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

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DYNEGY

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Via Hand Delivery
Jeanine Townsend
Clerk to the Board
State Water Resources Control Board
1001 I Street, 24th Floor
Sacramento, CA 95814

Re: Comment Letter – OTC Policy
Dynegy Comments on the Draft OTC Policy

Dear Ms. Townsend:

Dynegy Inc. (Dynegy) submits these comments on the State Water Resources Control Board's (Board) draft "Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling," June 30, 2009 (Draft Policy). These comments focus on the Draft Policy. In a separately filed letter, Dynegy also has submitted comments to the Board on the Draft Substitute Environmental Document, July 2009 (DSED), that accompanies the Draft Policy.

Dynegy has a substantial interest in the Draft Policy as it owns and/or operates three coastal power plants in California -- Moss Landing, Morro Bay, and South Bay, 3,885 MW in total -- that utilize once-through cooling (OTC) to meet the State's electricity needs. Moreover, any OTC policy adopted by the Board that addresses best technology available (BTA) will have far reaching implications for the State of California, including environmental, electric grid stability, and the economy. While we appreciate the Board's and staff's efforts to address substantively many concerns raised by the 2008 draft of the OTC policy, the Draft Policy remains flawed in several important respects. Those flaws must be resolved, and other aspects of the Draft Policy must be refined, if the Board is to adopt a viable OTC policy that achieves consistency in BTA determinations and reasonably accommodates environmental, electric reliability, and economic concerns.

Given Dynegy's recent and direct experience in addressing cooling water intake technologies and a multitude of complex OTC issues at its three California costal power plants,[1] our primary -- and continued -- concern with the Draft Policy is that it fails to account

[1] Moss Landing and Morro Bay each proposed modernization projects using OTC that -- after detailed and comprehensive review -- were approved by the State. In addition, the South Bay Replacement Project, in which

adequately for the numerous and variable site-specific considerations that determine the feasibility and impacts of cooling water intake technologies at a particular site. For example, the Draft Policy inexplicably ignores findings made in recent years through extensive California Energy Commission (CEC) permitting proceedings at Moss Landing and Morro Bay regarding not only the infeasibility of closed-cycle cooling and the absence of significant adverse environmental impact from OTC at each of those facilities, but also that closed-cycle cooling at Morro Bay would cause greater overall environmental harm than continuing the use of OTC. While the Draft Policy's revised Track I and II approach is an improvement over the 2008 draft, it is critically important that the Board provide additional flexibility that allows for consideration of all relevant site-specific considerations. Simply put, each power plant and aquatic community has unique issues that cannot be addressed by a "one-size-fits-all" BTA standard.

For the Draft Policy to be successful for the State of California, the Board must make the following changes to the Draft Policy:

- Use sound science to evaluate site-specific environmental harm of OTC and the environmental impacts of alternative technologies, including site-specific adverse environmental impacts associated with closed-cycle cooling
- Perform an environmental impact analysis that identifies the foreseeable negative environmental impacts that would result from implementation of the Policy and conduct an overall cost-benefit analysis of the Draft Policy
- Apply the wholly disproportionate standard to all units at all facilities. Failing that, clarify that the wholly disproportionate standard applies to all units at a plant with an average design heat rate of 8,500 Btu/KWhr or less
- Allow Track 2 if the plant can demonstrate that its compliance approach will achieve equivalent or lower impingement and entrainment mortality than Track 1
- Define Track 2 in terms of an achievable level of reduction in impingement and entrainment mortality to be determined by site-specific evaluation
- Revise Track 2 implementation by providing that:
  - If compliance technologies installed to meet Track 2 ultimately fall short of the compliance standard due to circumstances beyond the owner/operator's control, installation of additional controls or shutdown is not required
  - Where demonstrated, site-specific credit for entrainment and impingement survival is allowed

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Dynegy previously had a fifty percent ownership interest, proposed the use of dry cooling, but was withdrawn in October 2007.

- Where flow reduction is the sole compliance approach, impingement and entrainment studies are not required and flow reduction will be determined over an annual period

- Authorize Regional Boards to adjust compliance deadlines, as recommended by the SACCWIS, without a State rulemaking or lengthy permit proceedings

- Increase the substantive role and frequency of the CEC, CPUC and CaISO's input in implementation of the OTC policy with respect to the electrical grid reliability implications of each power plant's compliance options

- Give full credit to existing, permit-required mitigation projects that already address a power plant's OTC environmental impacts

- Prohibit Regional Boards from imposing more stringent requirements than those of the State in implementing Clean Water Act Section 316(b) (*e.g.*, require the Regional Boards to apply the wholly disproportionate standard where applicable, prohibit the Boards from accelerating implementation schedules recommended by the SACCWIS or imposing more stringent Track 1 or 2 performance standards, etc.).

In addition, as noted above, Dynegy has filed separate comments on the DSED. As currently drafted, the DSED's analysis of the environmental impacts of the Draft Policy clearly and grossly fails to meet the requirements of the California Environmental Quality Act (CEQA). Given the far reaching implications the Draft Policy will have on California, a robust CEQA analysis -- and, at minimum, a legally sufficient CEQA analysis -- is essential not only to inform the Board's decision, but also to enable other agencies and the public to understand the issues raised by the Draft Policy, to ensure the integrity of the decision-making process, and to hold the Board accountable. Before the Board adopts an OTC policy, the DSED must be significantly revised.

Our comments on the Draft Policy are presented in three sections. Section I addresses Dynegy's concerns with the overall approach of the Draft Policy. Section II presents comments on major components (*e.g.*, Track 1, Track 2, wholly disproportionate alternative) of the Draft Policy. Section III provides comments on specific sections of the Draft Policy.

I. CONCERNS WITH THE OVERALL APROACH OF THE DRAFT POLICY

A. A State-wide OTC Policy Must Be Based on Sound Science

Despite the Board's recognition that adverse impacts associated with OTC are often difficult to accurately quantify (DSED at p. 12), the Draft Policy aims to phase out the use of OTC, require expensive retrofits, or shut down existing electric generating units. Before adopting an OTC policy with such substantial impacts, the Board needs to develop sound scientific studies that determine the adverse impact of OTC on the aquatic environment and the benefits of the policy. The Board's rush to judgment without any scientific support on an issue with such far reaching implications for California is not only ill advised but also arbitrary and an abuse of discretion.

The DSED -- in absence of any scientific evidence and contrary to plant-specific CEC determinations made after extensive proceedings, including public review -- sweepingly concludes that OTC causes, without exception, unacceptable aquatic/environmental impacts at all coastal power plant locations in California. The DSED's only support for that conclusion is absolute numbers from impingement and entrainment monitoring results, numbers which apparently are presented to create the impression that OTC is solely responsible for a significant decline of marine resources in California. The Board staff's analysis is limited to the apparent reasoning that since large numbers of organisms are impinged and entrained by OTC, the adverse impacts from OTC to marine life in California must be large and, thus, a state-wide policy seeking to eliminate OTC is needed and justified regardless of any other considerations. *But see County of Amador v. El Dorado County Water Agency*, 76 Cal. App. 4th 931, 955 (1999) (CEQA "requires more than raw data; it requires also an analysis that will provide decision makers with sufficient information to make intelligent decisions.").

Beyond the absence of any real analysis, the fundamental and fatal flaw in this reasoning is that impingement and entrainment monitoring results are meaningful only in a site-specific context. The Draft Policy seeks to eliminate the use of OTC to the exclusion of all other considerations, including whether closed-cycle cooling will result in any environmental benefit or whether a power plant's OTC system is causing adverse environmental impact to the affected water body.[2] In this regard, it is worth noting that OTC has been employed at numerous locations throughout the State for decades yet there is no substantial evidence in this record of specific harm to species populations attributable to such use at any site. The reality is that species populations in locations where OTC is employed do not differ substantially from similar locations where it is not employed.[3] The Draft Policy and the DSED fail to recognize the multitude of other factors impacting the health of California's coastal ecosystem, such as over-fishing, sediment erosion, non-point source pollution from urban and agricultural areas, sewage contamination, and exotic species invasion.[4] Moreover, the Board staff has failed to demonstrate that the significant economic, environmental, and social costs imposed by its Draft Policy would appreciably benefit California's coastal and estuarine biological resources. EPRI, *supra* note 4, at vii (the empirical evidence "suggests that should use of OTC be eliminated immediately, no significant benefits to California's coastal

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[2] The Draft Policy ignores the fact that industrial use, such as cooling water, is a legally recognized beneficial use of State waters. *See* Cal. Water Code § 13050(f) (defining beneficial uses of waters of the state).

[3] John Steinbeck, Tenera Environmental, testimony at State Water Resources Control Board Public Hearing on Proposed Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (Sept. 16, 2009).

[4] *See* EPRI, *Assessment of Once-Through Cooling System Impacts to California Coastal Fish and Fisheries*, at 4-1 (Dec. 2007). All documents cited in these comments are public records that the Board should include in the rulemaking record by administrative notice. A copy of any cited document will be provided to the Board upon request.

fisheries may occur").[5]

The flaw in the Board's reasoning is demonstrated by the State of California's determinations in recent years regarding the use of OTC at Moss Landing and Morro Bay. In both cases, after exacting site-specific review, the State determined that closed-cycle cooling was neither feasible nor preferable to OTC.

