Decision 12-04-046 April 19, 2012

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 10-05-006 (Filed May 6, 2010)

DECISION ON SYSTEM TRACK I AND RULES TRACK III OF THE LONG-TERM PROCUREMENT PLAN PROCEEDING AND APPROVING SETTLEMENT

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Summary

This decision addresses issues in System Track I and Rules Track III of the Long Term Procurement Plan Rulemaking. Many potential issues in System Track I are resolved, or at least deferred, by a proposed settlement supported by most of the parties. We approve the proposed settlement, and address one other System Track I issue not resolved by the settlement: a proposal by Calpine Corporation for utility solicitations aimed at existing power plants operating without contracts. A second System Track I issue, relating to local reliability requirements in the San Diego Gas & Electric service territory, was moved to Application 11-05-023.

In addition, this decision addresses a number of Rules Track III issues, specifically: procurement rules relating to power plants using once-through cooling, a proposal from Southern California Edison for a new generation auction, refinements to evaluating bids where utility-owned generation and independent generation are competing, utility procurement of greenhouse gas related products, a request from the Independent Energy Producers relating to generator recovery of greenhouse gas compliance costs, and general procurement oversight rules.

1. Background

The Order Instituting Rulemaking (OIR) initiating this proceeding divided the proceeding into three concurrent tracks. The OIR described those three tracks:

(1) Track I will identify California Public Utilities Commission (CPUC)-jurisdictional needs for new resources to meet system or local resource adequacy and to consider authorization of IOU [investor-owned utility] procurement to meet that need…

(2) Track II will address the development and approval of individual IOU "bundled" procurement plans consistent with § 454.5.

(3) Track III will consider rule and policy changes related to the procurement process which were not resolved in [Rulemaking] R.08-02-007, as outlined in greater detail below. (OIR at 9.)[1]

The December 3, 2010 Assigned Commissioner and Administrative Law Judge's (ALJ's) Scoping Memo and Ruling (Scoping Memo) reiterated this structure. A separate decision on Track II, relating to the utilities' bundled procurement plans, was approved by the Commission on January 12, 2012 in Decision (D.) 12-01-033.

A February 10, 2011 ALJ's Ruling[2] determined that the System Track I issues and a limited number of Rules Track III issues would be addressed on a concurrent procedural schedule. Because only a limited number of Rules Track III issues could be addressed on that schedule, the Ruling directed the parties to recommend which Rules Track III issues they wished to have addressed concurrently with the System Track I issues. (February 10, 2011 ALJ Ruling at 6-7.)

After considering party input at the February 28, 2011 pre-hearing conference and in pre-hearing conference statements, a March 10, 2011 ALJ

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[1] These tracks are referred to as System Track I, Bundled Track II, and Rules Track III.

[2] The full title of the Ruling is: *Administrative Law Judge's Ruling Modifying System Track I Schedule and Setting Prehearing Conference.*

Ruling[3] preliminarily identified four Rules Track III issues to be addressed concurrently with the System Track I schedule:

> 1) [P]rocurement rules relating to once-through cooling issues; 2) refinements to the bid evaluation process, particular weighing competing bids between utility-owned generation and power purchase agreements; 3) refinements to the existing timelines associated with the utilities' RFOs [requests for offers] for resource adequacy products; and 4) utility procurement of greenhouse gas related products. (March 10, 2011 ALJ Ruling at 4.)

In addition, based on input from the California Independent System Operator (CAISO), the March 10 Ruling reduced the number of complex modeling runs to be performed by the CAISO and the utilities, and provided the CAISO and utilities additional time to perform the remaining modeling runs.

Subsequently, the utilities and the CAISO filed a motion requesting additional time to complete their modeling and submit testimony. In a May 31, 2011 Ruling,[4] the ALJ granted this motion, and moved the date for utility and CAISO testimony to July 1, 2011. In a June 13, 2011 Ruling,[5] the ALJ added a fifth issue to Rules Track III, relating to procurement oversight rules. (June 13, 2011 Ruling at 6-7.)

Testimony was served by the utilities and the CAISO on July 1, 2011. Other parties served testimony on August 4, 2011. Evidentiary hearings were

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3 *Administrative Law Judge's Ruling Revising System Track I Schedule*, dated March 10, 2011.

4 *Administrative Law Judge's Ruling Granting Motion to Modify System Track I Schedule*, dated May 31, 2011.

5 *Administrative Law Judge's Ruling Addressing Motion for Reconsideration, Motion Regarding Track I Schedule, and Rules Track III Issues*, dated June 13, 2011.

held on August 11, 15-19, and 30, 2011.[6] Opening Briefs were filed on September 16, 2011, and Reply Briefs were filed on October 3, 2011.

2. System Track I

2.1. Proposed Settlement

A proposed settlement in System Track I was filed on August 3, 2011.[7] The majority of parties to this proceeding entered into the proposed settlement. The proposed settlement would resolve the fundamental issue in System Track I, which the proposed settlement defines as: "should the Commission determine that, due to system needs, the IOUs should be directed to obtain additional generation resources?" (Motion for Approval of Settlement Agreement at 4.) We approve the proposed settlement.

Two narrower issues in System Track I were not resolved by the proposed settlement. One unresolved issue related to the need for local generation capacity in the San Diego Gas & Electric (SDG&E) service territory. That issue will be addressed in Application (A.) 11-05-023, as described in the Joint

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[6] Consistent with the *Administrative Law Judge's Ruling Addressing Motion for Reconsideration, Motion Regarding Track I Schedule, and Rules Track III Issues*, dated June 13, 2011, additional reply testimony was presented on August 11, 2011.

[7] Motion For Expedited Suspension Of Track 1 Schedule, And For Approval Of Settlement Agreement Between And Among Pacific Gas And Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, The Division Of Ratepayer Advocates, The Utility Reform Network, Green Power Institute, California Large Energy Consumers Association, The California Independent System Operator, The California Wind Energy Association, The California Cogeneration Council, The Sierra Club, Communities For A Better Environment, Pacific Environment, Cogeneration Association Of California, Energy Producers And Users Coalition, Calpine Corporation, Jack Ellis, Genon California North LLC, The Center For Energy Efficiency And Renewable Technologies, The Natural Resource Defense Council, NRG Energy, Inc., The Vote Solar Initiative, And The Western Power Trading Forum.

Assigned Commissioners' Ruling issued on January 18, 2012 in both this proceeding and in A.11-05-023. The other issue was raised by Calpine Corporation (Calpine), and consisted of a proposal to require the utilities to do a solicitation aimed at existing power plants that are operating without contracts. We do not approve Calpine's proposal here.

The proposed settlement has the support of most of the active parties in this proceeding, including parties whose interests are not generally aligned. While not all parties have signed or otherwise endorsed the proposed settlement, no party is actively contesting it. Nevertheless, we must ensure that the proposed settlement is reasonable in light of the whole record, consistent with law, and in the public interest. (Commission's Rule of Practice and Procedure 12.1(d).)[8]

The proposed settlement is, in essence, a punt. The settling parties have agreed to defer determination of the core issue in this proceeding: the utilities' future need for additional generation. To the extent there may be any such need, it appears to be primarily driven by the necessity to integrate higher levels of renewable generation onto the system, in anticipation of a 33% renewable portfolio standard (RPS) target. The settling parties state that: "There is general agreement that further analysis is needed before any renewable integration resource need determination is made." (Settlement Agreement at 5.)

The parties to the proposed settlement describe it as follows:

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[8] Rule 12.1(d) states: "The Commission will not approve settlements, whether contested or uncontested, unless the stipulation or settlement is reasonable in light of the whole record, consistent with law, and in the public interest."

As a compromise among their respective litigation positions, and subject to the recitals and reservations set forth in this Settlement Agreement, the Settling Parties agree that:

• With respect to system resource need and the integration of intermittent renewable resources into the CAISO grid, the Settling Parties encourage the Commission, in conjunction with the CAISO's ongoing work on this subject, to further examine this issue expeditiously in the next Long-Term Procurement Plan (LTPP) cycle or in an extension of the current LTPP cycle.

• All references to a potential "need to add capacity for renewable integration purposes" shall be interpreted within the context of the CAISO process which considers alternatives as further described in Section III.C below to determine the type of resources (including existing units) available to meet any defined needs. There is no presumption that any Phase 1 "need" requires the addition of new gas-fired generation resources above and beyond those needed to meet the current planning reserve margin.

• As requested by the Commission, the CAISO developed a methodology for assessing renewable integration resource needs (the "CAISO methodology"), and applied this methodology with the assistance of the IOUs to assess the need for flexible capacity for the four CPUC-Required Scenarios and one other CPUC scenario analyzed by the CAISO. The results show no need to add capacity for renewable integration purposes above the capacity available in the four scenarios for the planning period addressed in this LTPP cycle (2012-2020). The additional scenario studied by the CAISO did show need.

• The IOUs applied the same CAISO methodology for the IOU Common Scenarios using different assumptions from those used in the CPUC-Required Scenarios. The results of the IOUs' modeling show need for additional capacity for renewable integration purposes under certain circumstances.

- The resource planning analyses presented in this proceeding do not conclusively demonstrate whether or not there is need to add capacity for renewable integration purposes through the year 2020, the period to be addressed during the current LTPP cycle. The Settling Parties have differing views on the input assumptions used in, and conclusions to be drawn from the modeling. There is general agreement that further analysis is needed before any renewable integration resource need determination is made. […] (Settlement Agreement at 4-5.)

In considering the proposed settlement, the first step is to look at whether it is reasonable in light of the whole record. While the substantive issue was not fully litigated, the record is still substantial. The joint testimony of the three utilities is clear that under the four scenarios that the utilities were required to analyze, there is no need for additional generation resources by 2020. (*See* Exhibit 106 at 1-2.) Using other assumptions, however, such as those proposed by the utilities, the modeling did show some potential need. To the extent that there is no need for additional generation resources by 2020, it is clear that the proposed settlement is reasonable, given that it merely defers authorization of generation procurement. If no new generation is needed, then no immediate procurement of generation is needed. On the other hand, if generation is needed by 2020, then deferring procurement of that generation could potentially be problematic.

There is clear evidence on the record that additional generation is not needed by 2020, so there is record support for deferral of procurement. But it is also necessary to ensure that the same conclusion is reached after considering the whole record. It is important to note that the utilities, who are the parties that proposed assumptions that would result in a need for generation by 2020, are themselves actively supporting the settlement. This would indicate that on balance, and despite their litigation position, the utilities believe it is reasonable to defer procurement authorization as the proposed settlement recommends.

In addition, the scenarios under which there is no need for additional generation are the Commission-mandated scenarios, which were developed in a public, collaborative, and iterative process led by Energy Division staff. This would tend to give them more credibility than the alternative assumptions showing need that were proposed by parties as part of their litigation positions.

Finally, a number of parties address this issue in their briefs on the proposed settlement:

> TURN has been monitoring the development of the CAISO methodology for assessing renewable integration resource needs and believes that the model cannot be relied upon to authorize any additional procurement at this time. (The Utility Reform Network (TURN) Opening Brief at 1.)

> In the opinion of the GPI, the overwhelming conclusion of the analyses presented in Testimony by the CAISO and the utilities is that it makes little difference which renewables development trajectory is followed. The costs are all about the same, the environmental improvements are all about the same, and despite the fact that promising new technologies for improving grid operations are left out of the analysis, there is still no identified need for new fossil-fired resources for purposes of renewables integration in any of the PUC-defined scenarios. (Green Power Opening Brief at 15-16.)

> Regarding Track I, CBE is a party to the settlement agreement submitted on August 3, 2011. CBE recommends the Commission approve the proposed settlement. In so doing, CBE requests that the Commission specifically find that the evidence presented in this proceeding does not establish a need for new generation to integrate renewables. CBE further requests that the Commission specifically find that neither Pacific Gas and Electric ("PG&E) nor Southern California Edison ("SCE") have requested or

> established a need for new generation to meet local area need. (Communities for a Better Environment (CBE) Opening Brief at 2.)

While the CAISO Opening Brief supports the proposed settlement, the CAISO attaches to it an internal CAISO memo that would seem to indicate that there is a need for additional generation before 2020. As TURN and the Division of Ratepayer Advocates (DRA) point out, however, this memo is not part of the evidentiary record in this proceeding, and other parties have not had an opportunity to address it. (TURN Reply Brief at 1-2; DRA Reply Brief at 1-4.) Accordingly, we cannot and do not rely upon the memo in reaching our decision.

