NRG West
1817 Aston Avenue, Suite 104
Carlsbad, CA 92008

NRG

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August 17, 2009

The Honorable Jeffrey D. Byron
California Energy Commission
Dockets Office, MS-4
1516 Ninth Street
Sacramento, CA 95814-5512

RE: Committee Workshop on Inter-Agency Analysis of Generation and Transmission Options for Eliminating Reliance upon Once-Through Cooling Power Plants – Docket No. 09-IEP-1O

Dear Commissioner Byron:

NRG Energy, Inc. (NRG) would like to express our sincere thanks for inviting us to participate in the above referenced workshop on July 28, 2009 and for allowing us the opportunity to testify before two of the panels. As you may be aware, NRG has been an active industry leader on this critical policy issue for over six years. While the economic downturn has had an impact on electricity demand, our region and California as a whole must continue to prepare for the replacement of the aging energy infrastructure in anticipation of the demand growth that is certain to return as the economy improves and facilities are forced to retire due to economic and environmental policy decisions. As a partner in the effort to achieve a transition from the old to the new, NRG is actively working to replace aging facilities at El Segundo Generating Station and Encina Power Station with environmentally superior technologies as well as support the state in meeting its carbon objectives through investment in wind and solar renewable resources.

While NRG is actively responding to the State's desire to replace once through cooled units and develop renewable resources, we remain concerned with the draft policy that the State Water Resources Control Board (SWRCB) has prepared for comment. As currently drafted, this proposal will require massive investment in generation and transmission infrastructure. In the South Coast alone (the Los Angeles Basin) the replacement of 7,400 MW of non-nuclear generation that is at risk in the near term will require approximately $9 billion in infrastructure alone. Not only is it an expensive endeavor to replace low cost capacity, but the State is already extremely challenged to permit and interconnect the large amount of renewable resources that are intended to come online to meet the 20% renewable mandate. The CAISO estimated that it will take between 9-10 years to interconnect the existing generation in the queue, the majority of which are renewable resources. Furthermore, the extremely difficult permitting environment is exemplified by the air permits litigation in the South Coast Air Quality Management District. The El Segundo repowering project that is implicated in the air permit lawsuits is the very type of replacement facility for once through cooled generation that is required to meet the SWRCB mandates. The State needs to consider the difficulty in replacing the facilities when it considers the timelines for phasing out once through cooled resources.

While replacing existing facilities is challenging, investing in existing ones is equally difficult. The way the state achieves its desire to replace once through cooled units cannot be separated from the electricity market structure. California has an electricity market that makes it difficult to invest in existing plants due to lack of a capacity market and limitations on energy market prices. Notable features of the existing market structure that support this statement include:

- Lack of a functioning capacity market – An organized market for capacity will assure that California achieves its desired resource mix most economically while maintaining essential reliability requirements. The market should produce a market price for capacity that investors can use to assess investment of new capital in existing plants and new reliability resources. Capacity markets have supported repowering of existing resources, new demand response, and new capacity investment in the Eastern organized markets.

- A mitigated energy market that does not fully reflect opportunity or scarcity costs. In addition, the California market lacks certain reliability products, such as a location reserve market, which could provide value to investors in these critical reliability services.

Due to lack of robust energy and capacity markets, new investment is only being made by utilities or via long term contracts with independent generators.

As California implements the greenhouse gas reduction law (AB 32), considers phasing out once through cooled units, and expands the renewable portfolio standard from 20 percent to 33 percent, the State should consider the overwhelming costs of these ambitious objectives. In addition, in considering the timelines for implementation the state must consider the timing risks involved with this level of infrastructure overhaul to develop a practical schedule for accomplishing new initiatives. These policies must carefully consider the implications on California's already fragile energy infrastructure investment environment in California.

NRG looks forward to continuing to work with you on this critical energy policy and applauds your efforts to guide this effort as it moves forward.