1. Moss Landing

The Moss Landing Power Plant, located off Monterey Bay on Moss Landing Harbor and adjacent to the Elkhorn Slough, has utilized OTC since it commenced operation in the 1950s. In 2001, two new gas-fired combined cycle units, Units 1 & 2, were brought on-line. These new units, in combination with existing Units 6 & 7, make Moss Landing the largest power plant in California in terms of electrical generating capacity, yet both generating blocks (Units 1 & 2 and Units 6 & 7) have among the lowest cooling water flow-to-MWh ratios of the California OTC power plants (see DSED, Figure 11, at 38).

In the NPDES permitting of new Units 1 & 2, the Central Coast Regional Water Quality Control Board (Central Board) required new entrainment studies to determine the impacts that could be expected from the operation of the new units. Those entrainment studies were performed under the direction of a technical working group that included Central Board staff and their independent technical experts, including Dr. Greg Cailliet, Moss Landing Marine Laboratories, and Dr. Pete Raimondi, University of California, Santa Cruz, both of whom are members of the Board's Expert Review Panel regarding the proposed OTC Policy. The studies found that 13 percent of the fish larvae in the Elkhorn Slough/Moss Landing Harbor are at risk of entrainment from operation of the new units.[6]

The Central Board staff and their independent scientists determined the OTC impacts at Moss Landing warranted mitigation, but were not so significant as to require installation of one of the other numerous alternative cooling or flow-reduction technologies that had been evaluated. In the 2003 *Staff Report*[7] for the Moss Landing NPDES permit, the Central Board staff explained that the impacts from OTC cannot be reliably translated into impacts to adult fish populations and, further, that eliminating OTC at Moss Landing is unlikely to result in discernable changes to the populations of fish in Elkhorn Slough and Moss Landing Harbor. Specifically, the *Staff Report* quotes an independent study showing that the population of several species of fish in Elkhorn Slough has been stable or increasing over the past several

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[5] The EPRI study, *supra* note 4, at p. 5-1, further concludes that, "The [Board] has not provided any quantitative technical information to support the nature of the fishery improvements that would be achieved by the [Draft Policy] despite the availability of a significant amount of recently collected and existing data documenting the magnitude of impingement and entrainment losses."

[6] The CEC also concluded that impingement impacts from Moss Landing Units 1 & 2 would not be significant. Commission Decision, Application for Certification Moss Landing Power Project, Docket No 99-AFC-4, Finding 12, at 188 (Nov. 2000).

[7] California Regional Water Quality Control Board Central Coast Region, *Staff Report,* Duke Energy Moss Landing Power Plant, Units 1 and 2, Review of Finding No. 48, NPDES Permit Order No. 00-041 (Apr. 10, 2003).

decades while Moss Landing has been in operation:

> Since the 1970s, the abundance of both juvenile and adult fishes in Elkhorn Slough has decreased somewhat. However, in general, the species composition and overall densities of the dominant fish larvae appear to have remained fairly similar, with some species of fish larvae being considerably more abundant in 1999-2000 than in previous decades. The main categories of fish larvae exhibiting higher densities were gobies, the Pacific herring, Pacific sand lance, staghorn sculpin, white croaker, true smelts, and blennies.

Staff Report, supra note 7, at 13. The entrainment study for Moss Landing determined that six fish species made up 95 percent of all the fish subject to entrainment by the power plant: various gobies (87% of entrained larvae); Pacific staghorn sculpin (2%); White croaker (2%); Blennies (2%); Pacific herring (1%); and Longjaw mudsucker (1%). In other words, *five of the six fish species most at risk for entrainment -- and representing 94 percent of all the fish species entrained by the power plant -- have actually increased in abundance over the past several decades* during which Moss Landing has operated using OTC. Although the independent study did find that the populations of two species of fish (*i.e.*, longjaw mudsucker and northern anchovy) appear to have declined over the past three decades, the study concluded that those changes appear to be habitat-related, and *not* due to Moss Landing's OTC system:

> Thus, the main reason for these changes in the Elkhorn Slough fish assemblages is erosion and the subsequent shifting of sediment, which has influenced the ability of certain fishes to feed and successfully spawn and produce larvae or for immigrating larvae to survive in waters that may be increasingly turbid and fast moving.

Staff Report, supra note 7, at 13. Moreover, after acknowledging the difficulty of linking population effects to impacts from Moss Landing, the *Staff Report* (at 14) concludes that:

> Even if one assumes that [Moss Landing] has contributed to the potential decline in longjaw mudsucker and northern anchovy larval species, the assumed benefit would then be an increase in these larval species if closed cooling were implemented. However, it is difficult to conceive a scenario in which potential increases in these two larval species could possibly justify the costs of closed cooling alternatives.

In short, the Central Board staff and their independent experts reviewed the site-specific data and concluded that, while the loss of larvae from the use of OTC at Moss Landing was by itself an impact, the impact was insufficient to warrant the use of alternative cooling or flow reduction technologies. The Central Board relied on that conclusion to require Moss Landing to fund $7 million in habitat restoration projects aimed at improving habitat quality and area for the species most at risk for entrainment. Importantly, those habitat restoration projects, which have been fully funded and are being implemented, address entrainment impacts from Moss

Landing Units 1 & 2 over the entire duration of the plant's operational life. Thus, any additional restrictions on OTC use at Units 1 and 2 are unnecessary and inappropriate, and the Draft Policy must expressly give full credit to plants that have already addressed OTC impacts.

2. Morro Bay

Morro Bay has utilized OTC since the plant began operations in the 1950s. In 2004, the CEC approved a modernization project at Morro Bay that would replace four units with two combined cycle units, finding that reuse of the existing OTC system in the modernization project would have no significant adverse environmental impact on aquatic biological resources.[8] Specifically, the CEC's Conclusions of Law included the following:

- "Modernization of the Morro Bay Power Plant with reduced use of once-through cooling and the Conditions of Certification proposed herein *will not cause any significant, direct, indirect or cumulative adverse impacts* within the meaning of CEQA."

- "There is no need to consider alternatives to once-through ocean cooling pursuant to CEQA because *such cooling will not have a significant, adverse environmental impact* pursuant to CEQA."

- "Modernization of the Morro Bay Power Plant with reduced use of once-through cooling and the Conditions of Certification proposed herein will comply with all applicable laws, ordinances, regulations and standards including, but not limited to, sections 316(a) and 316(b) of the Federal Clean Water Act."

Morro Bay Power Plant Project, 3rd Revised Presiding Member's Proposed Decision, Findings 1, 2, and 4, at 323 (June 2004) (emphasis added) (Morro Bay 3rd RPMPD).[9] While the CEC found that the modernized plant would have a potential adverse impact (*i.e.*, 16.2 percent mortality to larvae species affected by entrainment), the CEC determined that such an impact was "environmentally protective ... given the continued abundance of larvae in Morro Bay notwithstanding 50 years of plant operations." *Id.* at 321, Findings 30-31.[10] Moreover, the CEC expressly found that closed-cycle cooling at Morro Bay would cause greater overall environmental harm than continuing the use of OTC. *Id.* at 353, Finding 27.

In short, the Draft Policy's premise regarding indiscriminate significant environmental

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[8] The CEC approved Morro Bay's Application for Certification on August 2, 2004 (Docket No. 00-AFC-12). The Decision has not yet been filed with the Docket Unit.

[9] The CEC Adoption Order dated Aug. 2, 2004, *supra* note 8, incorporates the Morro Bay 3rd RPMPD.

[10] The CEC noted that "massive mortality of the vulnerable larvae is normal, whether the power plant exists or not", Morro Bay 3rd RPMPD at 309, and concluded that "the record is clear that even without operation of the existing or proposed new power plant, the Morro Bay Estuary is on a path of rapid decline, largely due to sedimentation." *Id.* at 4. Impingement impacts from the modernized plant were found to be not significant. *Id.* at 319, Finding 9.

harm from OTC is not supported by the State's own site-specific assessments at Moss Landing or Morro Bay. Nor has the Board supported its rationale for the Draft Policy with a sound scientific basis demonstrating state-wide adverse environmental impact from OTC or benefit from implementation of the Draft Policy. Full consideration of site-specific empirical evidence is needed. Without it, the Draft Policy is fatally overbroad and arbitrary.

B. The Draft Policy is Misguided in Certain Key Respects

1. Section 316(b) and CEC Policy Do Not Support Elimination of OTC Plants

The Draft Policy's effect, if not its express purpose, is to force the replacement, repowering or retirement of existing OTC power plants. Neither Clean Water Act Section 316(b) nor the CEC's policy on aging power plants supports that result or intent.

The stated purpose for the Draft Policy is the State's need to implement Clean Water Act Section 316(b) in light of the continuing absence of national uniform performance standards under Section 316(b). Section 316(b) does not, however, require elimination of OTC or favor repowering of existing OTC facilities. It simply requires that cooling water intake structures reflect BTA. Thus, Section 316(b) does not support the Draft Policy's aim to eliminate existing OTC facilities.