In looking at the whole record, it would be reasonable to find that there is no need for additional generation by 2020 at this time, and accordingly it is reasonable to defer authorization to procure additional generation based on system and renewable integration need.[9] The proposed settlement is therefore reasonable in light of the whole record.

The next question is whether the proposed settlement is consistent with the law. The substance of the proposed settlement is generally innocuous, as it merely defers a determination by the Commission, and raises no legal issues. Such a deferral is within the authority of the Commission to manage its own proceedings.

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[9] While the focus of this proceeding extends out to 2020, it is important to note that the record similarly does not support a finding of need for additional generation beyond 2020. Accordingly, it is also reasonable to defer procurement of generation for any estimated need after 2020.

Two cautionary notes are appropriate, however. First, the Commission, not the settling parties, determines the schedule and scope of any subsequent proceeding. Even if the parties agree on a particular schedule, the Commission, not the parties, controls the Commission's processes. Because we understand the proposed settlement's discussion of future Commission proceedings to be a recommendation only, the proposed settlement is consistent with the law on this issue.

Second, the parties may not alter the scope of the Commission's jurisdiction by settlement. Because we understand that the parties merely attempted to describe, rather than change, the Commission's jurisdiction, the proposed settlement is consistent with the law on this issue as well.

Finally, we must confirm whether the proposed settlement is in the public interest. Here there is significant public interest in the substance of the settlement – an adequate supply of electricity. Unlike a case of two businesses or individuals arguing about money, public interest is really the central issue. If there is in fact a pressing need for procurement of more generation, approving the settlement and deferring that procurement would not be in the public interest. That determination, however, must be made based upon the record of this proceeding, which in this case means that the analysis of whether the settlement is in the public interest is similar to the above analysis of whether the proposed settlement is reasonable in light of the whole record.

As discussed above, we conclude that it is reasonable to defer authorization of procurement of new generation. Given the record currently before us, deferring procurement of new generation will not cause a problem. The record clearly supports a conclusion that no new generation is needed by

2020, and the record does not clearly support a conclusion that new generation is needed even after 2020.

Deferring authorization for such procurement is not adverse to the public interest, and two additional factors lead to the conclusion that deferring procurement authorization is in the public interest. First, if there is no need to authorize procurement of generation, then there is no need to incur the costs for procurement of generation, meaning that deferral of that procurement results in lower rates. Second, what the parties propose to do with more time – conduct a better analysis of the need for procurement, particularly for renewables integration, with updated information – may provide a significant benefit. Accordingly, we conclude that the proposed settlement's deferral of generation procurement is in the public interest, and we approve the proposed settlement.

Developing the record for future LTPP cycles should utilize processes similar to those used here, including workshops and other public and stakeholder processes that inform and draw input from parties about renewable integration and local area needs. A robust and transparent process is essential to support and develop the complex and sophisticated analyses required, such as the detailed power flow modeling required for determination of local area needs. Given the long-term ramifications that will flow from this or successor proceedings, it is important that the outcome is the result of a solid and credible process.

2.2. SDG&E Local Reliability

SDG&E requested that the Commission authorize 415 megawatts (MW) of new generation to meet its Local Capacity Requirement (LCR). (SDG&E Opening Brief at 11.) Because of transmission constraints, SDG&E notes:

> [E]ven if system-wide studies do not identify a need for additional resources on a statewide basis, there may nevertheless still be a need for new resources to meet local resource adequacy criteria. (*Id*. at 5.)

DRA, Pacific Environment, Natural Resources Defense Council (NRDC), and Sierra Club opposed SDG&E's request. (*See*, DRA Reply Brief at 5-6, Pacific Environment Reply Brief at 7, NRDC Opening Brief at 9, and Sierra Club Reply Brief at 1-3.)

This issue was moved to A.11-05-023 by a Joint Assigned Commissioners' Ruling issued January 18, 2012 in both this proceeding and in A.11-05-023.

2.3. Calpine

Calpine recommends that the Commission direct the utilities to engage in intermediate term (3-5 year) solicitations aimed specifically at existing power plants that do not currently have contracts with the utilities. According to Calpine:

> Current and expected wholesale market conditions do not provide uncontracted existing generation resources with reasonable opportunities to secure sufficient and stable revenue streams to recover going forward costs, including maintenance necessary to ensure availability in the future. As a result, if a procurement mechanism is not adopted in the near term to address this situation, economic retirements should be expected. (Calpine Opening Brief at 3.)

Calpine notes that in this proceeding existing generation has been assumed to remain in operation, but if in fact that existing generation shuts down, then new replacement generation will be needed to meet reliability and renewable integration needs. (*Id*. at 7.)

PG&E, SCE, TURN and DRA oppose Calpine's proposal, arguing that it is not needed, not adequately supported by the record, and it overstates the risk of generation shutdown. (*See*, e.g., PG&E Opening Brief at 13-14, TURN Opening Brief at 2-5.) The CAISO generally supports Calpine's proposal, as the CAISO is concerned by Calpine's prediction of lost generation capacity. (CAISO Opening Brief at 6-8.)

In order to evaluate Calpine's claim, we need to evaluate the potential risks presented. First, what is the actual risk that existing generation will shut down for economic reasons. Second, how much generation would shut down. And third, to the extent that generation does shut down, would that make it permanently unavailable in the future. After evaluating those risks, we need to consider what would be the most appropriate response.

The actual risk of shutdown is difficult to evaluate based on the record. While Calpine owns significant quantities of uncontracted generation, Calpine sought to present its argument as a general problem facing all existing uncontracted generation resources, not just Calpine resources. (Calpine Reply Brief at 8-9.) But Calpine was unable to identify what non-Calpine generation might fit into this category:

> Q So you don't know whether there are any other uncontracted combined cycle units outside of Calpine's fleet?
> A I strongly suspect there are, but I don't know that for a fact. (Calpine witness Barmack, Transcript vol. 6 at 865-866.)

> Q Dr. Barmack, what units other than the Calpine units do you believe are at risk of shutting down?

A It would be purely speculation on my part, but I'm aware of other combined cycles that were built around the same time as many of our units… I'm not aware of whether those units are contracted or not. (*Id.* at 888.)

Alternatively, Calpine could have provided information about the economics of the uncontracted Calpine plants that it asserts are at risk of economic shutdown, but Calpine chose not to do so:

Q So Calpine hasn't provided any information about the cost of operating the existing units in its combined cycle fleet to the Commission in this proceeding, has it?
A No. We haven't provided information about the specific economics of our units. (*Id.* at 851.)

Other than generic market data showing that revenues for combined cycle generation have generally been declining, Calpine presented no evidence to support its claim that its uncontracted generation resources are at risk of shutting down, and it could not even identify any uncontracted non-Calpine generation resources, much less show that they were at risk of economic shutdown.

On the other hand, PG&E points out:

> During cross-examination, Calpine witness Barmack acknowledged that there are significant regulatory limitations on Calpine's ability to retire a power plant. As Dr. Barmack acknowledged, under the Commission's General Order ("GO") 167, Calpine is obligated to maintain its generating units in California in readiness for service unless the Commission, after consultation with the CAISO, affirmatively declares that the units are unneeded during a specified period of time. Moreover, under GO 167, Calpine is obligated to notify the Commission and the CAISO in writing at least 90 day in advance of any planned change in the long term status of any Calpine unit in California. Under the CAISO's tariff, the CAISO has the authority to issue a "risk of retirement" designation to keep a resource in operation that is otherwise at risk of retirement during the current "resource adequacy" year if the CAISO believes the resource will

> be needed for reliability by the end of the following calendar year. Thus, a number of regulatory protections are in place to assure that Calpine's units, if needed for reliability in California, will remain on-line and operational. (PG&E Opening Brief at 13-14.)

We have no specific evidence in the record of this proceeding showing that any combined cycle plants, owned by Calpine or anyone else, are facing a real risk of economic shutdown.[10] Both the Commission and the CAISO have mechanisms to mitigate the risk of one or more power plants shutting down. Even if there is a risk of economic shutdown, we have no record basis to evaluate how much generation could potentially shut down, and whether that would have a significant impact on potential future needs.

Finally, even if there are generation units at risk of economic shutdown, it is not clear that a shutdown would result in those units becoming permanently unavailable. Calpine indicated that it could physically remove components such as combustion turbines and steam turbines for use in other locations. (Transcript vol. 6 at 858-859.) TURN, however, argues that this simply does not make sense, and notes that Calpine could not identify a single instance of any generator shutting down and dismantling a modern combined cycle gas turbine unit in the United States for economic reasons. (TURN Opening Brief at 4-5.) TURN's witness Woodruff noted that other approaches would make more sense:

> Even if the short-term operating economics are unfavorable, Woodruff explains that Calpine has a variety of options

[10] We note that Calpine filed a notice with the Commission under GO 167 on 11/22/11, stating that it intended to retire its Sutter Energy Center generation plant in 2012. Draft Resolution E-4471 orders Calpine not to retire the Sutter plant. http://docs.cpuc.ca.gov/word_pdf/COMMENT_RESOLUTION/157581.pdf.

> including asset sales or temporary shutdown. The notion that Calpine would physically dismantle these units, which is the basis of their request, is simply not credible. (*Id*. at 5.)

Even if we give Calpine the benefit of the doubt on every point, and assume that there is a real risk of the permanent shutdown of a significant quantity of modern combined cycle power plants, it is not clear that Calpine's proposed solution is an appropriate response. Calpine proposes that the utilities be required to engage in a solicitation defined so narrowly that Calpine could be the only bidder. (TURN Opening Brief at 4.) This approach would likely result in Calpine extracting a premium price from the ratepayers of the IOUs. (*Id.*)

Calpine may be correct that there is some level of market failure in the California electricity markets. The current hybrid market structure is an artifact of the ill-fated restructuring of the California electricity markets under Assembly Bill (AB) 1890 and the subsequent California energy crisis, and it is neither elegant nor efficient. Nevertheless, Calpine has failed to show that the specific problem it is complaining about is as imminent or dire as it claims, and it has failed to show that the specific solution it proposes is reasonable. Accordingly, we decline to adopt Calpine's proposal.

3. Rules Track III

3.1. Once-Through Cooling

Many power plants in California use seawater for cooling purposes in a process referred to as once-through cooling (OTC), where water is pulled into the plant's cooling system from the adjacent ocean or estuary, run through the cooling system, and then discharged back into the ocean or estuary, typically at a higher temperature. Unfortunately, this large use of seawater for cooling kills significant amounts of marine life, including larvae, eggs, fish, turtles, and marine mammals.

Accordingly, the California State Water Resources Control Board (SWRCB) has adopted a "Statewide Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling" (OTC Policy). SWRCB describes its OTC Policy:

> The Policy establishes technology-based standards to implement federal Clean Water Act section 316(b) and reduce the harmful effects associated with cooling water intake structures on marine and estuarine life. The Policy applies to the 19 existing power plants (including two nuclear plants) that currently have the ability to withdraw over 15 billion gallons per day from the State's coastal and estuarine waters using a single-pass system, also known as once-through cooling (OTC). Closed-cycle wet cooling has been selected as Best Technology Available (BTA). Permittees must either reduce intake flow and velocity (Track 1) or reduce impacts to aquatic life comparably by other means (Track 2). (from SWRCB website, accessed on November 30, 2011: http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/policy.shtml).

There are multiple means by which a power plant can comply with the OTC Policy:

> Power plant owners/operators can choose how they plan to comply with the Policy's required 93 percent reduction in their use of seawater. Two plants have ceased operation. Most have informed the State Water Board that they are planning to modernize their plants' equipment and will switch to air cooling systems. Some have chosen to use evaporative cooling towers. Others are pursuing alternative controls, such as screening. (SWRCB Fact Sheet at: http://www.swrcb.ca.gov/publications_forms/publications/factsheets/docs/oncethroughcooling0811.pdf, accessed on November 30, 2011.)