Sincerely,

Steve Hoffmann
President, NRG Western Region

cc: Michael Jaske, CEC

Workshop Agenda R.08-02-007

Inter-Agency Analysis of Generation and Transmission Options for Eliminating Reliance upon Once-Through Cooling Power Plants

Panel 1 and 3 Responses

NRG Energy Inc (NRG) is pleased to have participated in this Workshop and in particular on Panels 1 and 3. NRG intends to provide written comments on the State Water Resources Control Board (SWRCB) draft policy by September 30, 2009. NRG's comments below focus primarily on the questions in Workshop Panels 1 and 3; namely, the use of state procurement and power plant permitting policy as tools to meet SWRCB mandates.

Meeting the SWRCB policy will require massive investment in generation infrastructure. In the South Coast (Los Angeles Basin) alone the replacement of 7,400 MW of non-nuclear generation that is at risk in the near term will require approximately $9 billion. The way the state achieves this requirement cannot be separated from electric market structure. California already has an electric market structure that makes it difficult to invest in existing plants or construct new ones. Notable features of the existing market structure that support this statement include:

a. Lack of a functioning capacity market that has been used in comparable coordinated markets on the east coast
b. A mitigated energy market that does not fully reflect opportunity or scarcity costs. Thus new investment is only being made by utilities or via long term contracts with independent generators
c. Extremely difficult permitting environment. The litigation over air permits in the South Coast is especially notable.

The current coastal fleet has a large no. (21 GW) of steam boiler units. Excluding the two nuclear facilities, there are 49 gas-fired units at 17 facilities equating to 15,922 MW. These units, although having less desirable heat rates, have tremendous ramping and regulation capability and are fully permitted to be compliant with existing air quality regulations. This ramping capability must be replaced and this need must be carefully communicated to the market.

NRG RESPONSES TO PANELS 1& 3

Questions for Panel 1: Changes to procurement from a generator/developer/bidder point of view

1. Can OTC replacement be done via the IOU's RFO process?

   As a preliminary matter, NRG notes that a considerable amount of coastal generation is in LADWPs service territory so that needs to be addressed elsewhere.

   - The short answer is 'Yes," subject to the high cost which will stress ratepayer capacity to pay utility balance sheets. IOU procurement process can be used to ensure that new or repowered generation is procured to meet OTC mandates. The best solution is a capacity market. NRG along with other suppliers and load serving entities has supported a structure that would compensate existing generation in the transition and new generation.
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2. How should an RFO be structured, what changes are needed from the current process, to facilitate competition between possible greenfield sites, building new units on existing sites, and repowers that replace cooling systems?

   - RFOs for new generation have had locational requirements and these requirements will likely require more specificity to improve the likelihood of meeting OTC objectives.

   - Review the credit and collateral provisions. These existing provisions have proven to be onerous. The harder the utilities make it to enter into PPAs to support repowers, the harder it will be for the State to meet its OTC objectives.

3. How should RFO products be targeted to a particular location/product type?

   The more specific the RFO, the better bidders are able to tailor its offer to meet the needs of the IOU as well as the ratepayers. A significant improvement needs to be made in how much information is made available on the locations that are acceptable for OTC replacement. The draft joint agency staff proposal proposes a 10-LCR study. This study needs to be published in a manner timely so as to facilitate utility RFOs and bidder offers. It also needs to enumerate transmission upgrades that might expand the LCR boundary. Utility procurement departments may need to be more aggressive in pursuing incremental transmission upgrades in the transmission planning request window process to increase the acceptable locations for OTC replacement MWs.

4. Do the current markets provide adequate incentives to design plants to provide ancillary services (e.g. regulation, etc) to integrate renewables into the system?

   No. Current CAISO markets are inadequate to provide incentives to make incremental investment or design choices that would make ancillary services a priority over other considerations such as total capacity or full-load heat rate. RFOs have had vague descriptions of the desire for such flexibility and the state's current and emerging RPS policies create an obvious demand. However, bidders have very little concrete information to go by. More specificity in the RFOs is necessary. CAISO can also facilitate demand through the creation of forward reserve markets and the maintenance of robust AS markets that do not lean on out of market procurement.