Nor do the CEC's recommendations regarding orderly retirement or repowering of aging power plants, originally articulated in the 2005 Integrated Energy Policy Report (IEPR), support an OTC policy that seeks to eliminate OTC plants because of their environmental impacts. Rather, the CEC's policy explicitly supports the modernization of aging plants, recognizing that, in the absence of transmission upgrades, existing OTC plant sites are needed for modern power plant generation to serve local reliability needs (*see, e.g.*, the CEC's 2007 IEPR recommendation that the CPUC "[r]equire investor-owned utilities to procure enough capacity from long-term contracts to allow for the orderly retirement *or repowering* of aging plants by 2012.").[11] Indeed, in recent years the CEC approved modernization projects at both Moss Landing and Morro Bay that involved continued use of once-through cooling after hearing much more extensive scientific evidence regarding the impact of OTC and the feasibility of alternative cooling systems than the Board has considered in this proceeding.

2. An Overall Cost-Benefit Analysis of the Draft Policy is Needed to Avoid Irrational Results

Given the far reaching implications of the Draft Policy's reliance on imposition of closed-cycle cooling as BTA under Section 316(b), Dynegy strongly believes that the Board should conduct a program level cost-benefit analysis. In light of the United States Supreme Court's decision upholding cost-benefit analysis under Section 316(b), it is imprudent for the Board to determine BTA in the absence of any attempt at conducting an overall cost-benefit

[11] California Energy Commission, *2007 Integrated Energy Policy Report,* at 7 (emphasis added).

analysis. Without that analysis, the Board cannot make a reasoned decision and the public and other agencies cannot meaningfully understand the impacts of the Draft Policy. Without that analysis, imposition of closed-cycle cooling as BTA is arbitrary.

The concern with the Board staff's drive to impose closed-cycle cooling as BTA in the absence of an overall cost-benefit analysis is readily apparent in light of the cost-benefit analysis of the Draft Policy prepared by NERA Economic Consulting (NERA) for the California Council for Environmental and Economic Balance (CCEEB).[12] NERA's conservative analysis based on data taken directly from the Board's own consultant (Tetra Tech, *infra* note 13) concludes that the costs of the Draft Policy ($3.12 billion) exceed its benefits ($34.2 million) by 91 times. The Board cannot simply ignore the economic impacts of its proposed OTC policy. Dynegy strongly urges the Board to conduct an overall economic analysis of it proposed policy and revise the proposed policy to appropriately account for the results of that analysis.

3. The Draft Policy is Premised on an Incorrect Understanding of the Financing Process Needed to Repower or Retrofit an OTC Plant

The Draft Policy fails to account for the fact that most of the affected OTC plants are owned by independent power producers (IPPs) who, unlike utilities, have no assured recovery of investment via rate base treatment. Additionally, the Board's reliance on the long-term procurement process (LTPP) fails to recognize the substantial inadequacies of the LTPP.

For many of the older, low capacity factor OTC plants, capital investment on the scale required to accommodate a retrofit with alternative cooling technology or repowering cannot be economically justified. Without a source of revenue to cover the level of investment in a cooling system retrofit, many of these IPP OTC plants will be retired. In order to repower a facility that would otherwise be retired, a generator must secure a contract for the replacement plant that is sufficient in term and price to allow for an appropriate return on the generator's investment in the repowered plant. However, the current LTPP is inadequate to deal with the number of facilities being retired, retrofitted or repowered. The LTPP is not transparent, repowering or replacement projects are not given due consideration, and all of the costs and benefits of proposed projects are not considered. A reformed procurement process is needed to provide contracts for new generation and retrofits. First preference should be given to the owners or operators of OTC facilities that are being forced out of business.

Reforms to procurement practices would be needed to make repowering or retrofits of OTC plants possible. Of paramount importance, any request for offer (RFO) process must be structured such that repowered projects can compete on a level playing field with other alternatives, such as transmission lines or generation in other locations. Necessary reforms to the typical RFO process would include:

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[12] NERA Economic Consulting, *Preliminary Costs and Benefits of California Draft Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling* (Sept. 2009).

a. Repowered Plants Must Be Offered a Contract Term that is Similar in Duration to the Economic Life of Utility Self-build Options

New generation is capital intensive. Traditionally, the useful life of generation or transmission is considered to be 30 years or more, and utilities depreciate such large capital expenditures over the useful life of the asset, yielding an annual rate of recovery that is moderate. However, when IPPs respond to utility RFO's, IPP's are typically required to agree to contract terms of 10 years. It is also common that newly constructed power plants are unable to find contracts for capacity beyond the initial term of their contract. No structured capacity market exists, and existing units are often disqualified from participating in "new source" utility RFO's, even when utilities seek contracts for incremental supply (*i.e.*, Why buy the cow when the milk is free?).

Faced with this construct, IPPs must either seek to recover the bulk of their investment within the term of the contract, which makes their bid into RFO's appear expensive relative to utility self-build options, or chance recovery of a significant portion of their investment from the energy market post-contract. Dynegy's experience is that capital markets are unwilling to finance new power plant projects that rely upon earnings beyond the initial term of the contract with the utility. For this reason, the terms and conditions associated with a contract for a repowered facility should be comparable to those conditions under which utilities might pursue alternative investments. Otherwise, the evaluation process skews the true cost to the ultimate consumer.

b. Transmission Project Evaluations Must Recognize the All-in Cost of Replacing a Retiring Plant

Existing OTC plants not only provide local reliability benefits, but also supply important adequacy benefits and renewable power integration benefits. When evaluating the appropriate means of replacing a resource, it is important that the replacement facility truly replicate all of the benefits of the retiring plant deemed important by the ISO. If the benefit to be replicated is solely local reliability, a transmission only solution may (or may not) meet the need. If the need is resource adequacy and/or renewable power integration, incremental transmission is insufficient to meet the need unless it accesses truly incremental, uncommitted generation resources. Dynegy is currently unaware of any regions in the west that have large surpluses of generating resources waiting for market access. Incremental transmission most likely provides solutions only when coupled with the new, incremental generation required to fill the line. In such situations, evaluation of alternatives to on-site replacement generation must include the costs of both transmission and new generation for the evaluation to be valid. Transmission solutions must also account for other costs associated with displacing local generation, such as the cost of local reactive power support and increased transmission losses.

c. The Benefits of On-site Repowering Must be Considered

Alternative evaluations must recognize that the environmental impact of reutilizing an existing industrial site will be less than the siting and construction of new greenfield facilities. In many cases, repowering of existing plants would reduce local air emissions, result in little to no incremental visual blight, and reduce noise levels, in addition to conserving otherwise open spaces. All of these considerations suggest that repowering projects may possess advantages in the new-plant siting process over greenfield projects elsewhere in the State. Additionally, several of the plants jeopardized by Draft Policy are located in small, rural communities in which the plant comprises a major component of local tax revenues and employment. Loss of these plants would eliminate the single largest employer in these towns and further stress the budgets of these communities, such as Morro Bay and Moss Landing.

Repowering project approval would also sustain the continued presence in California of several IPPs that otherwise will be damaged commercially to a material extent by the closure of much, if not all, of their California portfolios in response to the Draft Policy. The continued presence of IPPs in California will provide generation service benefits to the State's consumers that are unique to the IPP industry and unlikely to be replicated by utility owned generation (*e.g.*, lower facility cost, lower cost of operation, willingness to accept operational performance risk, greater unit availability, etc.).

4. Regional Boards Should be Expressly Prohibited From Imposing More Stringent Section 316(b) Requirements Than Those Adopted in the State's OTC Policy

The Draft Policy should expressly prohibit Regional Boards from imposing more stringent requirements than those of the State in implementing Clean Water Act Section 316(b). For example, Regional Boards should not have the authority to impose more stringent Track 1 or 2 performance standards or ignore application of the wholly disproportionate standard to qualifying facilities. Nor should the Regional Boards have the authority to accelerate implementation schedules recommended by the Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS). Without such an express prohibition, electric grid reliability as protected by implementation of SACCWIS compliance scheduling will be jeopardized, OTC facilities will lack the certainty needed for compliance planning, and statewide consistency in implementation of Section 316(b) – one of the Board's stated purposes for adopting the Draft Policy -- will not be achieved.

5. The Draft Policy's Failure to Provide All OTC Plants a Site-Specific Cost-Benefit Analysis for Determining BTA is Arbitrary, Capricious and an Abuse of Discretion

With the exception of the very few OTC plants that may be able to avail themselves of the Draft Policy's wholly disproportionate demonstration alternative (*i.e.*, units with a heat rate of 8,500 Btu/KWhr or less), the Draft Policy would determine BTA without any consideration of site-specific costs and benefits. In *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. __, 129 S. Ct. 1498 (2009), the United States Supreme Court held that that cost-benefit analysis is permissible in making BTA determinations under Clean Water Act (CWA) Section 316(b).

While CWA Section 316(b) may not require that BTA determinations consider site-specific cost-benefit analyses, the Board's decision to preclude consideration of site-specific costs and benefits in determining BTA for almost all OTC plants is unreasonable, arbitrary, capricious, and an abuse of discretion. *See, e.g., Stauffer Chemical Co. v. Air Resources Control Board,* 128 Cal. App. 3d 789, 796 (1982) (agency's quasi-legislative rulemaking action subject to judicial review to determine whether it is arbitrary, capricious, or entirely lacking in evidentiary support).