The implementation of the OTC Policy has potentially very significant impacts on the operation of the electric system in California. AES Southland describes their situation:

> AES Southland purchased three gas-fired generation facilities from Southern California Edison (SCE) in May 1998: AES Huntington Beach, AES Redondo Beach, and AES Alamitos. (Ex. 1701 at 2 (AES, Didlo).) These three facilities supply 4,140 megawatts of local capacity within the transmission-constrained Western sub-area of the LA Basin Local Capacity Area (LCA). (*Id*.) These generating resources represent 50% of the total net qualifying capacity in the Western sub-area (*Id*. at 3), and were initially built by SCE as part of an integrated urban power delivery system. The concurrent planning of generation stations and transmission lines to minimize urban transmission requirements has created a high level of local dependence on these facilities that effectively utilize the transmission grid to satisfy system reliability. (*Id*. at 5, 6.)
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> Each of the facilities employs once-through cooling (OTC) technology. These facilities are thus subject to the Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (OTC Policy) adopted by the California State Water Resources Control.
>
> Board, and are currently required to comply with the OTC Policy by December 31, 2020. (*Id*. at 1-2). In order to comply with the OTC Policy, AES Southland intends to redevelop its locations by retiring the current operating units and replacing them with state-of-the-art gas turbine technology. (AES Southland Opening Brief at 1-2.)

Because of the potentially far-reaching significance of this new policy, the assigned ALJ determined that the implications of this issue should be addressed concurrently with the System Track I issues.[11] In a later ruling, the assigned ALJ directed the parties to address a staff proposal that would impose limits on the scope of utilities' contracts with power plants subject to the OTC Policy.[12]

The staff proposal would generally prohibit utilities from entering into contracts longer than one year with power plants subject to the OTC Policy, with exceptions for: 1) plants that were found by SWRCB to be in compliance with the applicable requirements of the Clean Water Act; 2) enabling the repowering of the power plant, as long as the contract did not result in operation of the OTC system beyond the applicable SWRCB compliance date; or 3) plants using SWRCB Track 2 alternative compliance mechanisms. (*Id.*, Appendix A.)

Several parties support adoption of the staff proposal. The most detailed argument in support was made by Pacific Environment:

> Staff's proposal to limit the utilities' contracts with OTC facilities to a one-year period is a reasonable attempt to align procurement planning with California's policy of retiring OTC units. Instituting this relatively minor restriction on the duration of OTC contracts is a practical step toward California's goal of OTC phase-out, as set forth in the Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling ("Statewide OTC Policy") adopted by the California State Water Resources Control Board in October of 2010.
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> The Statewide OTC policy directs owners and operators of OTC facilities to comply with one of two compliance alternatives "as

[11] *Administrative Law Judge's Ruling Revising System Track I Schedule*, dated March 10, 2011.

[12] *Administrative Law Judge's Ruling Addressing Motion for Reconsideration, Motion Regarding Track I Schedule, and Rules Track III Issues,* dated June 13, 2011.

> soon as possible, but not later than" their respective compliance dates. Staff's Proposal places workable restrictions on long-term OTC contracting to further the Statewide OTC Policy's of phasing out or repowering OTC units "as soon as possible." No party in this proceeding disputes the propriety of the Statewide OTC Policy or its compliance deadlines. Moreover, most of California's OTC units are aging, inefficient, and unreliable.
>
> Staff's proposal is consistent with the Commission's policy of encouraging the protection of California's water resources. A one-year limit would incentivize and encourage a transition away from aging OTC resources "as soon as possible," consistent with the Statewide OTC Policy. Likewise, the one-year limit will deter utilities from waiting until near the end of the compliance period and subsequently asking for an extension of the shutdown date. (Pacific Environment Opening Brief at 30-31, footnotes omitted.)

CBE supports the idea of limiting utility contracts with OTC units to one year, and argues that doing so "should be uncontroversial," as it would be consistent with the Clean Water Act and the State Water Resources Control Board's stated policy, is sound public policy, and would reduce the likelihood of stranded costs. (CBE Opening Brief at 4-5.) L. Jan Reid (Reid) also supports the proposal. (Reid Opening Brief at 10-11.)

On the other side, the utilities and independent generators, as well as some other parties, oppose the staff proposal. NRG Energy, Inc. (NRG) argues:

> [S]uch artificial restrictions on contracting opportunities would potentially harm the Commission's resource adequacy program, potentially harm system reliability, as well as increase costs to California ratepayers. This proposal is both untimely and unnecessary.
>
> *First*, there is no reason to limit contracting opportunities for OTC plants prior to the compliance dates established by the

SWRCB. Many, if not all, of the compliance dates established by the SWRCB are several years in the future. The one-year limitation on contracting thus serves no useful purpose, because it does not change the dates by which OTC units must comply with SWRCB rules. Further, the phased implementation of the SWRCB's new rules was carefully designed to provide generators time to comply with new rules, while ensuring that the State's environmental goals were accomplished. Adopting the Staff Proposal would upset this careful balance.

Second, limiting the ability of LSEs [load-serving entities] to contract with OTC units is likely to increase the prices such LSEs pay for generating capacity. LSEs routinely enter into multi-year arrangements in order to protect ratepayers against price volatility. Generators also benefit, because these longer term contracts limit their risk, thus promoting lower overall prices. The Staff Proposal, however, would increase prices by increasing the risk to generators, effectively encouraging them to seek higher prices in one-year agreements than they might accept for multi-year agreements. The Proposal would similarly artificially decrease the pool of potential long-term counterparties for LSEs to contract with, thereby making it more difficult for the LSEs to meet their long-term needs on a least-cost basis. The Staff Proposal would thus increase the price LSEs pay for generation while providing little or no environmental benefit.

Third, lack of access to longer-term contracts may lead to decreased system reliability, because longer-term contracts allow for longer-term system planning. There is no question that limiting access to longer-term contracts would increase the uncertainty of future revenue streams for existing OTC generators seeking to comply with the OTC Policy under either Track 1 (replacement by a non-once-through-cooled generation) or Track 2 (mitigation of impingement and entrainment impacts). This uncertainty will manifest itself in higher prices (as discussed above) and also make it difficult for existing units to plan their capital expenditure spending in order to comply with OTC and other environmental rules. (NRG Opening Brief at 2-3.)

Western Power Trading Forum (WPTF) argues that the staff proposal incorrectly presumes that elimination of OTC is the same as actual shutdown of a plant, when in reality the plant owners are more likely to consider potential alternatives that would keep a plant operating, or reliability concerns will result in the plant continuing to operate. This last scenario seems to imply that the plants would continue to operate with OTC, despite the SWRCB's OTC Policy. (WPTF Opening Brief at 4.)

PG&E argues that the most appropriate way to address OTC in contracting is to take a plant's OTC status into consideration in the RFO evaluation process. Plants using OTC would receive a low environmental score, making them less attractive. (Ex. 107 at 1-3.)

SDG&E and DRA suggest a modification of the staff proposal, so that instead of a default one-year limit, the utilities could not sign contracts with OTC units that would extend beyond the OTC unit's SWRCB compliance deadline. While opposing the staff proposal, SDG&E stated that:

> … SDG&E does not oppose the proposal to limit the IOUs' ability to enter into contracts that would require operation of an OTC facility beyond the compliance date…(SDG&E Opening Brief at 22.)

Similarly, DRA stated that:

> Therefore, DRA recommends that the rule be that utilities may not enter into contracts with any OTC facility that would extend beyond the final date the facility is scheduled to retire or repower under the SWRCB policy statement. If a counter-party can demonstrate that the OTC facility will continue to operate and be in compliance with SWRCB requirements after its compliance deadline, this restriction should not apply. (DRA Opening Brief at 26.)

A number of parties, however, point out that the question of contracting with OTC units is quite complex, as the transition away from OTC can be accomplished in multiple ways, and may have very different ramifications depending on variables including the location of the plant, the selected compliance method, and future developments. For example, California Large Energy Consumers Association (CLECA) stated:

> CLECA pointed out that the problem is not the length of the contracts. [citation omitted] It is how to prepare for the retirement or repowering of these units in the context of making cost-effective decisions to address local reliability needs given the SWRCB regulations. CLECA notes that the Settlement in Track 1 of this proceeding provides a plan to assess these local reliability needs over the next year. The Commission should consider the results of that assessment before reaching any decision on contracting for the output of fossil OTC units. (CLECA Opening Brief at 5-6.)

Likewise, WPTF recommends:

> Rather than limiting contracts with OTC units to one year, the Commission should focus its OTC policy consideration on examining the need for replacement capacity, as discussed below. Indeed, it may be the award of a multi-year contract that provides the financial underpinnings that will enable an OTC unit to invest in an upgrade of its cooling facilities to become compliant with the OTC regulations, or perhaps undertake an even more extensive repowering.
>
> […]
>
> The CAISO is engaged in studies to assess the impact of OTC retirements consistent with the SWRCB's policy. WPTF recommends that the Commission should await the final results from the studies before making any determinations as to the need for replacement capacity associated with OTC retirements. (WPTF Opening Brief at 5.)

And GenOn California North LLC (GenOn) recommends:

> Finally, in light of the further needs analysis contemplated by the Settlement Agreement, and the CAISO's focus on evaluating how OTC compliance deadlines affect the need for new capacity to meet LCR, the Commission should allow parties to make policy recommendations regarding the replacement of OTC facilities in the next phase of this proceeding. It is difficult to make cogent recommendations regarding what types of procurement policies are needed to support OTC goals until the CAISO' s additional study results are known. As the understanding of the impacts of OTC retirements becomes more complete, policy choices that are not readily apparent today may become more apparent then. (GenOn Opening Brief at 2-3.)

As an interim measure to provide short-term clarity and procurement authority to the utilities, while supporting the SWRCB policy of moving away from OTC, we will adopt a variation of the SDG&E and DRA approach. The utilities are authorized to sign power purchase agreements with power plants using OTC, but those agreements may not commit to purchases beyond the applicable SWRCB compliance deadline, except under the specific conditions described below. In addition, consistent with PG&E's recommendation, the applicable RFO or other solicitation evaluation must take into consideration the plant's use of OTC.

Power purchase agreements with plants using OTC with a contract duration of two years or less are subject to the Commission's standard procurement rules. If, however, the power purchase agreement terminates one year of less prior to the applicable SWRCB compliance deadline, that agreement must be submitted to the Commission for approval via a Tier 3 advice letter.

OTC power purchase agreements with a contract duration of more than two years but less than five years must be submitted to the Commission for approval via a Tier 3 advice letter. In order to provide guidance to Energy Division in evaluating these agreements and the utilities in preparing and submitting these agreements, the applicable criteria shall include the following: 1) how the contract helps facilitate compliance with the SWRCB OTC policy, or at a minimum why it does not delay compliance; 2) the expected operation of the OTC facility under normal load (1 in 2) and high load (1 in 10) conditions, including number of starts and run time after each start; 3) the LCR net position with and without the OTC facility over the contract duration and two years beyond the contract duration; and 4) how any other available generation resources compare under these criteria.

OTC power purchase agreements with a contract duration of five years or more must be submitted to the Commission for approval via an application, consistent with normal procurement rules.

For any agreements that terminate one year or less prior to the applicable SWRCB compliance deadline, the advice letter or application must specifically show how the agreement helps facilitate compliance with the SWRCB policy regarding OTC.

Generators and utilities may be able to develop contracts that facilitate the modification of a unit to eliminate the use of OTC, or to otherwise bring it into compliance with SWRCB OTC policy. For example, it may be appropriate for such contracts (but not non-compliant OTC operation) to extend beyond the SWRCB OTC compliance date, giving the plant owner a revenue stream that would continue after the plant is modified to eliminate its use of OTC or otherwise comply with SWRCB requirements. At the same time, we do not want to create an incentive to prolong the plant's use of non-compliant OTC.

To balance these factors, we will allow contracts to extend beyond the SWRCB OTC compliance date, but only if such contracts: 1) allow for utility purchase or receipt of power generated by a unit using non-compliant OTC only up to the SWRCB OTC policy compliance date in effect on the date the contract is signed. The contract shall not allow the utility to continue to purchase or receive power generated using non-compliant OTC beyond that date even if SWRCB extends the compliance date; 2) protect utility ratepayers against stranded costs; 3) protect ratepayers against the risk of future unspecified cost increases resulting from increases in the cost of the generation unit compliance with the SWRCB OTC policy. For a utility to recover such cost increases from ratepayers, it must obtain the necessary approval from the Commission; 4) are consistent with a need authorization from the System Track of the LTPP proceeding; and 5) are consistent with other procurement rules, including this decision's requirement to file either a Tier 3 Advice Letter or an application. Any such advice letter or application must show compliance with all relevant SWRCB policies and regulations, and also must show how the contract provides or facilitates cost-effective and reliable service.

This is necessarily an interim approach, and as recommended by a number of parties, OTC issues will be examined further, either in a later phase of this proceeding or in a successor proceeding.

