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DYNEGY

May 26, 2009

<u>**Via E-Mail with Hard Copy by U.S. Mail**</u>
California Energy Commission
Dockets Office, MS-4
Re: Docket No. # 09-IEP-1O
1516 Ninth Street
Sacramento, CA 95814-5512
docket@energy.state.ca.us

**Re: 2009 IEPR – OTC; Docket No. 09-IEP-1O
Comments on CEC Workshop regarding Implications on Electric Reliability of Proposals for Mitigation of Once-Through Cooling of Existing Electric Generating Facilities**

Dear Sir or Madam:

Dynegy Inc. (Dynegy) submits these comments in follow-up to the California Energy Commission (CEC) 2009 Integrated Energy Policy Report Committee's May 11, 2009 workshop regarding implications on electric reliability of proposals for mitigation of once-through cooling (OTC) of existing electric generating facilities.

Dynegy would like to point out that the stated goal of the State Water Resources Control Board (SWRCB) in their 2008 scoping document is to implement the Clean Water Act section 316(b), not to eliminate the use of once-through cooling. If the State's goal is to reduce the effects of once-through cooling on marine and estuarine life, all discussions on how to implement the Clean Water Act should include the full range of options available to power plant owners. The proposed policies and workshops should not pre determine which technologies work best at each site. As illustrated in our comments below, each power plant has different considerations that determine what type of technology can be used at each site. An indiscriminate requirement to phase out the use of once-through cooling would preclude Dynegy and other generation owners from pursuing innovative solutions to this problem.

The comments below specifically address the six "Questions For Generator Panel" raised in notice for the CEC workshop.

1. **What measures are currently employed at your company's OTC units to reduce environmental impacts? What other measures are under study and will the results of such studies be released to the public?**

   <u>**Measures Currently Employed**</u>

   i. **Moss Landing**

Moss Landing consists of two sets of units differentiated by technology and vintage. Units 1 & 2 are natural gas-fired 2 X 1 combined cycle units built in 2002. Units 6 & 7 are natural gas-fired boiler units built in the early 1960's.

Units 1 & 2 minimize impingement and entrainment via the design of their cooling water intake structure, which includes vertical bar racks followed by traveling screens (effective mesh size of 5/16 inch) that are installed at an angle in order to reduce water velocity across the screens. Additionally, the CEC approval authorizing construction of Units 1 & 2 required a $7 million payment for the funding of environmental habitat enhancement.[1] The CEC deemed this sum adequate to mitigate OTC impacts to the marine environment over the lifetime of these Units.

Units 6 & 7 have vertical bar racks and traveling screens (3/8 inch mesh) of an older design.

At all Moss Landing units, the temperature differential between cooling water entering and leaving the plant's cooling systems is capped by the local water district. Both instantaneous and daily average limits apply. In addition, for all units, the plant ceases to circulate cooling water within two hours of unit shutdown.

ii. Morro Bay

All units at Morro Bay minimize impingement and entrainment by utilizing bar racks followed by traveling screens (3/8 inch mesh). In addition, at all units, the temperature differential between cooling water entering and leaving the plant's cooling systems is capped by the local water district. Both instantaneous and daily average limits apply. For all units, the plant also ceases to circulate cooling water within two hours of unit shutdown.

<u>Measures Under Study</u>

i. Moss Landing

As part of the CEC approval process in 2001 regarding Units 1 & 2, cooling system environmental impacts were studied in great detail. Additionally, a full body of detailed studies of alternative cooling systems, their cost, and their relative environmental impact were developed in subsequent legal challenges regarding the use of OTC. Included in these proceedings was detailed information on the feasibility and cost of closed cycle cooling. These studies are in the public domain and Dynegy does not object to regulatory agencies using that information in their evaluation of technology alternatives to OTC. In the coming months, Dynegy will be refreshing this analysis to develop up-to-date assessments of cost and permitting issues.

Specific retrofit studies have not been performed regarding Units 6 & 7. Dynegy has recently initiated an effort to examine the feasibility and cost of deploying alternative cooling technologies for these Units, though the time required to complete such studies has yet to be determined.

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[1] CEC Decision, Application for Certification Moss Landing Power Project, Docket No 99-AFC-4 (Nov. 2000).

Studies are also being performed to determine the extent to which cooling water volumes could be reduced via the replacement of existing water pumps with variable speed pumps. Whereas the existing pumps operate at the same fixed level regardless of plant load, variable speed pumps would allow the facility to better match cooling system flows with the level of production at the plant. This may allow for material reductions in cooling water flow, especially during off-peak hours of the day.