Given the documented high costs of BTA technologies (*see, e.g.,* Tetra Tech *infra* note 13) and site-specific determinations by the State in recent years that OTC did not have significant adverse environmental impacts requiring replacement of OTC (*e.g.*, Moss Landing and Morro Bay as discussed I.A. above), adopting an OTC policy that outright prohibits consideration of site-specific costs and benefits is inherently unreasonable. Such a policy will impose the absurd result of installing closed-cycle cooling at extreme cost where there is no or de minimis environmental benefit from installing such technology. Moreover, the Board's justification for the Draft Policy is entirely lacking in support given its failure to develop scientific support regarding the adverse impacts of OTC. In short, consideration of site-specific cost-benefits is not only permissible in determining Section 316(b) BTA, but also necessary to include in any OTC policy adopted by the State to avoid unreasonable and arbitrary and capricious Board action.

II. CONCERNS/COMMENTS ON MAJOR COMPONENTS OF THE DRAFT POLICY

A. The Draft Policy Must Allow Greater Flexibility to Achieve Site-Specific Solutions Rather Than Imposing a One-Size-Fits-All Solution

Each power plant is unique in its design, location, and operation and each aquatic environment is unique and highly variable. The performance of any individual cooling water intake technology (*e.g.*, aquatic filter barrier, fish returns, wedgewire screens, behavioral devices) also can vary greatly depending on site-specific factors.[13] Thus, the interaction of a power plant's OTC system and its local environment is highly site specific. Accordingly, any state-wide OTC policy must be designed to allow for site-specific considerations in all appropriate instances. The failure to do so will have numerous and significant adverse impacts, including greater overall harm to the local environment and potentially no benefit or even greater harm to the specific water body intended to be protected.

While the Draft Policy is an improvement over the 2008 draft OTC policy, additional flexibility is needed to address each OTC-power plant's unique issues that dictate how or if it can best comply with new requirements aimed at reducing the use of OTC. The Board's desire for state-wide consistency in implementing 316(b) does not conflict with the need to recognize site-specific factors. Rather, within the context of a state-wide OTC policy, the State -- the

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[13] Tetra Tech, *California's Coastal Power Plants: Alternative Cooling System Analysis,* at I-19 and J-35 (Feb. 2008).

Board, together with the energy agencies and other relevant agencies -- should work to create site-specific solutions.

As currently written, the Draft Policy precludes site-specific solutions as it would essentially force each OTC plant to either retrofit with closed-cycle cooling (Track 1) or shutdown, or, where Track 1 is determined by the Regional Board to be "not feasible" (an undefined term), achieve a "comparable level" of reduction (Track 2) in impingement and entrainment to that achieved by closed-cycle wet cooling (*i.e.*, within 10 percent of the reduction achievable under Track 1). That one-size-fits-all standard -- achieve closed-cycle reductions or, at the Regional Board's discretion, achieve a level of reductions comparable to wet closed-cycle cooling -- will not work.

1. A Wholly Disproportionate Alternative is Necessary and Appropriate But, As Drafted, Must be Revised or Clarified in <u>Several Important Respects</u>

Dynegy strongly supports the inclusion of a wholly disproportionate alternative. The alternative standard is needed to accommodate site-specific flexibility. Moreover, the United States Supreme Court upheld the wholly disproportionate cost test in determining that cost-benefit analysis is permissible under Clean Water Act Section 316(b). *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. __, 129 S. Ct. 1498 (2009).

a. The Board Should Expand Applicability of the Wholly <u>Disproportionate Alternative to All OTC Plants</u>

Dynegy supports expanding applicability of the wholly disproportionate alternative to all OTC plants, and not, as currently drafted, limiting it only to those plants with generating units with a heat rate of 8,500 BTU/KWhr. Given the lack of site-specific considerations under Track 1 and the near absence of site-specific considerations under Track 2, a workable alternative for making Section 316(b) BTA determinations at all OTC plants is necessary and appropriate. It is particularly needed as a possible compliance alternative for those OTC plants for which both Track 1 is not feasible and the Track 2 minimum performance standard is approachable but not attainable.

b. If a Heat Rate Criterion is Retained, The Wholly Disproportionate <u>Standard Must Apply to All Units at a Plant</u>

Assuming the Board does not make the wholly disproportionate alternative available to all OTC plants, the Board must clarify the language of the Draft Policy's 8,500 Btu/KWhr wholly disproportionate provision to state clearly that the alternative applies facility-wide, and is not limited only to an individual unit(s) at the facility. In other words, the wholly disproportionate alternative should apply to all units at a plant that, in the aggregate, have an average heat rate of 8,500 Btu/KW or less. As currently drafted, this provision may exclude the most efficient steam boiler units that are capable of providing load following services necessary to meet California's renewable energy standards. Specifically, Moss Landing's steam boilers (Units 6 & 7) have the ability to ramp up at a rate of 30 MW/minute (from 200 MW to 730 MW), which is significantly faster than the new combined-cycle combustion gas turbine generation (Units 1 & 2), which can ramp up no faster than a rate of 20 MW/minute (from 290 MW to 510 MW). Units such as Moss Landing 6 & 7 will be needed to help California meet a 33 percent renewable standard because the rapid ramping characteristics allow them to quickly adjust energy output to the grid when power generation falls off and picks up from less predictable wind and solar renewable sources.

c. <u>"Heat Rate" Must be Defined</u>

In the event a heat rate value is retained as the criterion for applicability of the wholly disproportionate alternative, the Board must clearly define the term "heat rate". Dynegy recommends that "heat rate" be defined as higher heating value (HHV) at designed maximum sustainable capacity. Utilization of the design heat rate is appropriate to avoid issues regarding determination of actual heat rate.

d. Regional Boards Must be Required to Apply the Wholly <u>Disproportionate Alternative</u>

As currently drafted, the Draft Policy provides that a Regional Board "may consider" a facility's request to establish a BTA standard using a wholly disproportionate demonstration. The Board must revise that language to make it clear that a Regional Board must apply the wholly disproportionate evaluation for all qualifying facilities. The Regional Board must not have the discretion to ignore the wholly disproportionate alternative. Doing so would essentially render this needed alternative meaningless.

2. <u>Track 1 is Infeasible for Many Plants</u>

Reducing intake flow and velocity to a level equal to that which can be attained in a closed-cycle cooling system will not be feasible at many of the OTC power plants. Indeed, in recent years State of California permitting authorities have rejected closed-cycle cooling at Moss Landing (Units 1 & 2) and Morro Bay as infeasible for numerous reasons. More specifically:

<u>Lack of PM_{10} Emission Reduction Credits (ERCs) Needed for Wet Cooling</u> -- At Moss Landing and Morro Bay, there are not enough PM_{10} ERCs in the respective air permitting jurisdictions to meet the air permit requirements needed to install and operate wet cooling systems.

At Moss Landing, analysis at the time of the NPDES permitting of Units 1 & 2 demonstrated that the quantity of PM_{10} ERCs required to cover the additional PM_{10} emissions associated with wet cooling for just Units 1 & 2 exceeded the total inventory of all PM_{10} ERCs in the Monterey County Unified Air Pollution Control District.[14] That is still true today. Based on the Tetra Tech study[15] wet cooling towers at Moss Landing would increase PM_{10} emissions by 381 tons per year. However, the current total inventory of PM_{10} ERCs in the Monterey Bay Unified Air Pollution Control District emissions registry is only 183 tons.

At Morro Bay, wet cooling towers -- assuming for the sake of argument that wet cooling was feasible, an assumption that directly contradicts the CEC's finding of infeasibility -- would increase PM_{10} emissions by 178 tons per year (Tetra Tech, *supra* note 13, at Table I-6),[16] but the total inventory of PM_{10} ERCs in the San Luis Obispo County Air Pollution Control District emissions bank is currently only 31 tons.

Even if Dynegy were successful in purchasing all currently available PM_{10} ERCs and all other criteria pollutant credits allowed to substitute for PM_{10} (an implausible scenario), there would be insufficient ERCs to support the wet cooling projects making them infeasible. Because each of the California OTC facilities identified in the DSED is located in a designated nonattainment area for PM_{10} (Tetra Tech, *supra* note 13, at p. 3-12), the availability of PM_{10} ERCs is potentially a critical feasibility issue for each plant.

The Board's own consultant's (Tetra Tech) did not take into account the unavailability of PM_{10} ERCs in its analysis of the feasibility of closed-cycle cooling:

> Considerations outside this study's scope may limit the practicality or overall feasibility of a wet cooling tower retrofit at Moss Landing.
>
> Depending on capacity utilization, cooling tower PM_{10} air emissions could result in a significant increase in the facility's total emission profile and may conflict with Monterey Bay Unified Air Pollution Control District air permit regulations, thereby requiring emission offsets or credits. If available, emission credits could add substantial cost to the overall total, if these credits are available in sufficient quantity.