3.2. SCE Generation Auction Proposal

In the portion of its Opening Brief relating to OTC issues, SCE describes its proposal for its "New Generation Auction Mechanism":

> Exhibit 211, at pp. 4-9, describes SCE's proposal that the Commission open a new proceeding to address a new generation procurement method for new capacity for replacement of OTC generation or meet renewable integration needs required to

> maintain reliability of the electric grid in the future. SCE proposed a "CAISO new generation auction to commence the debate on the appropriate mechanism to meet the new generation need." (SCE Opening Brief at 14.)

SCE's proposal is strongly criticized by a number of parties, including TURN, DRA and the Large-scale Solar Association (LSA). DRA and LSA argue that SCE's proposal is at best premature, and more significantly, that the focus and scope of the proceeding proposed by SCE would prejudge the outcome of that proceeding. (DRA Reply Brief at 14, LSA Opening Brief at 13.) TURN argues that SCE's proposal would undercut ratepayer protections, is disingenuous in its attempt to hide its potential impacts, and the proceeding would divert time, energy and resources away from more pressing issues. (TURN Reply Brief at 6-7.)

First, we note that the potential ramifications of this issue are significantly broader than the OTC issue that SCE attempts to shoehorn it into. Second, we agree with DRA and LSA that the focus and scope of the proposed proceeding, as defined by SCE, is too prescriptive, and would tend to inappropriately prejudge the outcome. To the extent that the Commission chooses to open a rulemaking proceeding to address the possible issues identified by SCE, the Commission, not SCE, will determine the focus and scope of that proceeding. SCE's proposal for the Commission to open a proceeding to address SCE's proposed new generation auction mechanism is denied.

3.3. UOG v. PPA

Under our current electricity market structure, the utilities purchase power from independent generators under power purchase agreements (PPAs), and also generate power at utility-owned generation facilities (UOG). UOG facilities may either be constructed by the utility itself, or purchased by the utility. These different sources of electricity tend to be difficult to compare, particularly in the context of evaluating competing bids.

Utility procurement of power from third parties is often obtained by means of competitive utility RFOs, to which competing providers respond by submitting offers or bids. A number of (usually disparate) parties tend to agree that it is not possible to fairly compare UOG and PPA projects in an RFO. SCE "believes that proposed UOG projects should not be considered in an IOU's competitive bid solicitation because they are fundamentally different from PPAs." (SCE Opening Brief at 22.) Pacific Environment generally agrees with SCE on this issue, and identifies a number of the differences between UOG and PPA projects. (Pacific Environment Opening Brief at 42-44.)

As WPTF explains in more detail:

> There are very real problems associated with evaluating UOG proposals in competition with PPA bids. The uneven life cycles of PPA contract periods (traditionally ten years) are shorter than the life of a UOG asset, which inevitably tilts any discounted cash flow analysis in favor of the longer lived UOG assets. PPAs and UOG also have very different risk profiles, with UOG having assurance of ratepayer cost recovery while PPA project sponsors must factor a return into their bids. And of course, UOG projects enhance utility profits through additions to rate base, whereas PPAs do not. An RFO that requires comparisons of UOG versus PPA projects is neither credible nor manageable. Finally, and of equal importance, having the IOUs in a position to evaluate their own UOG projects in comparison to PPA bids creates a very real perception of bias that in turn compromises the competitiveness of the RFO. (WPTF Opening Brief at 6.)

The issue here is how to best address this disparity, with the caveat that this decision does not apply to UOG that is a "proposed eligible renewable energy resource" under Section 399.14.[13]

In 2004, this Commission took a relatively structured approach that required all resources (including UOG) to go through the RFO process, but that also attempted to put utility shareholders, rather than ratepayers, at risk for UOG resources. This was intended to equalize the allocation of risk between UOG and PPA projects and to impose "market discipline" on utility bids in the RFO process, and was to be accomplished by capping UOG costs at their initially bid capital cost. If actual UOG costs turned out to be less than bid, the savings would be shared 50/50 between ratepayers and shareholders. (D.04-12-048 at 140-141.) In 2007, we modified that approach, eliminating the cost cap and the sharing mechanism, and moving to a more flexible, case-by-case approach. (D.07-12-052 at 221.)

Some parties assert that the current process adequately addresses the issue, and need not be modified at this time. (*See*, e.g., SDG&E Opening Brief at 25-26, 29.) Other parties propose new and very specific approaches. The Independent Energy Producers Association (IEP), for example, spells out in some detail problems with the existing system, and presents a new approach, including a "bid evaluation algorithm." (IEP Opening Brief at 1-33.)

Our current approach has some merits, as did our prior approach, but it is not clear that either one proved to be fully satisfactory. IEP's more detailed approach also has its potential benefits, but it is not clear that it is ready for

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[13] Issues relating to UOG "proposed eligible renewable energy resources" are more appropriately addressed in the RPS Rulemaking, R.11-05-005.

implementation in its current formulation. Rather than attempt wholesale revision of the current rules, we will endeavor to refine them here. Accordingly, we leave in place the existing rules except as modified by this decision.

First, we agree with WPTF and SCE that it is inappropriate to have UOG projects participate in utility generation RFOs. Even if theoretically it might possible to have a utility-owned project compete fairly in a utility-run RFO, in practice it will never look fair. In particular, any time that a utility-owned project is selected in such an RFO, it will give an appearance of favoritism. Regardless of how fair an RFO was, if it looks like the one competitor had an inside track or that the judging was baised, some of the benefits of using an RFO are largely eviscerated. Potential participants may try to avoid that market, which is not a desirable outcome in the context of electricity procurement. PG&E argues that an RFO for both UOG and PPA can be fair, and that PG&E has shown that it can be fair. (PG&E Opening Brief at 19.) But PG&E's example has not resolved this issue, nor ameliorated all concerns.

Accordingly, the utilities should continue to use RFOs for non-UOG procurement, consistent with prior Commission decisions, but UOG procurement will be done through the certificate of public convenience and necessity (CPCN) process.

Nevertheless, it is still necessary for the Commission to be able to fairly compare the costs of UOG and PPA projects, even if they are not in a single RFO, as the Commission continues to have a duty to assure just and reasonable rates. The Commission needs to know that if there is a choice of generation sources, that it is authorizing the most appropriate one(s).

In order to achieve this, the Commission needs to make sure that it has a basis for at least a general comparison of UOG and PPA resources. RFOs tend to have standardized (or at least known) criteria, and (hopefully) result in multiple bids with relatively fixed terms, making the resulting contracts easier for the Commission to evaluate. UOG projects, on the other hand, tend to be more unique, as well as having more open-ended and changeable terms. Accordingly, it is most appropriate to look at the criteria used for reviewing UOG projects.

DRA recommends that for bid assessment purposes, UOG project costs should be amortized over the same term as a PPA, due to the indefinite lifespan of a UOG project, compared to the finite term of a PPA. (DRA Opening Brief at 32.) IEP makes a similar proposal that in the bid evaluation process the period of levelization for independent power producer contracts should be the same as the period of levelization assumed for a UOG project. (IEP Opening Brief at 24.) PG&E uses a levelized value approach. (PG&E Opening Brief at 20.)

These are potentially useful tools that the Commission could use to compare UOG and PPA projects. It would be reasonable for a utility to include the results of these types of analysis when proposing UOG projects to the Commission. If the utility does not provide these analyses with its application, the utility shall provide such analyses and any supporting data upon the request of the assigned ALJ or Energy Division staff.

IEP also proposed that:

> [T]he Commission should bar utilities from imposing arbitrary or discriminatory limits on the contract term that IPPs can propose. If a UOG is evaluated on the basis of its 30-year useful life, IPPs should be allowed to propose PPAs with terms of up to 30 years. If IPP PPAs are limited to 10 years, then UOG projects should be evaluated as if cost recovery is limited to 10 years. (*Id.*)

We decline to make this more radical change at this time. DRA makes another proposal that attempts to address the same issue:

> DRA recommends that the Commission provide specific guidance to the IOUs on what input assumptions or forward cost curves are reasonable to use for UOG valuations. This guidance should be developed and vetted through a public stakeholder process held at the Commission. This guidance will help to level the playing field for comparing UOG and PPA bids. (DRA Opening Brief at 33.)

The Commission may provide specific guidance regarding what input assumptions or forward cost curves should be used for UOG valuations. The Commission may choose to develop that guidance through a stakeholder process, or it may just rely upon the expertise of Commission staff.

IEP also makes another proposal, that for bid evaluation purposes the cost of UOG project and bid development should be included. (IEP Opening Brief at 22.) SCE agrees with this, stating:

> The costs of developing a specific UOG project are included in the cost estimate for the project, and will be part of the project costs which the Commission considers in the CPCN and reasonableness review processes for UOG. (SCE Opening Brief at 24-25.)

We agree. In evaluating UOG proposals, the Commission should consider all of the project costs, and the utilities should include project development costs in their requests for acquiring UOG facilities, as well as for utility-constructed ones. If an independent developer wants utility ratepayers to pay for costs, such as planning, design, and project development, it must include those costs in its bid. If a utility did not include those cost in its bid, but recovered their costs in general rate case operating costs, the utility would be getting a ratepayer-funded cross-subsidy of its project that is unavailable to the independent developer, that would result in an unfair comparison of what appear to be project costs.

Some parties proposed that utility shareholder money be at risk for the costs of preparing unsuccessful UOG proposals. (DRA Opening Brief at 34, WPTF Opening Brief at 11.) This recommendation appears to apply only in the case of UOG participation in RFOs. Because we are not permitting UOG participation in utility RFOs, we decline to adopt this proposal.

TURN has a recommendation that it claims would improve the ability to compare the relative value of UOG and PPAs:

> The Commission should require that the critical cost parameters of any UOG bid should be binding on the IOU for the first ten years of project operations. "Critical cost parameters" include initial capital costs, capital additions, fixed and variable O&M, and heat rates. TURN witness Woodruff explains that this requirement is appropriate because of "the potential for the costs of UOG resources to escalate from those upon which the evaluation and selection was based." Given the typical treatment for UOG resources, in which IOUs are not held to forecasts of cost or performance after the project achieves initial commercial operation, the Commission must take action to create real accountability so the original selection process is not unfairly biased in favor of UOG.
>
> Absent this type of accountability, IOUs have an incentive to assume superior long term cost and performance advantages of UOG projects. Since the Commission rarely, if ever, revisits these initial assumptions, there is no penalty to making overly optimistic projections that are never realized. Even if they are revisited, the IOU need only demonstrate that the costs are reasonable at the time they are incurred. The absence of any accountability mechanism only emboldens IOUs to game this process to the benefit of shareholders and the detriment of ratepayers.
>
> TURN encourages the Commission to adopt this general principle in this proceeding and leave the details to any utility-

specific application seeking approval of a UOG project. (TURN Opening Brief at 7-8.)

DRA makes a similar recommendation:

[T]hat the Commission establish hard cost caps for capital costs and Operation & Maintenance (O&M) for UOG projects, so that the IOUs will not underbid these costs and then attempt to recover higher costs after the UOG project has been approved. (DRA Opening Brief at 33.)

SDG&E opposes this approach:

DRA points out that UOG *can* be compared with IPP PPAs, but recommends certain modifications to the bid evaluation process. Most notably, DRA proposes that in approving UOG projects, the Commission should cap recovery of capital costs and operations & maintenance ("O&M") costs at the level included in the UOG bid. In general, SDG&E does not object to the proposal to cap recovery of capital costs, provided that the IOUs have the right to file an Application to recover additional costs in the event capital costs exceed the amount included in the UOG bid. This approach is fair and is analogous with Commission treatment of IPP requests to re-price PPAs. With regard to O&M costs, however, DRA's proposal is not workable.

Under SDG&E's GRC [General Rate Case] cost recovery methodology, ratepayer risk is capped on an aggregate basis rather than a project-specific basis. The O&M revenue requirement, for example, is expressed as a *total* amount that covers all O&M costs – an O&M cost on one project that is below what was forecasted may offset a cost overrun on a different project. If aggregate costs exceed the O&M revenue requirement, shareholders are at risk for the excess O&M amount. Thus, because the GRC cost recovery methodology does not contemplate project-specific O&M price caps, the Commission should not adopt DRA's O&M cost cap proposal. (SDG&E Reply Brief at 32-33, footnotes omitted.)