5. What length of contract would be optimal?

   The existing policy that essentially requires contracts of 10 years or less if the IOU wants the ability to allocate net costs to all loads that benefit from the capacity. (Some IOUs do not seem to be concerned about the ability to allocate costs to non-IOU load and have issued RFOs for longer-dated contracts i.e., 15-, 20-, and 25 years). NRG supports the CFCMA capacity market proposal which would allow new capacity to obtain a 10-year strip of fixed capacity prices to support new investment. NRG has also entered into multiple 10-year PPAs with IOUs to support new generation and is not opposed to longer tenor deals.

   A functioning capacity market would send a signal that existing capacity has value, increase estimates of "residual value", and reduce the bid price of developers making 10-year offers. RFOs conducted without a capacity market framework will suffer because bidders will depend on the initial PPA to cover all project costs. In the end, the lack of reliance on competitive market structures is to the detriment of ratepayers.

6. How would a repowering via AB 1576 be conducted/approved/completed?

   The CPUC considered how to incorporate AB 1576 into its procurement processes in the last LTPP. AB 1576 created a new class of power plants: repowered units necessary for local reliability, whose costs would be recovered on a cost-of-service basis, even though they are not owned by a regulated electric utility. Only certain plants will qualify if they meet the following criteria:

   - Repowering of an existing project located within the existing boundaries of the existing plant and not requiring significant additional rights-of-way or fuelrelated transmission facilities, and would result in significant and substantial increases in efficiency;

- CEC mission certifies that the project is eligible for certification pursuant to Section 25550.5 of the Public Resources Code;
- CAISO (or local system operator) certifies that the project is necessary for local area reliability and the Commission or local governing body concurs; and
- The output is provided at cost of service.

At best, the CPUC's policy increased emphasis on giving generation alternatives that meet the criteria of AB 1576 and generation that reduced reliance on OTC a priority. IOUs are required to explain why AB 1576 eligible projects were not selected. Example quote from last LTPP Order: "To support the types of needs we anticipate in a GHG-constrained portfolio and to replace the aging units on which some of this authorization is based; we require PG&E to procure dispatchable ramping resources that can be used to adjust for the morning and evening ramps created by the intermittent types of renewable resources. Preference should be given to procurement that will encourage the retirement of aging plants, particularly inefficient facilities with once-through cooling, by providing, <u>at minimum</u>, qualitative preference to bids involving repowering of these units or bids for new facilities at locations in or near the load pockets in which these units are located. "

NRG supported the adoption of AB 1576 as a way to provide an alternative (cost-based) means of supporting repowerings that met specific beneficial objectives. That said, NRG favors bid-bases solicitations as they provide the most competitive outcomes and reduce perceived risks on both sides which will only increase costs and add time to the process of meeting OTC objectives. If the CPUC wants an explicit AB 1576 process, it should initiate the process as the intervenor proposals proposed and vetted in the last LTPP resulted only in the quasi "rebuttable presumption" standard already adopted.

Most important is the concern that all the benefits of repowering projects are properly considered and evaluated in a RFO – including quantifiable economic benefits and non-quantifiable social and environmental benefits.

7. What are the generator's plans for the existing OTC facilities?

NRG owns and operates the following coastal facilities:

El Segundo Power Station.
Long Beach Generation.
Encina Power Station.

The future of existing units depends heavily on market structure changes determined in the short run. Older units are critical for reliability yet depend on ad hoc procurement practices of IOUs. The only CPUC mandate is for the forward procurement of some local generation in a year-ahead time frame. This is very different form a forward capacity market. This market revenue uncertainty, combined with mitigated energy markets and arbitrary "final compliance" dates set by the SWRCB and its advisory committee, may lead to premature retirements that harm reliability and market efficiency.
NRG has or has plans to repower all of its sites. None of its repowering plans rely on OTC.

- **El Segundo**. A Petition to Amend the existing El Segundo Power Redevelopment Project is in process for a facility that provides high ramping capability and quick start. SCAQMD litigation and resulting permit moratorium has tie up issuance of final air permits. The Title V workshop and CEC workshop for the project were conducted and final CEC Staff Assessment was near completion.

- **Long Beach.** Repowered in 2007. Facility no longer requires OTC and the OTC has since been eliminated.