Tetra Tech, *supra* note 13, at J-3.[17] Similarly, for Morro Bay, Tetra Tech concluded that, "a

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[14] Testimony of Duke Energy Moss Landing LLC, State of California, Regional Water Quality Board, Compliance with Remand of a Portion of NPDES Permit Re Cooling Water Intake of New Units 1&2, NPDES Permit No. CA0006254, at 58-60 (2003).

[15] Tetra Tech, *supra* note 13, at Table J-9.

[16] Morro Bay 3rd RPMPD at 328 (recognizing that the Morro Bay area contains insufficient emission offset credits to compensate for saltwater drip particulate that would come from salt water cooling towers).

[17] Additionally, the Board ignores EPRI's finding that retrofitting Moss Landing Units 6 and 7 is uneconomical: "On balance, it is concluded that the nature of the likely problems and additional costs to be encountered at MLPP would put the retrofit at this site in a 'more than average' difficulty category even though the more site-specific estimate from [Duke Energy North America] corresponds reasonably well to the 'average' costs from the survey. Based on the results from the Maulbetsch Consulting survey presented above, this would put the project cost in the range of $80 to $90 million for Units 1 and 2 alone. If Units 6 and 7 were to be included, it would add $200 to $250 million to the cost which, for units with such low capacity factors, is uneconomical." EPRI, *Issues Analysis*

potential concern exists over the ability of a retrofitted MBPP to meet the PM_{10} emission goals established by the San Luis Obispo Air Pollution Control District, principally due to the increased emission from the towers themselves." *Id.* at I-1.

Local Ordinances Prohibiting Cooling Towers -- At Morro Bay, dry and hybrid (wet/dry) cooling were found to conflict with the City of Morro Bay's zoning policies and plans. Morro Bay 3rd RPMPD at 339. The CEC also expressly rejected wet cooling as infeasible at Morro Bay due to its "serious noise and visual impacts" and that it "could not meet local noise standards". *Id.* at 328. In addition, during the CEC permitting of the modernization project, the City actively opposed the use of any technology but OTC. Indeed, the City adopted several resolutions opposing dry and hybrid closed-cycle cooling systems and testified that it would not permit the plant to obtain the site control that was needed for construction of a dry or hybrid cooled plant. *Id.* at 339-348.

Site Restrictions -- The City of Morro Bay testified in the CEC proceeding that it would not permit the Morro Bay power plant to obtain the land access that was needed for construction of a dry or hybrid (wet & dry) cooling system. Morro Bay 3rd RPMPD at 337-338. Moreover, the CEC recognized that the necessary space may not be available on site to install dry cooling. *Id.* at 350, Finding 10. At Moss Landing, sufficient space may not exist to employ dry cooling for Units 6 & 7. EPRI, *supra* note 17, at App. B.10 (for Moss Landing Units 6 & 7 "[t]here is no available space close enough … to install an air-cooled condenser with a reasonable steam duct length").

Salt Drift -- Salt drift from wet cooling towers would likely impose substantial maintenance burdens for all equipment around a power plant. This would be especially true at Moss Landing. Because Moss Landing is not within an enclosed building, the corrosive effects of this additional salt drift on the infrastructure would pose a material maintenance problem and expense and, in particular, could cause arcing in the adjacent PG&E switchyard, which is a critical grid reliability infrastructure. Even with PM_{10} suppression technologies employed on the cooling towers, 466 tons of particulate -- primarily sea salt -- are anticipated to migrate off-site each year. This is over five times the amount of PM_{10} emissions currently produced by the plant. In addition, Moss Landing is located in the midst of prime agricultural land. The accretion of this much salt on agricultural land raises serious concerns regarding potential detrimental impact on the fertility of this land and its agricultural production. *See* CEC Decision, *supra* note 6, at 159-160 (rejecting sea water cooling, in part, due to "saltwater drip impacts to agriculture"). At Morro Bay, the CEC rejected salt water wet cooling, in part, due to concern about salt drift from the cooling tower. Morro Bay 3rd RPMPD at 328.

Lack of Recycled Water -- The quantities of available recycled or freshwater at Moss Landing and Morro Bay are insufficient to cover each plant's respective need. Morro Bay 3rd RPMPD at 349, Finding 3 (concluding that freshwater is not reasonably available at the Morro Bay site for wet or wet/dry hybrid cooling); *Staff Report, supra* note 7, at 10 (freshwater cooling

of Retrofitting Once-Through Cooled Plants with Closed-Cycle Cooling: California Coastal Plants, App. *B.10* (Oct. 2007).

towers are unavailable for Moss Landing because very little freshwater is available in the area). Moreover, any effort to require recycled water, in whole or in part, would impose very significant increases in operating costs, and would introduce a dependency beyond the control of the plant that would potentially jeopardize its availability and reliability.

3. The Track 1 Minimum 93% Reduction Requirement is Arbitrary

The Track 1 performance standard -- a "minimum 93 percent reduction in intake flow rate" -- is arbitrary. The Board has offered little support for, let alone substantial evidence, that this standard is either necessary for achieving environmental benefits or achievable at all OTC facilities using closed-cycle cooling. The DSED justifies the 93 percent minimum standard based on a study prepared for the Board by Tetra Tech and an EPRI report. However, both the Tetra Tech and EPRI reports are initial analyses using approximations and assumptions that are not based on the detailed engineering required to determine the actual flow reductions achievable at each facility. Indeed, the EPRI report relied on by the Board states that, "[t]he problems to be overcome, the resultant project costs and the effects on plant performance are highly site-specific."[18] The Tetra Tech report itself only includes facility profiles for 15 of the 21 California OTC facilities and, furthermore, the 93 percent minimum standard is apparently based on that report's statement that the plant at low end of the range of intake capacity reduction will reduce the intake flow by "approximately 93 percent." In contrast, USEPA had concluded that closed-cycle cooling systems using saltwater can reduce water usage by anywhere from only 70 percent up to 96 percent.[19] The Board's reliance on 93 percent as the minimum performance standard is not adequately justified or supported.

4. Track 1 Must Recognize Alternative Technologies that Achieve Superior or Equivalent Impingement and Entrainment Reductions But That Do Not Reduce Intake Flow

The Draft Policy must be revised to expressly recognize the acceptability of innovative technologies that achieve superior or equivalent reductions in impingement and entrainment impacts without necessarily reducing intake flow. As currently drafted Track 1 requires a minimum 93 percent reduction in flow (and an intake velocity not exceeding 0.5 feet per second) and Track 2 can only be used if Track 1 is not feasible. Thus, the Draft Policy precludes a facility for which Track 1 is not determined to be infeasible from pursuing an innovative technological solution that reduces (or eliminates) impingement and entrainment impacts by more than 93 percent but does not necessarily reduce its intake flow rate by at least 93 percent (or meet the maximum intake velocity). The Board should not adopt a Policy that precludes innovative solutions.

For example, Dynegy is investigating the utilization of a technology known as a

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[18] EPRI, *supra* note 17, at p. 8-3.

[19] USEPA, Final Regulations to Establish Requirements for Cooling Water Intake Structures at Phase II Existing Facilities, 69 Fed. Reg. 41576, 41601 n.44 (July 9, 2004); USEPA Regulations Addressing Cooling Water Intake Structures for New Facilities (Phase I Rule), 66 Fed. Reg. 65256, 65273 (Dec. 18, 2001).

"Substratum Intake System". A Substratum Intake System would replace a plant's current cooling water intake system with a network of wells drilled horizontally beneath sand beds on the ocean floor. If proven feasible, this technology would provide near 100 percent reduction in impingement and entrainment, yet yield no reduction in cooling water intake flow. As a result, under the Draft Policy, the plant could find itself required to build closed-cycle wet cooling under Track 1, despite the presence of an alternative that would possess superior environmental benefits in all aspects (*i.e.*, impingement, entrainment, land use, air quality, aesthetics, etc.). The Draft Policy should not preclude that favorable outcome.

5. <u>Track 2 Needs Additional Flexibility and Clarification</u>

While the Draft Policy's approach to defining Track 2 in terms of "within 10 percent" of the reductions achievable under Track 1 (*i.e.*, an 83 percent reduction) is a vast improvement over the 2008 draft policy, Dynegy continues to have substantial concerns regarding the viability and implementation of Track 2. The key to a workable Track 2 standard is additional flexibility and certainty in implementation. Recognizing the Board's interest in material reductions in impingement and entrainment, Dynegy believes that significant reductions are likely attainable but that the required reduction must be determined based on further site-specific evaluation, and not on a specified "one-size-fits-all" minimum percentage reduction.

a. <u>The "Not Feasible" Standard May Render Track 2 Illusory</u>

The Draft Policy does not define "not feasible", the gatekeeper for entrance to Track 2. In addition, the "not feasible" determination is to be made in each Regional Board's discretion. Thus, Track 2 may be no option at all: it can only be pursued if Track 1 is "not feasible", an undefined, vague term that is ripe for conflicting Regional Board determinations, resource intensive evaluation by Regional Boards and, ultimately, paralyzing legal challenges.