TURN, DRA, and SDG&E all raise issues related to ensuring that there is a fair comparison of UOG and PPA generation resources. For the reasons stated by TURN and DRA, TURN's recommendation is a reasonable approach to equalize the playing field between UOG and PPA, and the Commission will apply that principle in utility applications for UOG projects.

SDG&E points out that for capital costs, generators may request to have PPAs re-priced, so it would be reasonable to allow UOG facilities the same relief. This makes sense, and reinforces the idea that the ability to recover capital costs in rates should be parallel for UOG and PPAs. In general, under traditional ratemaking practices once UOG facilities are put into rate base, the utility is guaranteed rate recovery, even if the plant is no longer needed, fails to operate properly, or is somehow destroyed (through no fault of the utility). PPAs with independent generators may not provide the plant owner or operator the same level of assurance of rate recovery of capital costs. We will not order the utilities to enter into PPAs that provide the same certainty of rate recovery as given to UOG facilities, but the utilities may wish to align the capital cost recovery terms of any proposed UOG projects with those typically applicable to PPAs.

SDG&E's argument relating to O&M costs also raises an issue of comparability. SDG&E points out that its O&M costs from multiple facilities are considered on an aggregated basis, rather than on an individual project basis. It is unlikely that independent generators can aggregate O&M costs in this same manner; instead they receive one payment stream specifically for one project's O&M. For consistency, new UOG projects would need to be segregated from pre-existing facilities' O&M, and not aggregated with the new O&M for multiple new UOG projects.

Assuming that the source of SDG&E's GRC cost recovery methodology was this Commission,[14] this Commission can modify that methodology. We do not do so here, but if a UOG project is proposed, it is within the Commission's authority to apply a project-specific O&M cost cap. Again, utilities proposing UOG projects may want to align the O&M cost recovery terms for their project with those typically applicable to PPAs.

WPTF argues that a utility should not be able to unilaterally choose to seek authorization for a UOG project, but can only seek a CPCN for a UOG project when there has been a failed competitive solicitation, with that result confirmed by the RFO's independent evaluator. (WPTF Opening Brief at 9-10.) This would give the first opportunity for meeting need to an open and competitive process, and only if that process cannot deliver what the utility needs can the utility resort to seeking authorization for UOG. WPTF argues that the Commission should adopt the following policy:

> UOG offers shall not be considered in RFOs. Rather, utility-owned projects shall be proposed to the Commission via traditional applications for a certificate of public convenience and necessity only when and if a competitive solicitation has failed. (*Id.*)

DRA, while assuming that UOG will participate in RFOs, makes a fundamentally similar recommendation, that all UOG proposals should be "tested" through a competitive solicitation or RFO process. (DRA Opening Brief at 30-31.) According to DRA, this would allow the Commission to determine if a particular UOG proposal is in fact a good deal for ratepayers. (*Id.*)

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[14] SDG&E provides no citation for this issue.

SCE opposes WPTF's recommendation that a UOG application be preceded by an RFO. While SCE may seek authority for UOG as a result of a failed RFO, it also just wants to be able to just seek authorization in those situations it deems to be appropriate for UOG. (SCE Opening Brief at 24.) SCE argues that:

> Under the current rules, the utility will have already have to show that a competitive process was not feasible or appropriate in its application, and the Commission can then determine whether the utility's case is compelling. (*Id.*)

While such a showing would continue to be necessary, even under the WPTF approach, DRA points out that this existing process has not been effectively applied. (DRA Opening Brief at 31.) We understand that requiring an RFO prior to submitting a CPCN application for a UOG project potentially adds an additional step, but it should significantly increase the transparency of the procurement process, and provide useful information to the Commission regarding the viability of competitive options to a UOG project.

We adopt the WPTF recommendation on this issue. One aspect that is not adequately fleshed out, however, is the criteria to be applied in determining whether or not an RFO has "failed." Because of the lack of record on this issue, we will provide only general guidance in how such a determination should be made, and the Commission may modify or otherwise revisit this approach in future LTPP proceedings.

If a utility believes that an RFO has failed, before it may file an application for a UOG project, a utility must submit a Tier 3 advice letter, setting forth the reasons why the RFO should be considered "failed."[15] There are a number of factors that the Commission will consider in making a determination that an RFO has failed. A threshold issue would be a determination that the RFO was fair, and not overly prescriptive, as there is no point in having RFOs that are "designed to fail." In addition to the determination that an RFO was fair, other factors to be considered include the number of offers submitted in response to the RFO, the quality of those offers and how closely the products offered correspond to the requirements of the RFO, the price and related terms of the offers, and the viability of the proposed projects. The Commission may also take other factors into consideration. Once the Commission has issued a resolution determining that an RFO has failed, the utility may submit an application for a UOG project.

3.4. Utility RFO Timelines

One issue identified in the March 10, 2011 Ruling as being appropriately addressed in Track III was described as "refinements to the existing timelines associated with the utilities' RFOs for resource adequacy products." (March 10 Ruling, supra at 4.) This issue was raised by the Alliance for Retail Energy Markets (AReM) in their pre-hearing conference statement of February 23, 2011.

Neither AReM nor any other proponent of AReM's position submitted testimony or briefing on this issue. The only testimony on this issue was from utilities opposed to AReM's proposal. SDG&E argues that the current practice is consistent with previous Commission decisions and is based on sound policy and practice, and there is no need for change. (SDG&E Opening Brief at 29-31,

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[15] One such reason might be the utility's good faith belief that a specific UOG proposal would provide greater ratepayer benefit than any of the offers in the RFO.

citing to Exhibit 313.) SDG&E correctly observes that: "No evidence that would justify a departure from the current process and timeline for the IOUs' RFOs for RA has been offered into the record of this proceeding." (*Id.* at 31.)

Given the state of the record on this issue, we decline to modify the current practice in this area.

3.5. Greenhouse Gas Product Procurement

The utilities argue that it is necessary for them to procure greenhouse gas compliance instruments in order to comply with the new cap-and-trade program being implemented by the California Air Resources Board (CARB). (*See* SDG&E Opening Brief at 15-17.) Greenhouse gas compliance instruments, which are also sometimes referred to as greenhouse gas-related products or greenhouse gas products, consist primarily of allowances and offsets that the utilities must procure in order to meet their compliance obligations under the cap-and-trade program.

During the course of the proceeding there was some uncertainty as to when CARB's cap-and-trade program would effectively begin, and accordingly there was some debate about when the Commission needed to authorize utility procurement of greenhouse gas compliance instruments. (*See*, DRA Opening Brief at 13-14.) That uncertainty appears to have largely been resolved, and while some parties suggest minor delays, we find it reasonable to authorize the utilities to begin procuring greenhouse gas compliance instruments at this time. We accordingly approve the utilities' greenhouse gas compliance instrument procurement plans as modified by this decision.

The issues we need to address here are: 1) what types of compliance instruments the utilities should be authorized to procure; 2) how and where the utilities procure their compliance instruments; and 3) what quantities of compliance instruments the utilities may procure.

The first issue is to identify the types of compliance instruments the utilities should be procuring. The potential compliance instruments include allowances, offsets, and derivative products of each, such as futures, options, and swaps. Utility use of allowances is relatively uncontroversial. Allowances are issued by CARB, and as described by Sierra Club, "…represent authorization to emit a specified amount of pollution during the compliance period…" (Sierra Club Opening Brief at 10.) While there was some debate about the details of utility procurement of allowances, there was no significant opposition to the basic premise that allowances are an appropriate means for the utilities to comply with CARB's requirements. The utilities are authorized to procure allowances issued by CARB.

By comparison, the proposed use of offsets is more controversial. Offsets are purchased from third parties, not from CARB, and present some different issues than do allowances. As SCE states:

> CARB's cap-and-trade program authorizes IOUs to meet a portion of their greenhouse gas compliance obligation through the purchase of offsets that comport with CARB's previously-approved offset protocols. [fn. omitted] Offsets will only be certified as compliant after the fact, that is, once the GHG emission reduction has taken place and has been verified. Once an offset is certified, it can be used to fulfill a compliance obligation. However, unlike an allowance, a CARB-certified offset may have its CARB certification revoked. This revocation can occur even after the offset was accepted by CARB for a compliance obligation, if it was later found to have been certified erroneously, under false pretenses, or if the project from which the offset was derived did not meet CARB's permanence requirement. (SCE Ex. 210 at 6.)

The parties vary widely in their positions on the use of offsets. PG&E largely does not distinguish between allowances and offsets in its procurement plan, but rather treats the two as interchangeable. (*See* Exhibit 107-C, Chapter 3.) SCE's observation that offsets, unlike allowances, may not achieve certification, or even if certified may have their certification revoked, leads SCE to the conclusion that offsets will be less valuable than allowances, and that offsets will trade at a discount to allowances. SCE proposes to procure not only CARB-certified offsets, but also offsets that "SCE reasonably believes will be certified" by CARB. (Ex. 210, supra.)

Sierra Club opposes any use of offsets by the utilities on two grounds. First, Sierra Club argues that the use of offsets is bad policy, because: "[T]he use of offsets also has environmental consequences by lowering the cost of compliance with the cap and trade program under AB 32, thereby undermining the incentive to pursue emission reduction projects at the IOUs' capped sources." And second, they argue that the Commission should not authorize the use of offsets without first performing an analysis under the California Environmental Quality Act (CEQA). (Sierra Club Opening Brief at 13-19.)

We note that allowances and offsets are in fact different creatures. As SCE observes, allowances must be certified, and there is no guarantee that they will be certified, or even that that they will retain their certification. This issue of validity does not exist for allowances. In addition, under CARB regulations, utilities can only meet up to 8% of their compliance obligation through use of valid offsets. (*See*, SCE Opening Brief at 10, Pacific Environment Opening Brief at 25-27.)

Sierra Club argues against the use of offsets:

> By reducing the cost of compliance, offsets have environmental impacts by making emission reduction projects at capped IOU sources less desirable. Every ton of offsets claimed is a ton of emission reductions that IOUs do not have to achieve. There will be less incentive to explore alternatives that reduce demand (e.g., energy efficiency, demand response) or reduce emissions (e.g., increased renewable generation or repowering or replacement of inefficient generators). (Sierra Club Opening Brief at 12.)

From a ratepayer perspective, reducing the utilities' cost of compliance would be a good thing. As a Commission we are certainly interested in reducing environmental impacts, and we have strong policies in place to encourage energy efficiency, demand response, and renewable generation. We reiterated our commitment to the loading order in this proceeding in D.12-01-033. We are not depending on high greenhouse gas compliance costs to drive these otherwise desirable programs. In addition, SDG&E points out that Sierra Club may be trying to relitigate an issue that has essentially been decided by CARB. (SDG&E Reply Brief at 31.)

Sierra Club's argument that reducing the cost of greenhouse gas compliance would compromise other environmentally beneficial programs is unpersuasive, and we decline to second-guess CARB on the appropriate level of offsets that can count towards compliance.

At this time it is most appropriate to make sure that the utilities' procurement of offsets is consistent with CARB's approach. Accordingly, each utility may purchase no more than 8% of their compliance requirement in the form of offsets, provided these purchases also stay within the overall greenhouse gas compliance product procurement limits identified below. All offsets must be CARB-certified, as at this time we do not want the utilities guessing which offsets will ultimately be CARB-certified. This decision does not authorize the utilities to develop their own offset projects. To the extent any utility wishes to develop an offset project, it must seek authorization from this Commission via application.

Because existing offsets, unlike allowances, face the risk of being invalidated if CARB finds they do not meet measurement or verification requirements, there is a question of who bears the risk of invalidation. The default under CARB regulations is that the responsibility for invalidated offsets falls on the buying entity. In order to protect ratepayers against this risk, the utilities can only purchase offsets if the purchase contract requires the seller to assume the risk of invalidation and to post appropriate collateral. (PG&E Comments at 8.)

Pacific Environment argues that because of the increased risks of offsets, and their potential for controversy, the utilities should be required to file advice letters for each category of offsets they propose to use. (Pacific Environment Opening Brief at 25-26.)