Less conventional alternative means of compliance are also being investigated, such as the relocation of the cooling water intake structures to a greater depth in the ocean. Dynegy is exploring the feasibility of moving the cooling water intake structures to a depth at which the level of marine life is materially less than that at the current intake points, which are located in Moss Landing Harbor. At this time it is unclear whether such an approach would yield reduction in impingement and entrainment sufficient to meet developing standards, nor are the costs and permitability of such a project yet understood. The study of this approach is likely to take more than one year, given the necessity to capture marine organism data in all seasons.

ii. Morro Bay

OTC issues at Morro Bay were intensely studied as part of an effort to gain CEC approval of a replacement power plant project at Morro Bay. During the CEC process in 2004, it was determined that closed cycle cooling options at Morro Bay were infeasible due to a combination of air quality impacts and City of Morro Bay's concerns regarding visual blight and noise.[2] The City of Morro Bay's zoning ordinances prohibit the construction of the large cooling structures required for closed cycle cooling, and the City has passed a resolution specifically opposing the use of such technology at the plant. Relevant studies are available in the CEC docket.

As a result, alternative compliance options at Morro Bay are few. As at Moss Landing, the cooling water pumps are not variable speed pumps and, thus, run at full capacity regardless of the level of plant production. Dynegy will study the extent to which the cooling water volume can be reduced via replacement of the existing pumps with variable speed pumps.

2. Do you agree with the Energy Commission staff assessment that imposing wet or dry cooling towers (or each of their equivalents) on existing OTC fossil-fueled steam generators will most likely lead to retirement or repowering rather than refitting of the existing prime mover with cooling towers?

Yes. Putting aside the question of whether cooling tower (or equivalent) retrofits are even possible at a given site, it is highly improbable that the cost of such retrofits could be recovered from existing California power markets. The heat rates of these existing OTC units are such that the units have been relegated to fulfilling the grid's peaking needs. Capacity factors are low and no structured capacity market exists within

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[2] CEC, 3rd Revised Presiding Member's Proposed Decision, Morro Bay Power Plant Project Application for Certification (00-AFC-12), 328, 339-348 (June 2004).

California. In such circumstances, it is highly unlikely that Dynegy would make the sizable capital expenditure required to retrofit units, such as Moss Landing Units 6 & 7, without a contract with a credit worthy counterparty that was sufficient in term and price to allow for recovery of the capital expenditure. Given the age of the units and their relative efficiency, it is questionable whether Load Serving Entities would be willing to sign contracts that would allow for such cost recovery.

Replacing these old units with new, more efficient units on the same site would appear to be a viable, effective strategy for replacing such lost generation. The retirement of existing units would create the air emissions credits required to provide comparable replacement generation capacity and such replacement projects would realize the cost benefit associated with the existing fuel and transmission infrastructure. In many locations, such projects may also benefit from the support of their local communities, which would otherwise see their tax base and local employment degrade due to the closure of existing plants.

3. What are the conditions under which your company will choose to repower one or more of your existing facilities as opposed to retire the units? Do you currently expect these conditions to exist?

In order to repower a facility that would otherwise be retired, a generator must secure a contract for the replacement plant. This contract must be sufficient in term and price to allow for an appropriate return on the generator's investment.

Such conditions do not exist today, though it is conceivable that reforms to procurement practices could make such repowering 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. Towards that end, suggested reforms to the typical RFO process include:

i. <u>Offering repowered plants a contract term that is similar in duration to the economic life of utility self-build options</u>. 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. When independent power producers (IPP's) respond to utility RFO's, however, they are typically required to agree to contract terms of 10 years. Additionally, it is well understood within the industry that newly constructed power plants will be unable to find contracts for capacity beyond the initial term of their contract. No structured capacity market exists, and existing units are usually disqualified from participating in 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, IPP's 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.

ii. Transmission project evaluations must recognize the all-in cost of replacing a retiring plant, including the cost of generation at the other end of the line. Existing OTC plants not only provide local reliability benefits, but also supply 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) be able to 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.

iii. Consideration must be given to on-site repowering's associated benefits of reduced environmental impact, increased permitability, positive impacts to local communities, and equity to owners of threatened facilities. Alternative evaluations should 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 gas boiler plants jeopardized by OTC regulation changes are located in small, rural communities in which the plant comprises a major component of local tax revenues and employment. Loss of these plants without replacement facilities 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 IPP's 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 inflexible state OTC regulations that effectively require cooling tower retrofits in all instances. The continued presence of an IPP community in California will continue to 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. Do you view all of the units at each of your facilities as a group with a common fate, or can specific units have different fates?