The failure to define or provide clear guidance on the prerequisite for Track 2 applicability is highly problematic. At Morro Bay, for example, the CEC soundly rejected closed-cycle cooling as infeasible, yet it is entirely unclear if Morro Bay would qualify for Track 2. In fact, the CEC expressly found that closed-cycle cooling would cause greater overall environmental harm than continuing the use of OTC[20] and went so far as to state that even if dry cooling were free, it would not recommend dry cooling at Morro Bay. Morro Bay 3rd RPMPD at 10 and 377 (emphasis added) ("[b]ased on the evidence in our record, we firmly believe that *even if dry cooling were feasible and cost free*, it would not offer the environmental benefits to the Morro Bay Estuary that a successful [Habitat Enhancement Plan] will provide."). Morro Bay is also subject to existing noise ordinances and zoning restrictions that prohibit the use of alternative cooling technology, and the City of Morro Bay adopted resolutions that opposed cooling towers due to their adverse impacts including visual blight and noise. In addition, given that the plant is located far from the load pocket in its relatively undesirable location in ISO zone ZP26, and its low level of dispatch as a result of its comparative inefficiency, Morro Bay has been challenged to find a source of revenue sufficient to cover its operating costs. When the

[20] Morro Bay 3rd RPMPD at 353, Finding 27.

plant's contract expires, it is far from certain that the market would support recovery of the significant incremental investment required to retrofit the plant with closed-cycle cooling. In addition, the operation of Morro Bay is contingent upon a lease of the cooling water outfall property held by the City of Morro Bay. This lease expires at the end of November 2012, and prospects for its renewal are uncertain.

Despite all of this, it is unclear whether Morro Bay would even qualify for Track 2. At the very least, the Board needs to provide clear guidance on what "not feasible" means. However, any attempt by the Board to explain or define "not feasible" -- either in the Policy or in guidance -- must not be exclusive and limiting, as was attempted in the poorly conceived definition of the term "feasible" set out in the Board's draft 2008 OTC policy. Rather, the Board should explain that "not feasible" recognizes all appropriate factors affecting feasibility at a specific power plant. That should, consistent with *Entergy Corp. v. Riverkeeper, Inc.*, include costs. Moreover, in explaining "not feasible, the Board should explicitly deem as presumptively valid any prior CEC site-specific determination that closed-cycle cooling is not feasible. Any such CEC determination was made on a site-specific basis after a detailed and comprehensive review process that was open to public participation and which gave great weight to the views of the respective Regional Water Quality Boards. The Board should not now second-guess those determinations or require an owner/operator to demonstrate infeasibility a second time. To do so would unnecessarily impose substantial costs and needlessly delay the implementation process.

b. <u>Track 2 May Not be Technically Achievable</u>

Assuming a Regional Board determines that Track I is "not feasible", it is questionable whether many OTC facilities can realistically achieve Track 2's minimum 83 percent reduction in impingement mortality and entrainment.[21] The performance of any individual cooling water intake technology (*e.g.*, aquatic filter barrier, fish returns, wedgewire screens, behavioral devices) can vary greatly depending on site-specific factors.[22] During the CEC siting process for both Moss Landing Units 1 & 2 and the replacement plant at Morro Bay, all known mitigation technologies were examined and rejected. At Moss Landing, the CEC rejected screens, nets, aquatic microfiltration barriers, and fish pumps because they were not expected to substantially reduce impingement or entrainment. CEC Decision, *supra* note 6, at 158. Further, the NPDES permit proceeding rejected wedgewire screens, fine-mesh screens, and aquatic microfiltration barriers as not being demonstrated technologies for reducing entrainment at the Moss Landing power plant and/or not demonstrated for the environment at Moss Landing. *Staff Report, supra* note 7, at 5-8. Similarly, at Morro Bay, the CEC rejected each of the alternative technologies as impractical, experimental, only having minor benefit regarding impingement, and/or not benefiting entrainment. CEC, *Staff Report, Morro Bay Power Plant Project, Final*

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[21] *See* EPRI, *supra* note 4, at App. A (discussing the performance abilities of alternative fish protection technologies).

[22] As repeatedly explained in the Tetra Tech study, "the effectiveness of other technologies commonly used to address [impingement and entrainment] impacts could not be conclusively determined for use at [the specific facility]. As with many existing facilities, the site's location and configuration complicate the use of some technologies that might be used successfully elsewhere." Tetra Tech, *supra* note 13, at I-19 and J-35.

Staff Assessment - Part 3, at 2-33 to 2-37 (Apr. 2002).

As a result, for the many power plants where Track 1 is infeasible, there is no known exclusion technology that would allow a facility to comply with the Track 2 requirement. The only possible compliance strategy for a plant in such a position would be to seek compliance through the adoption of operational restrictions, coupled with the application of technologies which, while insufficient in and of themselves to achieve compliance, would contribute to a reduction in the flow of cooling water through the plant. Through a combination of unit retirements, variable speed pump installation, modification of daily dispatch rates, screenhouse modifications, and prohibitions on dispatch during defined periods of time during the year, some facilities may be able to approach the Track 2 standard. For example, for a plants such as Morro Bay or Moss Landing Units 6 & 7 (should Track 1 be infeasible or if the wholly disproportionate standard not apply facility wide), 83 percent may be beyond what is technically achievable. Moreover, even if some combination of controls is thought to be able to achieve 83 percent reduction, actual monitoring after installation of Track 2 controls may show otherwise.

c. Track 2 Needs a Definitive End

A third major concern is that Track 2 does not have a definitive end. Some OTC plants may be able to approach an 83 percent reduction using approved controls but nevertheless come up short. In that event, the Draft Policy apparently would force the plant to shutdown or, alternatively, face substantial penalties and potentially significant costs as it implements another technology. That result -- forced shutdown or a potentially repeating cycle of costly technology installation -- must be avoided. The efficacy of alternative cooling water technologies is highly variable and subject to a multitude of factors over which the discharger has no control. If the approved technology is appropriately installed, operated and maintained but does not, through no fault of the owner/operator, reach the compliance standard, the owner/operator should not be punished by then having to install new controls. Once approved Track 2 controls are implemented, the source should optimize those controls, but Track 2 must not force plant shutdown or be continually subject to second guessing and reopening with each iteration requiring different, costly controls.

d. Dynegy Supports Track 2's Facility-Wide Applicability

Dynegy supports the Board's decision to apply Track 2 to an existing power plant "as a whole", rather than on a unit-by-unit or intake-by-intake basis. For example, at Moss Landing, habitat restoration projects have already been implemented to offset the OTC environmental impacts of Units 1 & 2. Nevertheless, if it is feasible and makes economic sense to retrofit Moss Landing Units 1 & 2 with dry cooling (rather than pursue infeasible reductions from Units 6 & 7), the reduction realized from doing so should be credited to Unit 6 & 7's compliance with Track 2. Similarly, at Morro Bay, the permanent retirement of Units 1 & 2 (if ultimately pursued) should be credited toward the plant's compliance with Track 2. The facility-wide approach properly recognizes that a power plant may have multiple units that often are very different in physical and operation characteristics and have complex interrelationships that may significantly impact BTA decisions and feasibility determinations.

e. Without Improvements, the Track 2 Performance Standard is Arbitrary

To the extent, the Board does not make Track 2 workable by providing additional flexibility and certainty in implementation, the Track 2 performance standard -- "within 10 percent" of Track 1 -- is arbitrary and capricious. The Board has not offered any support for the "within 10 percent" of Track 1 standard as either necessary for achieving environmental benefits or achievable at all OTC facilities using a combination of technology and operational controls that do not install closed-cycle cooling. Put another way, why is the standard within 10 percent and not, for example, within 15 percent? Moreover, the arbitrariness of the Track 2 performance standard is further apparent in that it is pegged to a Track 1 minimum performance standard that is itself arbitrary.

B. Electrical Grid Stability Must Be an Integral Part of OTC Policy Implementation

The reliability of California's electric grid depends on the ability of the electrical generators to meet the State's increasing demand for electricity. By limiting the use or potentially causing the shutdown of any number of the 21 California OTC plants, the Draft Policy potentially would cause significant and serious negative impacts on the stability of the State's electrical grid, particularly with respect to peak demand periods and in localized service regions. Given the importance of maintaining electrical grid stability, it is imperative that the Board and its staff work in close collaboration with the CEC, California Public Utilities Commission (CPUC), and California Independent Systems Operator (CaISO) -- the Energy Agencies -- not only in determining what impacts a state-wide OTC policy will have on grid stability, but also in the implementation process to ensure that grid reliability is, in fact, maintained.

While Dynegy appreciates and recognizes the Board and staff's efforts over the past year to address electric reliability concerns in developing the Draft Policy, we remain concerned that the Draft Policy would limit the input of the Energy Agencies in implementation of its requirements. As written, the Draft Policy limits the role of Energy Agencies to participating in the SACCWIS, which will only advise on proposed implementation schedules. Given the importance and complexity of grid stability, the Board and its staff need to coordinate closely throughout the implementation process with the Energy Agencies.[23] The Energy Agencies are not just interested stakeholders and, the OTC policy needs to be a

[23] ICF Jones & Stokes, *et al.*, *Electric Grid Reliability Impacts From Regulation of Once-Through Cooling in California*, 63 (Apr. 2008) ("Perhaps the most relevant conclusion of this study, therefore, is that continued cooperation between the state's water agencies, energy agencies, utilities, power plant owners and non-governmental organizations is vital to maintaining electric system reliability standards while achieving water quality goals. Opportunities to continue this cooperation include the CAISO's current study of the effect of aging and OTC plant retirement, as well as its comprehensive transmission planning process, and the CEC's ongoing investigation of OTC issues.").

coordinated effort amongst all these agencies to prevent unacceptable reliability impacts.