- **Encina**. We are awaiting the CEC's Final Staff Assessment (in September 2009) in response to the 2007 filing of an Application for Certification. The San Diego Air Pollution Control District issued their air permit (i.e., Final Determination of Compliance) pending CEC's decision in August 2009. The proposed Carlsbad Energy Center is a new facility that provides high ramping capability and quick start. The repower would be in conjunction with partial retirement of three OTC steam boilers. The site of the new generation is expandable and could support eventual retirement of all OTC on the site in the time frame articulated by draft SWRCB policy.

Questions for Panel 3: Power plant licensing

1. Is there any advantage to a repower project versus a greenfield project in the Energy Commission process as it exists today?

   By virtue of the process - no. On balance, the facts associated with repowering projects lead us to believe that repowers compete better than greenfield sites. Granted, there are the local control and or opposition to projects at the local level that all projects – greenfield and brownfield – must contend with. However, brownfield sites, for example, possess some advantages over greenfield sites in that much of the infrastructure and local permitting already exists. Moreover, there is the advantage to avail of existing infrastructure – thereby reducing some construction and permitting costs that would otherwise be borne by ratepayers.

2. Please discuss the concept of a plant designated by CPUC as an AB 1576 facility (i.e., AB 1576 says the CPUC can give a long-term cost plus contract to a brownfield repowering project; this hasn't been implemented).

   - Despite an extensive record submitted in the last LTPP proceeding, we are not aware of any CPUC process for having the CPUC designate a project as an "AB 1576 facility" We are open to staff proposals in this regard. Please see our responses above regarding repowering via AB 1576.

3. What are the pros and cons of a possible policy resulting in air districts reserving scarce air credits for plants identified as OTC replacement capacity and denying air credits to others?

   The current LA Basin local reliability area has a high degree of overlap with the SCAQMD basin. Affording air credits to OTC replacement facilities would allow for an aging fleet to be replaced where the replacement/repower is feasible and needed. Most of the aging fleet was built "in-basin" and today provides a critically valuable service to the grid as a whole. State-of-the-art generation with the flexibility of "quick-starts" and "ramping" afford the grid the ability to "shape" loads from renewable generation that is expected to come on-line. Characteristics of this new generation are critical given the intermittency of renewable power.

   The replacement of OTC technology where it is feasible will be a matter of time and economic conditions that some of these facilities will face as they continue to age and continue to be exposed to other market forces that may eventually impose operational burdens that will make them obsolete.

4. Please discuss the advantage/disadvantage to alternative sequencing:

   - Energy Commission permit, then a power purchase agreement; or
   - Power purchase agreement, then an Energy Commission permit.

   In today's economy, the chief concern is financing. The reality today is that without PPAs, repowering or any type of development is unlikely to occur. Absent an RFO, it is unlikely that companies would choose to engage an evaluating process that would arrive at a decision to engage the AFC process through the Commission. If however, there is an RFO and once the due diligence evaluation is complete – that's when companies would decide to move forward with an AFC process. But let me reiterate – without PPAs, projects are not likely to be built – greenfield or brownfield.

5. Should the Energy Commission siting process attempt to ensure that new power plants have the necessary operating characteristics to replace those of OTC capacity that is retired?

   No. The primary drivers of operating characteristics should be the CAISO capacity and ancillary services markets and the CPUC procurement processes. Going forward all new and repowered facilities will have to exhibit characteristics necessary to accommodate a carbon constrained world. The CEC process should take the project proposal form the applicant and ensure that it has met CEQA and other requirement to receive a permit.

6. What are the most environmentally and economically feasible technological alternatives, if any, to gas-fired generation for OTC replacement? Please discuss the generation options (both distributed and centralized) that you think will be available and practical within 10-15 years, assuming similar air quality constraints in regions such as the South Coast Air Basin.

   In the time frame contemplated by the SWRCB policy (10 years), the grid will always require the availability of natural gas fueled generation. No one has proposed a credible alternative. Even EAP II has residual demand met by fossil generation after the application of all other resources that come first on the loading order. Certainly the loading order should be exploited (energy efficiency, demand response, zero emission and renewable power). For the foreseeable future, however, the certainty, efficiency and clean attributes of natural gas fueled facilities will always be critical to grid reliability. The CPUC sponsored E3 study also confirms this.