Name	Wet or Dry Cooling Feasible?	Wet Cooling Capital Cost (Easy Retrofit Estimate)[1]	Wet Cooling Capital Cost (Shaw-UWAG Estimate)[9]	Wet Cooling Capital Cost (Difficult Retrofit)[1]	Dry Cooling Capital Cost (SONGS Estimate)[2]	Dry Cooling Capital Cost (EPA Estimate)[14]
Alamitos	Possible	$110,677,083	$171,660,000	$221,354,167	$255,000,000	$191,691,589
Contra Costa	TBD	$38,194,444	$64,340,000	$76,388,889	$88,000,000	$65,839,952
Diablo Canyon	Not technically feasible	$220,486,111	$250,620,000	$440,972,222	$508,000,000	$207,624,519
El Segundo 3 & 4[3]	Insufficient Space	$34,548,611	$88,560,000	$69,097,222	$79,600,000	$59,200,805
Encina	Incompatible Land Use	$74,392,361	$109,370,000	$148,784,722	$171,400,000	$132,295,833
Haynes	Insufficient Space	$88,020,833	$132,280,000	$176,041,667	$202,800,000	$156,082,345
Humbolt Bay	NA	$0		$0	$0	$0
Hunters Point	NA	$0		$0	$0	$0
Huntington Beach	Possible	$44,010,417	$71,410,000	$88,020,833	$101,400,000	$78,519,996
Long Beach[4]	NA	$0		$0	$0	$0
Los Angeles Harbor	Insufficient Space	$9,375,000		$18,750,000	$21,600,000	$15,561,990
Mandalay	Insufficient Space	$22,135,417	$32,180,000	$44,270,833	$51,000,000	$37,097,199
Morro Bay	Incompatible Land Use	$57,986,111	$106,180,000	$115,972,222	$133,600,000	$102,365,927
Moss Landing 6&7	Incompatible Land Use	$75,000,000	$124,500,000	$150,000,000	$172,800,000	$133,382,490
Moss Landing 1&2	Incompatible Land Use	$31,250,000	$124,500,000	$62,500,000	$72,000,000	$53,242,990
Ormond Beach	Incompatible Land Use	$59,722,222	$89,760,000	$119,444,444	$137,600,000	$105,570,491
Pittsburg	TBD	$37,500,000	$152,860,000	$75,000,000	$88,400,000	$64,571,490
Potrero	Space Constraints	$19,618,056	$28,390,000	$39,236,111	$45,200,000	$32,737,730
Redondo Beach	Insufficient Space	$76,475,694	$118,500,000	$152,951,389	$176,200,000	$136,013,233
San Onofre	Insufficient Space	$223,958,333	$289,800,000	$447,916,667	$516,000,000	$201,702,064
Scattergood	Insufficient Space	$42,968,750	$72,650,000	$85,937,500	$99,000,000	$74,600,822
South Bay	Incompatible Land Use	$52,170,139	$54,860,000	$104,340,278	$120,200,000	$91,606,117
Totals/Averages:		$1,318,489,583	$2,082,340,000	$2,636,979,167	$3,037,800,000	$1,937,707,384

Facility Name	Wet Cooling Retrofit Energy Penalty (EP)[6]	Wet Cooling Lost MW Capacity - Energy Penalty[5]	Dry Cooling Retrofit Energy Penalty (EP)[5]	Dry Cooling Lost MW Capacity - Enegy Penalty[6]	Increased annual NOx tons from Wet EP[7]	Increased annual NOx tons from Dry EP[7]	Increased annual PM_{10} tons from Wet EP[13]	Increased annual PM_{10} tons from Dry EP[13]	Increased annual CO2 in metric tons from Wet EP[8]	Increased annual CO2 in metric tons from Dry EP[8]
Alamitos	1.5%	29.25	8.9%	173.55	4.7	28.1	0.8	4.6	8,833.2	52,410.1
Contra Costa	1.5%	10.35	8.9%	61.41	3.4	19.9	0.5	3.2	6,251.2	37,090.3
Diablo Canyon	1.6%	35.20	10.0%	220.00	55.9	349.4	9.1	56.7	104,174.0	651,087.7
El Segundo 3 & 4[3]	1.5%	10.05	8.9%	59.63	2.4	14.5	0.4	2.4	4,552.5	27,011.4
Encina	1.5%	14.48	8.9%	85.89	5.9	34.8	1.0	5.6	10,928.2	64,840.8
Haynes	0.4%	6.48	2.4%	38.88	3.6	21.4	0.6	3.5	6,649.3	39,895.9
Humbolt Bay	1.5%	0.00	8.9%	0.00	0.0	0.0	0.0	0.0	0.0	0.0
Hunters Point	1.5%	0.00	8.9%	0.00	0.0	0.0	0.0	0.0	0.0	0.0
Huntington Beach	1.5%	13.20	8.9%	78.32	3.9	22.8	0.6	3.7	7,175.3	42,573.2
Long Beach[4]	1.5%	0.00	8.9%	0.00	0.0	0.0	0.0	0.0	0.0	0.0
Los Angeles Harbor	1.5%	3.53	8.9%	20.92	1.7	9.8	0.3	1.6	3,087.1	18,316.7
Mandalay	1.5%	6.45	8.9%	38.27	1.6	9.3	0.3	1.5	2,921.7	17,335.7
Morro Bay	1.5%	15.03	8.9%	89.18	1.0	5.8	0.2	0.9	1,815.6	10,772.3
Moss Landing 6&7	1.5%	22.50	8.9%	133.50	1.3	7.6	0.2	1.2	2,378.2	14,110.4
Moss Landing 1&2	0.4%	4.15	2.4%	24.91	3.7	22.2	0.6	3.6	6,896.2	41,377.3
Ormond Beach	1.5%	22.50	8.9%	133.50	5.5	32.5	0.9	5.3	10,192.1	60,473.2
Pittsburg	1.5%	9.90	8.9%	58.74	4.0	23.8	0.7	3.9	7,474.2	44,347.0
Potrero	1.5%	3.15	8.9%	18.69	2.3	13.6	0.4	2.2	4,280.7	25,398.8
Redondo Beach	1.5%	19.65	8.9%	116.59	1.6	9.4	0.3	1.5	2,967.0	17,604.4
San Onofre	1.6%	36.08	10.0%	225.40	55.5	347.0	9.0	56.3	103,463.8	646,648.5
Scattergood	1.6%	12.27	8.9%	72.80	5.0	29.5	0.8	4.8	9,263.5	54,963.5
South Bay	1.5%	10.85	8.9%	64.35	4.4	26.1	0.7	4.2	8,187.7	48,580.2
Totals/Averages:	1.4%	288	8.4%	1,714	167.2	1,027.6	27.1	166.8	311,491.4	1,914,837.2

% of state GHG inventory from power generation[16] = ory from power generation[10] = 0.7% 4.4%

Cost to replace lost MWs[11] = $285,037,000 $1,714,495,000

NOx Increase In SCAQMD Area = 78.3 462.7

PM10 Increase In SCAQMD Area = 12.7 78.3

Notes:

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3
4 needed for wet cooling retrofits (gals/year)[12]: 20,324,422,682
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