To that end, Dynegy recommends that the Board revise the Draft Policy in several ways. First, the Board should expressly define the SACCWIS's role to include advising on the discharger's proposed implementation plan. Paragraph I of the Draft Policy's Introduction states that the SACCWIS "will assist the Water Boards in reviewing implementation plans and schedules submitted by dischargers pursuant to this Policy." Contrary to that statement, the second sentence of section 3.B(1) of the Draft Policy would limit the role of the SACCWIS to reviewing "the owner or operator's proposed implementation schedule" and section 3.B.(2) would limit the SACCWIS's recommendations to the implementation schedule. Given the importance and complexity of grid reliability issues and consistent with Paragraph H of the Introduction, the Draft Policy should be revised to expressly state that the SACCWIS will advise on both the proposed implementation plan and schedule.

Second, the SACCWIS must comply with California's open meeting laws. The SACCWIS is an advisory committee to a state agency and, as such, falls within the definition of "state body" as defined in the Bagley-Keene Open Meeting Act. *See* Gov. Code § 11121. The Bagley-Keene Open Meeting Act requires that all meetings of the SACCWIS, and meetings of the State or Regional Water Boards when considering recommendations from the SACCWIS, be open and public, that notice be provided, and that the public be allowed to directly address the state body on each agenda item. *See* Gov. Code §§ 11123, 11125, 11125.1, 11125.7.

Third, the SACCWIS must be involved more often than only once initially (one year after the effective date of the Policy) and, thereafter, every two years starting in 2013. The importance of electrical grid stability and the complexity of changing conditions affecting grid stability dictates constant monitoring. The SACCWIS and Board should be engaged on grid stability as related to the OTC plants on an ongoing basis. Furthermore, Dynegy recommends that SACCWIS meet at least once every six months.

C. The Implementation Schedule Must Provide Flexibility to Reflect Implementation Realities

The Draft Policy fails to provide flexibility in the implementation process to accommodate unforeseen circumstances, changes in market conditions and load growth, or problems with permitting and equipment contracting.[24]

As currently drafted, the Policy would require any change to the implementation schedule to first go before the Board through a noticed rulemaking proceeding, and then the Regional Board would have to take up a permit amendment through a separate proceeding. Instead of requiring such a lengthy, cumbersome process with numerous points for indefinite

[24] To the extent scheduling implementation of BTA requirements requires prioritization, the Board should, subject to grid reliability concerns, establish a presumption that plants using more cooling water per MWh generated (*i.e.*, plants with a higher MG:MWh ratio) should be required to comply before those plants that use less cooling water per MWh generated. Such a presumption would focus compliance on those plants with, all things being equal, the potentially largest impact.

delay, the Draft Policy should clearly provide that the Regional Board can directly amend the timeline for each plant as determined by the SACCWIS via an administrative permit amendment. An example of the need for such flexibility is that the Draft Policy would require the owner/operator to predict the future of its OTC facility and propose a "realistic" implementation schedule that is as short as possible. That is not an easy task. If the proposed implementation plan requires that the facility obtain permits for retrofits, the implementation schedule submitted to the Board will necessarily be based on an estimate of how long it will take to obtain a permit (or multiple permits) from the appropriate regulatory agency (or multiple agencies). Regulatory delays may well interfere. In accordance with basic notions of fairness, an owner/operator should not be held responsible for failure to meet implementation deadlines for reasons beyond its control. The Board must consider this and provide flexibility in the timeline for such obstacles.

A second concern is the apparent lack of flexibility in the process if market conditions change during the implementation period warranting a change in the implementation plan. An owner/operator of an OTC facility should not be locked in to its initial implementation plan. Rather, the opportunity to modify an implementation plan must exist. For example, a plant may elect to shut down rather than repower based on current regulatory and market conditions, but, if, for example, three years from now the economy improves or if the long term procurement process provides an opportunity for a power purchase contract, repowering or retrofitting may become a viable option. The Draft Policy should expressly recognize that implementation plans may be amended.

Third, the Draft Policy requires an owner or operator to submit a proposed implementation plan within six months of the effective date of the Policy. That's simply not enough time to conduct the thorough engineering and operational studies and financial analyses needed to evaluate the feasibility of various complex compliance options. Dynegy requests that the Draft Policy be revised so that all facilities with compliance deadlines on or after December 31, 2012 not be required to submit the initial proposed implementation plan until one year after the effective date of the Policy. Extending the initial submittal deadline will not delay the ultimate compliance deadlines; to the contrary, it may eliminate delays by eliminating the need for changes to the implementation plan.

Finally, the Draft Policy should explicitly prohibit Regional Boards from accelerating implementation schedules as recommended by the SACCWIS. OTC facility owner/operators, as well as grid reliability, need scheduling certainty. Regional Boards should not have the authority to accelerate implementation schedules that have been carefully balanced by the Energy Agencies to ensure grid reliability.

D. The Draft Policy Must Give Credit for Existing Mitigation Projects

The Draft Policy must give full credit for purposes of meeting the required interim mitigation measures, as well as the wholly disproportionate mitigation requirements, to those power plants that have existing habitat restoration projects to address their OTC impacts.

For example, at Moss Landing, the CEC approval and NPDES permit imposed mitigation and restoration programs that were designed to address the OTC impacts of the Units 1 & 2 throughout their operating life.[25] Specifically, the owner of the Moss Landing power plant was directed to pay $7 million to a dedicated fund to be used by the Elkhorn Slough Foundation for the acquisition and permanent preservation of lands that directly impinge on or contribute damaging impacts to Elkhorn Slough, habitat restoration activities, and long-term stewardship of the mitigation projects in perpetuity.[26] Those programs have been successfully implemented: as of July 18, 2009, the Elkhorn Slough Foundation had acquired 2,143 acres and leveraged the initial $7 million to acquire real estate valued at $30 million, as well as engaged in phased restoration activities at six properties in the Elkhorn Highlands and a series of wetland properties.[27]

Because the OTC impacts of Moss Landing Units 1 & 2 have already been offset for the Units' entire operating life, Moss Landing Units 1 & 2 should be deemed to meet any mitigation requirements imposed in the Draft Policy. Moss Landing should not now be subject to additional mitigation requirements where the alleged impacts have already been addressed. To now require Moss Landing Units 1 & 2 to implement additional mitigation measures (either to meet the interim mitigation requirements or the wholly disproportionate mitigation requirements) to address alleged harms that have already been addressed would be unfair, harshly punitive, and entirely unjustified. Simply put, Moss Landing Units 1 & 2 should not be required to pay a second time because its OTC impacts have already been offset through a thoroughly vetted, State-approved, and implemented habitat restoration project.

While the Draft Policy provides that existing mitigation efforts may meet the interim mitigation requirements, Draft Policy §2.C(3)(a) leaves to the Regional Board's satisfaction the determination of whether an existing mitigation effort required by state or federal permits/approvals will be given credit. That is unacceptable. Where existing mitigation is already required by permit, such as Moss Landing, the Draft Policy must clearly state that the interim mitigation requirement is deemed satisfied or does not apply. The Regional Boards should not now have the authority to require additional mitigation requirements where they previously determined the mitigation that was needed to offset impacts. In addition, Draft Policy §4.C, the mitigation requirement in the wholly disproportionate provision, must be revised to include language expressly recognizing that existing mitigation measures are to be given full credit.

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25 The DSED, p. 74, incorrectly states that Moss Landing's "NPDES permit found that the §316(b) BTA standard was met, in part, by funding" a mitigation project. The NPDES permit 316(b) BTA determination for Moss Landing was not based, in part, on the mitigation project; rather the Regional Board imposed the mitigation requirement separate and apart from the BTA requirements. The Board should correct that erroneous statement in the DSED.

26 Commission Decision, *supra* note 6, at 170-172, 194-200; NPDES Permit No. CA0006254, Findings 50 and 51. At Morro Bay, the CEC approval requires implementation of a habitat enhancement project, with the Regional Water Board to determine if the applicant's proposed funding of $12.5 million is sufficient. Morro Bay 3rd RPMPD at 381, Finding 23.

27 Elkhorn Slough Foundation, *The Elkhorn Slough Environmental Enhancement and Mitigation Plan, Interim Report, Annual Update,* July 2009, at 3, 4, 7.

Finally, Dynegy supports the Draft Policy's express recognition that interim mitigation may be satisfied solely by funding a mitigation project (rather than requiring a power plant owner/operator to implement a mitigation project itself) and, by not imposing strict requirements on the design and implementation of a mitigation project, its recognition that owners/operators have broad flexibility in designing and implementing a mitigation project. For example, Moss Landing satisfied its environmental enhancement program requirement by a one-time payment of $7 million to a dedicated account for use by the Elkhorn Slough Foundation. Flexibility is needed in designing and implementing a mitigation project, be it for interim mitigation or wholly disproportionate mitigation. Dynegy opposes any attempt to limit that flexibility regarding interim mitigation (either in the language of the Draft Policy or through other Board guidance), such as limiting to whom mitigation payments can be made, requiring upfront payments as opposed to annual payments, etc.