The utilities oppose Pacific Environment's proposal, but appear to interpret it as requiring an advice letter for each individual offset transaction, rather than for each category of offset. (*See*, PG&E Reply Brief at 15, SCE Reply Brief at 7.)[16] We agree that an advice letter for each offset transaction does not appear to be necessary. It would potentially be useful for the Commission to know what types of offsets the utilities are purchasing, however, particularly if they are purchasing a new type for the first time. Pacific Environment's specific

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16 This confusion is understandable, as the section heading appears to indicate that an advice letter would be required for each transaction.

proposal is not clear, but it appears that Pacific Environment would have the utilities submit advice letters if they were to procure outside the current CARB-approved categories of "…livestock manure projects, urban forest projects, U.S. ozone depleting substances projects, and U.S. forest projects." (Pacific Environment Opening Brief at 26.)

Since CARB approval of any additional categories should be public knowledge, and the utilities may only procure CARB-certified offsets, a general advice letter informing the Commission that the utility intended to purchase offsets in the new category would appear to offer relatively little value. Accordingly we decline to adopt Pacific Environment's advice letter process at this time. We may, however, consider a more refined proposal in the future.

Sierra Club argues that Commission approval of utility use of offsets may have a significant effect on the environment, and therefore the Commission is required to perform a CEQA review before authorizing the utilities to procure offsets for compliance purposes. (Sierra Club Opening Brief at 15-19.) There are a number of problems with Sierra Club's argument.

First, as pointed out by the utilities, CARB already performed an environmental review of its entire cap-and-trade program, including the use of offsets.[17] (SCE Reply Brief at 10-11; PG&E Reply Brief at 16-18.) Even if Sierra Club does not like CARB's analysis, or thinks it is inadequate (Sierra Club Opening Brief at 18), that does not mean that this Commission should perform another (duplicative and time consuming) CEQA review. (CEQA Guidelines

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[17] Pursuant to its certified regulatory program, CARB prepared a "Functional Equivalent Document," (FED) as authorized by Pub. Resources Code section 21080.5.

15003(g) and 15006(m).) Sierra Club's arguments are simply inconsistent with CEQA.

Second, the substance of Sierra Club's argument that offsets will result in a significant environmental impact misstates the applicable standard. Sierra Club argues:

> The action for which the IOUs seek approval constitutes a "project" because it would allow the IOUs to engage in an activity that may cause a direct or reasonably foreseeable indirect physical change to the environment. Offsets in the AB 32 cap and trade program not only impact the environment by allowing covered sources to avoid making greenhouse gas emission reductions, but they represent projects that themselves can have environmental impacts. Currently, CARB has identified four categories of projects that can generate offsets: livestock manure (digester) projects; urban forest projects; ozone depleting substances projects; and U.S. forest projects. *See,* e.g., Ex. 313 at 7. <u>These offset projects will undeniably effect the environment in ways that are different than reducing emissions from capped sources</u>. The two forestry offset options do not involve controlling emissions at all, but instead give credit to the creation of emission "sinks" that have the potential to absorb the increased greenhouse gas emissions that would be allowed. *See* CARB, "Functional Equivalent Document Prepared for the California Cap and Trade Regulation," Appendix O, at 271-337 (Oct. 28, 2010) (available at: <u>http://www.arb.ca.gov/regact/2010/capandtrade10/capv5appo.pdf)</u>. It is also beyond dispute that <u>the environmental impacts of reducing emissions from livestock manure operations will be different than the impacts of reducing emissions at capped IOU sources</u>. *Id.* at 235-270. Cross-examination of IOU experts affirmed the differing environmental impacts of reducing capped emissions and using offsets instead. *See,* e.g., Cross-Examination of Mr. Miller, SDG&E, Trans. at 805 (agreeing that "[i]t would make sense" that the environmental impacts would be different). (Sierra Club Opening Brief at 16, emphasis added.)

Sierra Club's main point is that the potential use of offsets to reduce greenhouse gases would affect the environment differently than the potential use of allowances to reduce greenhouse gases, and therefore the Commission's authorization of the use of offsets would have a significant impact on the environment. But this is not how a significant impact is determined under CEQA. Even if Sierra Club is right that allowances are in some way "better" than offsets, that is not the analysis required by CEQA. The proper analysis for determining whether a project will have a significant impact is by looking to see whether approval of the project will have a significant impact when compared with currently existing conditions, not with some hypothetical other possibility. (CEQA Guideline 15125(a); *Communities for a Better Environment v. South Coast Air Quality Management District, et. al.*, 48 Cal. 4th 310 (2010).[18]

In addition, it is not clear exactly what environmental review Sierra Club is arguing that the Commission should perform, if any. In its Opening and Reply Briefs, Sierra Club never specifies whether the Commission should act as a lead agency, and accordingly perform a complete new review, or as a responsible agency, and rely upon CARB's analysis. In its Opening Brief, Sierra Club's argument implies that the Commission should act as lead agency:

> Thus, there is more than a fair argument that the approval of offsets will have significant environmental impacts. [citation omitted] As such, an environmental analysis of the proposed action as well as consideration of alternatives and mitigation

[18] Sierra Club is misapplying the criteria for evaluating alternatives in an Environmental Impact Report (EIR) under CEQA, where the lead agency will examine different approaches (CEQA Guideline 15126.6), to the threshold question of whether there is a significant impact on the environment (CEQA Guideline 15064).

> measures must be prepared before making any decisions. (Sierra Club Opening Brief at 18.)

But since the Commission is only authorizing participation in a previously reviewed and approved CARB program, such an "environmental analysis" would be duplicative of that already performed by CARB. There is no good reason why the Commission should redo CARB's environmental analysis, particularly for allowing participation in a CARB program. We decline to second-guess CARB's environmental analysis merely because Sierra Club does not like its results.

In its Reply Brief, Sierra Club acknowledges that: "[T]here may be some opportunity to 'tier' a new environmental analysis off of the work the Air Resources Board has already completed…" (Sierra Club Reply Brief at 4.) The CEQA Guidelines define tiering:

> "Tiering" refers to using the analysis of general matters contained in a broader EIR (such as one prepared for a general plan or policy statement) with later EIRs and negative declarations on narrower projects; incorporating by reference the general discussions from the broader EIR; and concentrating the later EIR or negative declaration solely on the issues specific to the later project. (CEQA Guideline 15152(a).)

To the extent that the Commission approves specific offset projects, the Commission will consider tiering off the CARB document as appropriate. For example, if the utilities want Commission authorization to develop offset projects, they need to file an application with this Commission, at which time this Commission would perform the appropriate project-level CEQA review.

Here, however, there is no need to tier additional analysis off the CARB analysis because we are not approving anything different than what CARB has reviewed and approved. In short, there is nothing additional to tier. This is clear from the CEQA Guidelines on tiering:

> (d) Where an EIR has been prepared and certified for a program, plan, policy, or ordinance consistent with the requirements of this section, any lead agency for a later project pursuant to or consistent with the program, plan, policy, or ordinance should limit the EIR or negative declaration on the later project to effects which:
>
> (1) Were not examined as significant effects on the environment in the prior EIR; or
>
> (2) Are susceptible to substantial reduction or avoidance by the choice of specific revisions in the project, by the imposition of conditions, or other means. (CEQA Guideline 15152 (d).)

In this decision the Commission is only authorizing the utilities to participate in CARB's previously-approved program; the utilities are not authorized to go beyond the scope of that program, nor are they authorized to develop their own offset projects.

If, despite Sierra Club's apparent position that the Commission should act as lead agency, the Commission were to act as a responsible agency on this issue, it is not clear how that could be done. A responsible agency does not perform a new environmental review, but rather would consider a previously prepared environmental document, such as the FED prepared by CARB, and make any necessary findings based on that document. (CEQA Guidelines 15096 and 15253.) This would not appear to satisfy Sierra Club's request for a new analysis, particularly since they argue that CARB's analysis "does not pass legal muster." (Sierra Club Opening Brief at 18.)

In addition, CARB performed an environmental analysis of its entire cap-and-trade program, not just the offset portion, and we are authorizing the utilities to participate in that entire program, not just the offset portion. Under normal responsible agency practice, this Commission would have to review the entire greenhouse gas program, not just the offset portion. Yet Sierra Club insists that the Commission only look at the offset portion of the program, and in fact insists that the Commission use the allowance portion of the greenhouse gas program as the baseline against which the Commission would evaluate the offset portion of that same program. It would be impossible for the Commission to perform the analysis requested by Sierra Club as a responsible agency under CEQA.

Finally, Sierra Club argues that the Commission should defer its approval of utility procurement of offsets (Sierra Club Reply Brief at 4-5), and that the Commission cannot approve utility procurement of offsets based on the current record. (*Id*. at 3.) From Sierra Club's shotgun approach, and its attempts to use CEQA-based arguments that are actually contrary to CEQA, it would appear that SDG&E is correct in its observation that Sierra Club is trying to relitigate an issue that it lost at CARB. (SDG&E Reply Brief at 31.) Sierra Club may also be attempting to reverse a prior decision of this Commission that established our fundamental policy on this issue. In our 2008 decision, this Commission endorsed both the use of offsets and a quantitative cap like that adopted by CARB. (D.08-10-037 at 272-274.) The ill-fitting CEQA arguments presented by Sierra Club do not disguise what are actually collateral attacks on the substance of prior decisions of CARB and this Commission. CEQA does not require an additional environmental review by this Commission, and it certainly does not require the Commission to act as lead agency on a duplicate CEQA review of the offset portion of CARB's cap-and-trade program.

In addition to allowances and offsets, it is likely that derivative products, such as futures, forwards, options, and swaps, will become increasingly available in the near future. According to its testimony, PG&E is only seeking authority to obtain allowances and offsets. (Exhibit 107 at 3-3 and 3-9.) SDG&E, on the other hand, indicates that it may seek to purchase financial swaps and options. (Exhibit 313 at 7-8.) In order to ensure consistency and to reduce ratepayer exposure to risks in the nascent California greenhouse gas market, we will limit the use of derivative products at this time.

Allowance futures and forward contracts, where a utility contracts for delivery of CARB-issued allowances at a future date, would provide utilities with actual compliance instruments in a relatively direct manner.[19] (Ex. 313 at 7-8.) While there may be some added risk in the case of forwards if the third party fails to deliver, we will allow the utilities to procure allowances via forward contracts. To mitigate default risk, the utilities should apply their standard procurement credit and collateral requirements to these transactions, and may also impose additional credit and collateral requirements as appropriate. To the degree futures become available via exchanges, the utilities may procure them subject to the process described below regarding procurement of greenhouse gas compliance products via exchanges. Any allowance futures or forward contracts entered into by the utilities will count against the applicable quantity limitations described below.

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[19] In discussing forwards, we are considering them to be an obligation to deliver actual allowances, rather than a financial obligation. (Ex. 313 at 8.)

Given the risk inherent in offsets, the additional risk of purchasing other derivative products, and the limited amount of offsets that can be used for compliance, we are concerned whether there is enough potential benefit to justify the utilities' purchase of offset futures or forwards.

For offset forwards, it appears possible to limit the risk, as forward contracts can be structured so that the purchasing utility only pays for the offsets after they are certified and received by the utility. (PG&E Comments at 8, DRA Comments at 4-5.) In effect, the utilities would be purchasing certified offsets. Accordingly, as long as the utilities structure their contracts in this manner, they are authorized to procure offset forwards. Such protection is not readily available for offset futures, so the utilities may not purchase offset futures or enter into contracts for the purchase of offset futures.

Options and swaps, while they may ultimately result in the utility procuring a compliance product, are more removed, and tend to have more value in price hedging than in procurement. (Ex. 313 at 8.) Accordingly, the utilities may not procure options, swaps, or other derivatives of greenhouse gas compliance instruments. As the market in greenhouse gas products develops further, we may reconsider these limitations.

In addition to specifying which greenhouse gas compliance instruments the utilities are authorized to procure, we also need to consider the means by which the utilities obtain these instruments. The goals here are to ensure that the counterparties the utilities are buying from are sound and legitimate sellers who will deliver the purchased compliance products, and that the prices paid by the utilities for those products are reasonable.

All utilities expect to procure allowances from CARB via CARB-run auctions and from the CARB's Allowance Price Containment Reserve (*See*, e.g.

Exhibit 107 at 3-4; Exhibit 313 at 8-10.) The utilities are authorized to procure allowances from CARB via a CARB auction or other CARB process.

In addition to the CARB, there will be other possible sources of allowances and offsets, particularly as the market develops further. These include exchanges, brokers, and bilateral transactions. As the market develops, there may be a liquid and transparent market in greenhouse gas compliance products, but the record does not currently support such a finding. Nevertheless, we are approving utility procurement of greenhouse gas compliance products now, as the utilities will need to acquire them. We do not want to overly restrict the utilities' ability to procure the necessary compliance products, but we do need to ensure that utility procurement of greenhouse gas compliance products is done in a way that results in achievement of utility compliance obligations at reasonable cost.