Specific units can have different fates. For Dynegy, the best example of this is Moss Landing Units 1 & 2 vs. Units 6 & 7. The new units (Units 1 & 2) have lower heat rates and different operational characteristics than the old units (Units 6 & 7). The new units also use less cooling water and have available real estate next to them, whereas the old units use approximately twice the cooling water and have relatively little unoccupied real estate next to them. This suggests that the cost to retrofit Units 1 & 2, if ultimately required, would be less than for Units 6 & 7, and that the new units have a greater capacity to shoulder incremental capital investment than the old units. Questions regarding the likely remaining useful life of the old units (early 1960s vintage) would also come into consideration. For these reasons it is conceivable that Units 1 & 2 may survive, while Units 6 & 7 may not.

This is not to say that a cooling tower retrofit would ultimately be justified or required at Moss Landing Units 1 & 2. Detailed studies performed in 2003 for purposes of the NPDES permitting of Units 1 & 2 concluded that retrofitting these Units with dry cooling would diminish their combined capacity by 20 MW's and increase their heat rate from 6,790 Btu/KWh to 7,800 Btu/KWh. Given the large loss in capacity and unit efficiency, it is not clear that future market margins would justify the significant capital outlay.

5. What conditions (lead time, utility definition of specific products, etc.) are necessary for your company to effectively participate in utility RFOs for replacement capacity or energy?

The most important condition would be a definition of what operating characteristics the ISO would like to see provided by a replacement facility. There are numerous possible configurations of generating equipment that could be bid, depending on considerations regarding desired start-up time, total capacity desired, fuel efficiency, load following/ramping capability, black-start capability, etc.

Once the desired products have been adequately defined, a credible initial bid can be constructed in approximately four months. This should allow sufficient time to research equipment costs with vendors and determine an appropriate structure. After being shortlisted, a generator would likely require roughly three months to put together a final, binding bid.

For bids that are submitted, provisions should be made to allow for bid adjustment if the award and approval process are prolonged. Once a bid is awarded and approved, the generator would be locked into to its bid price, with some provision for indexing should the regulatory approval process become prolonged

Ideally, all bids would be evaluated by the CPUC, ISO, CEC, and an independent evaluator, with the ultimate award made by the CPUC.

6. Given constraints on the location of new or replacement capacity to satisfy local reliability needs, limits of available credit, etc. can one expect robust competition in narrowly targeted RFOs? If market power is a concern, what methods might be used to reduce it?

Given the nature of the services to be replicated via new facilities, the pool of bidders will vary. For plants such as Moss Landing and Morro Bay, the likely products to be procured would be overall supply adequacy and ramping capability to handle increasing levels of intermittent supply. In this case, the pool would likely be larger than that for local reliability services, and multiple transmission and/or generation bids may emerge.

If insufficient bids emerge or if local reliability is the service in question, market power concerns should be addressable via a sufficiently open negotiation of a long-term contract. The cost of generation is generally well understood both by those within the industry and by regulators. The ultimate goal of an IPP, such as Dynegy, is to deploy capital at a return that is commensurate with the level of risk associated with the contract. Generally, an IPP is highly likely to be willing to negotiate in an open manner with utilities, the CPUC, the ISO, etc., to develop a contract that reflects the cost of building, operating, and maintaining a facility, as well as provides a reasonable return on the capital invested.

Current capital market conditions would likely pose an impediment to a deep level of RFO participation. However, by the time such investments are likely to be required (2014, 2015?), capital markets will likely have regained some level of their former functionality. Projects backed by a long-term (i.e., not one limited to 10 years) contract with a credit worthy counter-party should stand a very good chance of receiving financing.

Dynegy appreciates the opportunity to comment on these important issues. If you have any questions concerning our comments, please call me at 926-803-5104.

Sincerely,

Randall Hickok

Randall Hickok
Managing Director –
Asset Management West

cc: Commissioner Karen Douglas, Chair, California Energy Commission
Commissioner Jeff Byron, California Energy Commission
Commissioner Jim Boyd, California Energy Commission
Commissioner Michael Peevey, Chair, California Public Utilities Commission
Commissioner John Bohn, California Public Utilities Commission
Mr. Yakout Mansour, President, California Independent System Operator
Chair and Members of the State Water Resources Control Board
Mr. Dan Pelliseer, Acting Deputy Cabinet Secretary, Office of the Governor