E. Design Flow is the Proper Basis to Calculate Baseline

Dynegy strongly supports the Draft Policy's use of design flow baseline in determining compliance with the Track 1 and 2 standards. Use of a design flow baseline has numerous advantages over performance-based baselines (*e.g.*, historic actual flow), is consistent with OTC requirements in other states[28] and, for those power plants where Track I is infeasible, will be essential to enabling a power plant to have any realistic chance of meeting the proposed Track 2 standard. A design flow baseline may also allow certain low use plants to operate only when needed and would preserve the ability of power plants to operate at their maximum flow when needed to meet California's electricity demands.

The Draft Policy's use of design flow is supported by New York State's determination that design flow is the appropriate baseline to implement its own state BTA rule and policies, as well as for federal 316(b) purposes. After a contested adjudicatory hearing in the NPDES permit for Dynegy's Danskammer Station, the Department of Environmental Conservation (DEC) Deputy Commissioner concurred with the ALJ's finding that the full-flow design baseline "should be used to determine the facility's compliance with entrainment and impingement performance standards" and that the DEC's rationale for selection of the design baseline was "convincing and well-supported".[29] Specifically, use of a design baseline ensures fairness among energy producers; recognizes that every electric generating facility has the potential to operate at full-flow conditions given the deregulated nature of the electric generating industry; is consistent with federal requirements; is consistent with the intent to reduce adverse effects from cooling water intake structures because any reductions in flow, regardless of subjective motivation, reduce entrainment and impingement; does not unfairly punish facilities that have recently operated at lower flow levels by not allowing them credit for

[28] *Riverkeeper, Inc. v. Johnson*, 861 N.Y.S.2d 155 (2008), *appeal denied by Riverkeeper, Inc. v. Johnson*, 2009 N.Y. LEXIS 555 (N.Y. Jan. 22, 2009) (upholding Danskammer Generating Station, New York State DEC No. 3-3346-0011/00002, SPDES No. NY-0006262 Decision of the Deputy Commissioner (May 24, 2006)).

[29] Danskammer Generating Station, New York State DEC No. 3-3346-0011/00002, SPDES No. NY-0006262 Hearing Report, Daniel P. O'Connell, ALJ, 64-69 (Hearing Report) (attached to the May 24, 2006 Decision of the Deputy Commissioner, *supra* note 28).

flow reductions that have already been implemented; and is an appropriate regulatory approach because of the inherent variability in operating capacity that electric generators face from year to year.[30]

III. COMMENTS ON SPECIFIC SECTIONS OF THE DRAFT POLICY

Section 1 - Introduction

Paragraph G states that the intent of the Policy is to ensure that beneficial uses of the State's waters are protected. Industrial use (*e.g.*, cooling water) is one such legally recognized beneficial use, yet the Draft Policy fails to explain how such use is protected by the Policy. The Board must expressly recognize that industrial use is a beneficial use.

Section 2 – Requirements for Existing Power Plants

A. Track 2, Draft Policy § 2.A(2)

To make Track 2 implementation viable, the Board should revise the Draft Policy as follows:

1. The Draft Policy should specify that where Track 2 compliance is based solely on flow reductions, compliance will be measured on an annual basis (without the need for impingement and entrainment sampling – see comment below). Any shorter-term flow reduction measure (*e.g.*, monthly basis) is unworkable and would potentially cause grid reliability issues by limiting electricity production during periods when the need for electricity is the greatest.

2. Given the difficulties in and high cost of directly measuring cooling water volume flows, the Draft Policy should allow the use of appropriate calculations to demonstrate flow reduction where flow reduction is selected as a compliance strategy, rather than requiring direct measurement of cooling water volume.

3. The Draft Policy should give credit for both entrainment and impingement survival. As currently drafted, Track 2 would require a comparable level (*i.e.*, within 10% of the reduction achievable under Track 1) of reduction for both "impingement mortality and entrainment". Thus, credit apparently would be given for impinged fish that survive, but not allowed for entrained organisms that survive. The standard should be clearly expressed in terms of both "impingement mortality and entrainment mortality". As succinctly explained by the *Staff Report* in the Moss Landing NPDES permit proceeding, "[s]imply reducing rates in entrainment is not the objective. The objective is to reduce mortality." *Staff Report*, *supra* note 7, at 9 (emphasis in original). Site-

[30] The ALJ's Hearing Report, which was subsequently approved by the DEC Deputy Commissioner, discusses the baseline issue in detail before concluding that "calculating the baseline by using the full-flow capacity is a rational, conservative approach." Hearing Report, *supra* note 29, at 68-69.

specific scientific studies demonstrate that organisms survive entrainment, with some species showing significant entrainment survival rates.[31] It is unfair to penalize those power plants that have designed their OTC systems to enhance survival of entrained organisms (*e.g.*, reduced organism transit time through the cooling system, elimination of biocide) by not allowing credit for entrainment survival.[32] Allowing credit for entrainment and impingement survival where demonstrated by site-specific studies potentially will be a very important factor in giving certain California OTC plants a realistic chance of meeting the Track 2 standard.

B. Interim Mitigation Requirements, Draft Policy § 2.C(3)

In addition to the comments set out above in II.D, the Draft Policy's requirements for interim habitat restoration should be revised as follows:

1. The Draft Policy should clarify that funding of interim mitigation requirements may be based on projected or actual annual flows during the interim period. Because interim mitigation is short-term temporary measure, detailed, complex biological models should not be required. In addition, up-front, one-time payments should not be required, given that the retirement date of certain power plants may not be certain.

2. The Draft Policy should clarify that once the approved mitigation project has been fully funded, the owner/operator's obligation is deemed fulfilled. Follow-up studies should not be required and, because it is only an interim measure, the owner/operator should not be held responsible if the efficacy of the mitigation project ultimately falls short of what was anticipated.

<u>Section 5 – Track 2 Monitoring Provisions</u>

The Draft Policy should be revised to state that Track 2 monitoring is not required when compliance is based solely on flow reductions. A power plant that chooses to comply with Track 2 based solely on flow restrictions should not be required to perform initial baseline

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[31] *See* Morro Bay 3rd RPMRD at 310 (testimony showing entrainment survival rates for larval fish and vertebrates exceeding a mean average of 50 percent and total survival rates of 88-98 percent for naked goby); Testimony of Duke Energy Moss Landing LLC, *supra* note 14, at 6, 9 n.13 (up to 80 percent of certain species survive entrainment at Moss Landing). In addition, at Dynegy's Danskammer Station, New York DEC allowed entrainment survival credit based on a site-specific scientific analysis. *See* Hearing Report, *supra* note 29, at 69-76 (concluding that DEC's allowance of an entrainment survival credit was justified because it was based on detailed site-specific studies conducted at the plant). *See also* EPRI, *Review of Entrainment Survival Studies: 1970-2000*, Technical Report No. 100757 (2000).

[32] Site-specific credit for entrainment survival is consistent with *Riverkeeper II, see* 475 F.3d at 126-127 (not rejecting entrainment survival credit outright), and, in fact, USEPA's rule (and prior 316(b) guidance) had allowed recognition of entrainment survival for "well-constructed, sites-specific" studies. 69 Fed. Reg. at 41620. Allowing credit for entrainment survival also is consistent with the fact that the Draft Policy's standard is much more stringent than USEPA's now rescinded Phase II Section 316(b) standard. *See id.* ("If EPA had incorporated entrainment survival into any of its conclusions regarding the appropriate [national] performance standards, then the actual performance standard would most likely have been higher.").

impingement or entrainment studies or, after Track 2 is implemented, to perform periodic impingement or entrainment sampling to confirm impingement and entrainment controls. Instead, the power plant should only be required to demonstrate the reduction in cooling water volumes. The Board has decided that flow reductions under Track 1 do not require costly baseline impingement or entrainment studies since reductions in flow will proportionately reduce adverse environmental impact. The same logic applies equally to Track 2 when a plant complies using only flow reductions. Requiring impingement or entrainment studies in that case would be meaningless and only serve to impose significant additional costs.

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Overall, the Draft Policy is an improvement over the 2008 draft policy, but several important concerns remain that must be resolved if the Board is to adopt a workable OTC policy. In addition, certain provisions of the Draft Policy need to be fine tuned.

Dynegy appreciates the Board's consideration of our comments on both the Draft Policy and the DSED. We look forward to continue working with the Board to develop a workable OTC policy that reasonably balances the many complicated and important considerations involved. If you have any questions concerning Dynegy's comments, please contact Barb Irwin, Director Environmental Western Fleet Operations, at 925-803-5121.

Sincerely,

Daniel P. Thompson KAM

Daniel P. Thompson
Vice President
Dynegy Western Fleet Operations

cc: Office of the Governor
California Energy Commission
California Public Utilities Commission
California Independent Systems Operator