Accordingly, we will impose some requirements on how and where the utilities may procure compliance instruments. As stated above, all utilities may procure allowances from CARB. To the extent that the utilities wish to procure authorized compliance instruments via bilateral transactions (including brokers), the utilities must utilize a competitive RFO process, consult with their procurement review group (PRG), apply their approved procurement credit and collateral requirements, and apply the applicable affiliate transaction rules. In short, the bilateral procurement of greenhouse gas compliance instruments follows a process similar to procurement of generation resources.

In theory, exchanges provide for liquidity and price transparency. In practice, it is not yet clear how well exchanges for California greenhouse gas compliance instruments will function. It is our hope that functional and liquid exchanges will develop quickly, and accordingly we will allow the utilities to procure greenhouse gas compliance instruments on Commission-approved exchanges.

We note that the utilities currently engage in power procurement activities on Commission-approved exchanges. We will allow the utilities to procure greenhouse gas compliance instruments on exchanges that the Commission has previously approved for power procurement. (PG&E Comments at 9.)

For exchanges that the Commission has not previously approved for power procurement, the utilities must, prior to purchasing greenhouse gas compliance instruments on that exchange, obtain one-time Commission approval for use of that exchange by submitting a Tier 2 advice letter detailing: 1) what exchange they are seeking to use; 2) the liquidity and transparency of the exchange, specifically for California greenhouse gas compliance instruments, including an explanation of how the Commission can be assured that the price of products procured on the exchange is reasonable; and 3) the regulatory authority or authorities the exchange is subject to.

The next issue is the quantity of compliance instruments the utilities can procure. If the utilities procure too much, they will have unnecessarily spent ratepayer money buying something they may not need. If the utilities procure too little, they run the risk of incurring a penalty, or scrambling to procure at the last minute, which could result in ratepayers paying a premium price if the market price is high.

The primary purpose for procuring compliance instruments is to ensure that the utilities are in compliance with CARB's regulations regarding greenhouse gas, and this Commission has a duty to ensure that they comply in a manner which does not expose ratepayers to unnecessary carbon price risks. Accordingly, at this time, while the market for greenhouse gas compliance instruments is still new, the utilities need to focus on procurement for compliance purposes. Utilities should not be procuring greenhouse gas compliance instruments for speculation.

At the same time, however, SCE points out that it (perhaps more than the other utilities) bears not just responsibility for its direct compliance obligation, but also faces financial exposure to greenhouse gas costs through the market prices it pays for energy, which will reflect the greenhouse gas compliance costs of the generators. (SCE Comments at 6-7.)

Regardless of whether we are considering the direct compliance obligation of a utility or its potential financial exposure to greenhouse gas compliance costs, we do not want the utilities to over-procure, with the hope of selling any excess at a profit, or under-procure, with the hope prices will be low for last-minute purchases. But since CARB's cap and trade regulations allow early year vintages to be banked and used to cover subsequent year's emissions, some over-procurement as part of a "buy and hold" approach may not be inherently problematic. Similarly, if actual emissions turn out to be lower than forecast, it may turn out that the utilities have over-procured. In such a situation, it may be beneficial to ratepayers and to the market for the utilities to sell allowances or other compliance instruments. Accordingly, we do not attempt to strictly limit procurement quantities to those needed for compliance, and we will allow the utilities to resell greenhouse gas compliance instruments without obtaining prior Commission approval. The utilities should, however, report any such sales to their PRG.

In their confidential testimony, all three utilities have proposed limits on the quantity of compliance instruments that they can either purchase or hold. (Exhibits 107-C, 210-C and 313-C.) Some of these limits consist of bands, with minimum and maximum levels of procurement around a target, while others consist of just maximum levels that the utility may purchase or hold. (*Id.*)

Our goal here is to provide the utilities reasonable flexibility in procurement and the ability to respond to market conditions, while limiting potential ratepayer exposure. The band approach appears to be a good way to balance these factors, as setting minimum and maximum levels of greenhouse gas compliance instrument procurement would spread the cost risk across multiple years. While the utilities should be motivated to reduce the overall costs of complying with CARB's cap and trade program, procurement limits help to bound ratepayers' cost exposure. Minimum levels of procurement prevent the utilities from waiting until the final year within a compliance period to procure the necessary instruments and the corresponding risk of price increases. Similarly, maximums ensure that the utilities do not over-procure in early years, and lose opportunities to procure compliance instruments in later years at potentially lower prices.

However, as pointed out by several parties, the applicable CARB regulations have effectively set a minimum procurement level, as the utilities are required to annually surrender compliance instruments sufficient to cover at least 30% of their annual compliance obligation. (*See*, e.g., PG&E Comments at 6.) Should CARB change this requirement, this Commission may revisit the desirability of minimum procurement levels.

Consistent with these general concepts, we establish two discrete approaches to provide the utilities with greenhouse gas compliance instrument procurement authority. One addresses the utilities' direct compliance obligation along with their obligation to procure instruments on behalf of an entity, such as a generator, that has a greenhouse gas compliance obligation. The second addresses the utilities' procurement of greenhouse gas compliance instruments as a means of limiting their exposure to greenhouse gas compliance costs resulting from their purchase of energy. We establish separate purchase limits for each category. In any given compliance year, the utilities may purchase authorized greenhouse gas compliance instruments up to the specified limits.

The Direct Compliance Obligation Purchase Limit is calculated as set forth in Appendix 1. The approach we adopt provides the utilities broad latitude, particularly giving them the opportunity to forward procure to the degree they believe compliance instrument prices are favorable, or to postpone procurement to when they believe pricing will become more favorable.

When the utilities update their procurement plans in conformance with this decision, they should provide an estimated forecast of the amount of greenhouse gas compliance instruments (in metric tons CO2 equivalents) that corresponds with the limits established under the above formula. The utilities may update their greenhouse gas compliance forecasts (and corresponding purchase limits) as necessary via a Tier 2 advice letter. The advice letter shall include a description and workpapers detailing the calculation of the estimated purchase limits and an explanation of the key drivers of differences from the prior estimates. Forecast updates and corresponding revisions to the purchase limits, along with all greenhouse gas compliance instrument transactions, shall be reported at each utility's quarterly PRG meetings and Quarterly Compliance Reports. The cost incurred for the greenhouse gas compliance instrument transactions should be included in each utility's Energy Resource Recovery Account filing for cost recovery.

In addition to the above Direct Compliance Obligation Purchase Limit, we also establish a Financial Exposure Purchase Limit on the procurement authority of the utilities for purchases intended to hedge their potential exposure to greenhouse gas compliance costs from market purchases where those costs are embedded in the price of energy. The arguments in support of this authority were primarily raised by SCE, which argued that it had greater exposure to these costs than the other utilities. (*See*, SCE Comments at 6-7.)

As a result, SCE takes a different approach than the other utilities, and requests authority to engage in much more aggressive procurement (and corresponding sales) of greenhouse gas compliance instruments than the other utilities, primarily for price hedging purposes. Because the greenhouse gas market is very new, and the record analysis on this issue could use more development, we are reluctant to provide the utilities the broad latitude requested by SCE. Because some procurement to address financial risk is reasonable, we grant the utilities additional leeway to enter into transactions for greenhouse gas compliance instruments as a means of hedging their greenhouse gas cost risk, but not the expansive authority that SCE requested. Accordingly, the Financial Exposure Purchase Limit is calculated as set forth in Appendix 1.

When the utilities update their procurement plans in conformance with this decision, they should provide an estimated forecast of the amount of greenhouse gas compliance instruments (in metric tons CO2 equivalents) that corresponds with the limits established under the above formula. The utilities may update their greenhouse gas compliance forecasts (and corresponding purchase limits) as necessary via a Tier 2 advice letter, ideally the same advice letter submitted for updating the purchase limits associated with the direct compliance obligations. The advice letter shall include a description and workpapers detailing the calculation of the estimated purchase limits and an explanation of the key drivers of differences from the prior estimates. Forecast updates and corresponding revisions to the purchase limits, along with all greenhouse gas compliance instrument transactions, shall be reported at each utility's quarterly PRG meetings and Quarterly Compliance Reports. The cost incurred for the greenhouse gas compliance instrument transactions should be included in each utility's Energy Resource Recovery Account filing for cost recovery.

In general, greenhouse gas compliance instrument procurement is an area in which both the utilities and the Commission are on the steep part of the learning curve, and will need to adapt as the functioning of the greenhouse gas compliance market develops. Parties may accordingly raise issues relating to procurement of greenhouse gas compliance instruments in the next LTPP proceeding.

3.6. IEP Motion

In a motion filed on September 23, 2011, IEP noted that some independent power producers entered into PPAs prior to the enactment of AB 32, and those PPAs do not include mechanisms to cover the cost of CARB's cap-and-trade regulations implementing AB 32. (IEP Motion at 1-2.) According to IEP, this issue appears to be unlikely to be resolved by CARB at this time. (*Id*. at 2-3.) Based on the language in an August 4, 2011 Joint Ruling in this proceeding and in the Utility greenhouse gas Cost and Revenue Rulemaking (R.) 11-03-012, IEP requests that this issue be addressed and resolved in this proceeding.

Specifically, IEP requests that this Commission, on an expedited basis, make a:

> [D]etermination of the treatment of GHG compliance costs associated with contracts executed between independent generators and utilities prior to the passage of AB 32 that do not

include a mechanism for recovery of such costs. (IEP Motion at 3.)

Parties representing independent power generators filed responses in support of IEP's position, and a number of independent generators moved to intervene in this proceeding specifically to support IEP's Motion. (*See*, Motions for Party Status of Wellhead Electric Company, Inc.; Starwood Power Midway, LLC; ACE Cogeneration Company; and Rio Bravo.) These parties set forth in some detail the potential problems they face if they cannot recover their AB 32 compliance costs, and their unsuccessful efforts to get CARB to address this issue to their satisfaction. The independent generators argue that it is unfair that generators who signed contracts after the passage of AB 32 can recover their greenhouse gas compliance costs, while generators who signed contracts prior to AB32 cannot recover those costs.

SCE opposes the IEP Motion on two grounds. First, SCE notes that contracts with qualifying facilities (QFs) are subject to the QF/combined heat and power (CHP) Settlement approved in D.10-12-035, and that settlement addresses greenhouse gas compliance costs. (SCE Response at 1-3.) Second, SCE argues that for non-QF contracts, the issue of greenhouse gas cost recovery is more appropriately addressed at the Federal Energy Regulatory Commission (FERC), rather than at the CPUC. (*Id*. at 3-5.)

Because of the timing of when this issue arose, it was not addressed in testimony or evidentiary hearings in this proceeding. The record on this issue consists solely of IEP's Motion and the responses to that motion.

As a threshold matter, we agree with SCE that we are not modifying the terms of our approval of the QF/CHP Settlement in D.10-12-035. Contracts that are subject to that settlement should be addressing greenhouse gas compliance costs consistent with that decision, and need not be addressed again here. There are, however, contracts with non-QF independent generators that are not covered by that settlement, and we do need to address this issue regarding those generators.[20]

As a general matter, the independent generators are correct that it appears somewhat arbitrary and unfair for the recovery of greenhouse gas compliance costs to vary between otherwise similarly-situated generators based on whether the applicable contract was signed before or after the passage of AB 32. At the same time, contracts negotiated and executed when AB 32 was working its way through the legislature should have taken the potential impacts of AB 32 into consideration. Even those negotiating contracts shortly before then might also have reasonably foreseen that this issue could arise.

In D.08-10-037, we emphasized the importance of treating all market participants equitably and fairly, and reiterated our statement in D.08-03-018 that, "[I]t is not our intent to treat any market participants unfairly based on their past investments or decisions made prior to the passage of AB 32." (D.08-10-037 at 144-145, citing D.08-03-018 at 18.) While we do not need to treat everyone identically, and we are not in the business of bailing unregulated market participants out from their own past missteps, this fundamental concept still holds true: we do not want to inadvertently create or maintain unfair competitive impacts.

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[20] SCE makes legal and jurisdictional arguments that this Commission has no authority to even consider this issue. We note that the other parties have not had an opportunity to respond to these arguments. But even on the limited record before us on this issue, we do not believe that the legal issues are as clear-cut as SCE asserts.

The parties should be able to renegotiate any contracts that currently do not address the allocation of AB 32 compliance costs, so that the contracts are modified to be consistent with Commission policy. Rather than rewrite the existing contracts based on the limited record before us, we direct the utilities to renegotiate the contracts at issue so that they reasonably address the allocation of AB 32 compliance costs. Because of the limited record we have on this issue, we do not prejudge how the contracts should be modified, as we believe the parties are in a better position to address that issue, including questions of whether the existing contract may have taken the passage of AB 32 into consideration.

If the contracts have not been renegotiated and submitted to the Commission for approval 60 days from the effective date of this decision, the Commission will address and resolve this issue in R.11-03-012.[21]

3.7. Rulebook

The final Rules Track III issue to be addressed at this time is the Energy Division proposal to adopt certain procurement oversight rules, sometimes referred to as a "Rulebook." The Rulebook proposal was developed from the prior Commission LTPP decision (D.07-12-052 at 222-228), plus a 2010 workshop and party comments. (*See*, June 13, 2011 Ruling, supra, Appendix B.) In those comments, parties generally expressed a preference for a Rulebook that would be primarily for reference purposes only, containing a summary of existing Commission procurement rules. As proposed by Energy Division, however, the Rulebook would not just be a reference compendium, but rather would itself be a fully enforceable document, similar to a General Order of the Commission. (*Id.*)

[21] The Commission may also choose to address this issue in this proceeding or a successor proceeding.

While some parties expressed support for specific rules contained in the Rulebook, all parties that addressed the nature of the Rulebook itself opposed the proposal to make it a fully enforceable document. (*See*, Opening Briefs of PG&E, SCE, SDG&E, the Center for Energy Efficiency and Renewable Technologies (CEERT), DRA, Reid, Pacific Environment, Cogeneration Association of California (CAC) and Energy Producers and Users Coalition (EPUC).) Accordingly, at this time we do not adopt the Rulebook as a stand-alone enforceable document. But it does make sense to have a single set of clear procurement rules in one place, rather than spread out through a series of decisions. How exactly this is best accomplished – Rulebook, General Order, superseding Decision, or otherwise – we defer to future LTPP proceedings. For now, we will limit our actions to addressing certain of the specific rule changes proposed in this proceeding.

The first rule change relates to the Quarterly Compliance Reports that the utilities submit to the Commission. In D.07-12-052, we stated that:

> The Commission currently requires each IOU to submit a Quarterly Compliance Report (QCR) via the Commission's advice letter process within 30 days of the end of every calendar quarter, in order for Commission Staff to review the IOU's procurement transactions for compliance with the Commission-approved procurement plan and its up-front and achievable standards and criteria. (*Id*. at 185.)

The Commission staff review is currently performed by the Commission's auditing staff, bringing that review (and any resulting report) under the purview of General Order 66-C, and accordingly limiting its public disclosure.

Energy Division staff has proposed that the QCR audit reports be made public. (June 13, 2011 Ruling, Appendix B.) SCE opposes this proposal, while Pacific Environment generally supports increased transparency in procurement practices. (Pacific Environment Reply Brief at 9-11.) The staff proposal to make QCR audit reports public is consistent with our goals to increase the transparency of the Commission's processes, while still protecting confidential information. Accordingly, we adopt the staff proposal to make QCR audit reports public.

All three utilities argue that if this proposal is adopted, then the final QCR audit report issued by staff include, in the body of the report itself, the utility's response or rebuttal to that report:

> PG&E recommends that if this proposal is adopted, the Staff report include both the audit findings and the IOU response to those findings in a single document. (PG&E Opening Brief at 34.)
>
> If there are any audit observations or discrepancies that cannot be resolved between the audit staff and the utility, the utility may submit a rebuttal that is incorporated into the final audit report, and which may also include the utility's original general comments. (SCE Opening Brief at 34.)
>
> While SDG&E does not oppose making QCR audit reports public, it recommends that the Energy Division be required to include in the body of the QCR audit report the IOU's comments in response to the findings set forth in such audit report – this should be required in *all* instances, not merely when discrepancies exist. (SDG&E Opening Brief at 40-41.)

The QCR audit report is a Commission staff product, so it is not clear that a utility's response or rebuttal to that report should be placed in the audit report itself. Doing so could be misleading, as it could make it appear that the audit report itself adopts or approves of the utility response. Since the audit reports will be published by posting them on the Commission's website, it is sufficient that a link to any utility response or rebuttal on the utility's website be posted on the Commission website with the audit report. We decline to require that the utility response or rebuttal to the audit report be placed in the body of the report.

The second rule change relates to the processes of the utilities' PRGs. The Commission previously established PRGs that review the utilities' procurement strategy, processes, and specific transactions, and provide non-binding recommendations to the utility on their procurement activities. In D.07-12-052, we directed the utilities to prepare PRG meeting summaries, and to distribute those summaries to the members of the PRG. (D.07-12-052 at 124.)

Staff has proposed that those meeting summaries be distributed by e-mail to the members of the PRG within 14 calendar days of the PRG meeting. (June 13, 2011 Ruling, Appendix B.) PG&E offers an alternative proposal that PRG meeting summaries would be provided 48 hours in advance of the next PRG meeting. According to PG&E,

> This is sufficient time for PRG members to review the summaries in advance of the meeting, but also allows the flexibility for the development of meeting summaries if PRG meetings are close in time or involve more complicated summaries that require sufficient time to prepare. (PG&E Opening Brief at 34.)

SDG&E opposes the proposal, arguing that it makes available other materials, such as agendas of meeting topics and detailed presentation materials. (SDG&E Opening Brief at 37-38.) As described in its brief, SDG&E's practice does not appear to comply with D.07-12-052.

We will adopt the staff proposal that meeting summaries be distributed no later than 14 days after the PRG meeting, with caveats based on PG&E's comments. First, the meeting summary should be distributed on the earlier of 1) 14 days after the PRG meeting, or 2) 48 hours before the next regularly scheduled PRG meeting. If, due to unusual circumstances, 14 days will be inadequate time to prepare a meeting summary, the utility may distribute it 21 days after the PRG meeting, but may do so only if it sends an e-mail to the same distribution list seven days after the PRG meeting informing them of the delay in distribution.

There are a number of proposed rules that relate to the appropriate role of the Independent Evaluator (IE). The Commission has required the utilities to use IEs in RFO solicitations to ensure a fair and competitive procurement process. (*See* D.07-12-052 at 134-139.) Some of the proposed rules are intended to maintain or protect the independence of the IE, but others are just cleanup measures based on the Commission's experience to date.

On the cleanup side, one proposal is that any public IE reports be identical to the corresponding confidential IE report, except for the redaction of confidential material. This is a simple approach to help ensure that the public and confidential versions of an IE report do not give differing impressions, or inadvertently contradict each other. It is the same approach that the Commission generally uses for testimony and briefs in its proceedings. We adopt this proposal, with the clarification that public versions must show where redactions have been made, and confidential versions must show which parts are redacted from the public versions.

Another proposed cleanup measure is:

> New IE report filing requirement: For solicitations of products five years or greater in length, the IE report shall be filed with Energy Division and the PRG at least 7 calendar days before any IOU application is filed with the CPUC and the IE report should also be submitted as an attachment to the application. (June 13, 2011 Ruling, Appendix B.)

SDG&E opposes this proposal, on the grounds that it would cause needless delay. According to SDG&E, the IE's solicitation report cannot be completed until after contract negotiations are completed, so an application will be almost complete by the time the IE report would be ready to be filed. SDG&E recommends keeping the current practice of filing the IE report with the application. (SDG&E Opening Brief at 38.)

While it would be useful for the Commission to have the IE report in advance of the application, it is not clear that seven days is enough in advance to actually make a difference (or that it would cause any significant delay). If the Commission received the IE report 20 or 30 days before the application, that might be more useful, but could also result in some delay in filing if the application was ready to be filed at the time the IE report was available. At this time we will leave in place the existing requirement that IE reports be filed with the corresponding application.

A number of parties support the proposal to have the Commission's Energy Division, rather than the utilities, oversee the hiring and oversight of IEs. DRA recommends that instead of the current practice of IEs being selected and hired by the utilities, the Commission's Energy Division should select, contract, hire and manage the IEs. DRA argues that the current system has inherent conflicts of interest that have the potential to undermine the impartiality of the IE, and may create an appearance of impropriety. (DRA Opening Brief at 27-28.) WPTF, TURN and Pacific Environment make essentially similar arguments. (WPTF Opening Brief at 15, TURN Opening Brief at 8-9, Pacific Environment Opening Brief at 46-48.)

PG&E supports this proposal, with certain caveats to ensure that the process of state contracting does not create delays, and that the IE selected is qualified for the specific task. (PG&E Reply Brief at 21.) SDG&E opposes the proposal, arguing that it is unnecessary, and could inject "unnecessary bureaucracy and delay" into the procurement process. (SDG&E Reply Brief at 40-42.)

This issue was raised in our previous LTPP proceeding, and was addressed in D.07-12-052. In that decision, we stated: "At this time, it is not practical to transfer the IE contracting authority to the Commission; however, we will continue to explore ways in which to do so in the future." (*Id*. at 136.) Unfortunately, that appears to remain the case, as there do in fact seem to be practical and administrative hurdles to overcome. We agree that it would be preferable for IEs to be hired by and report to the Commission, rather than the utilities, and to the extent the barriers to doing so can be overcome in the future, we will consider this proposal again.

We do not adopt any other of the proposed changes to the procurement rules at this time, but we may consider additional changes in future proceedings.

4. Comments on Proposed Decision

The proposed decision of assigned ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on March 12, 2012, and reply comments were filed on March 19, 2012.

In response to comments, substantive changes were made in the areas of utility contracting with plants using once-through cooling, and utility procurement of greenhouse gas compliance instruments.

Reid and Women's Energy Matters argue that the proposed decision should have addressed issues they raised relating to the continued use of nuclear power. While issues relating to the need for various generation resources are appropriate to address in an LTPP proceeding, those issues have been deferred as a result of the settlement, and accordingly it is reasonable to not address them in this decision.

The California Association of Small and Multi-Jurisdictional Utilities (CASMU), consisting of Pacific Power, Bear Valley Electric Service and California Pacific Electric Company, argues that the proposed decision's requirements relating to the procurement of greenhouse gas compliance instruments should not apply to them, as they are structured and regulated differently than the three major utilities. We concur, as this proceeding focused upon the three major utilities. Because CASMU did not actively participate in this proceeding, we have no record on which to base a decision. Accordingly, this decision neither authorizes any procurement by the small and multi-jurisdictional utilities, nor does it independently require the small and multi-jurisdictional utilities to follow the conditions imposed on the major utilities' procurement activities. Any existing procurement authority (and any conditions on that authority) remains in effect, and any modifications to that authority should be requested in a proceeding that is specifically applicable to the small and multi-jurisdictional utilities.

5. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Peter V. Allen is the assigned ALJ in this proceeding.

Findings of Fact

1. The proposed settlement deferring a determination on the issue of the utilities' need for additional electric generation is supported by most of the parties to this proceeding.

2. The proposed settlement is reasonable in light of the whole record, consistent with law, and in the public interest.

3. Calpine did not present evidence on the specific economics of its generation facilities to support its proposal for utility solicitations aimed at existing power plants without contracts.

4. Calpine did not identify any non-Calpine combined-cycle generation facilities that are operating without contracts.

5. The California SWRCB has adopted regulations limiting the use of OTC by electric generation facilities.

6. Utility procurement of electricity from generation facilities using OTC should be consistent with the SWRCB regulations, and should encourage the operators of those generation facilities to comply with the regulations.

7. SCE's proposed new proceeding to address a new generation auction mechanism is unnecessary, and its focus and scope are inappropriate.

8. It is difficult to compare the cost and value of UOG facilities with independently-owned generation facilities.

9. UOG participating in a utility-run RFO creates an appearance of unfairness.

10. An open and competitive RFO process for generation is desirable.

11. UOG may be necessary if suitable independently-owned generation is not available.

12. The utilities need to procure greenhouse gas compliance products to comply with CARB's implementation of a greenhouse gas cap-and-trade program.

13. The greenhouse gas compliance products procured by the utilities should ensure their compliance with CARB's program at a reasonable cost and low risk to ratepayers.

14. The default under CARB regulations is that the responsibility for invalidated offsets falls on the buying entity.

15. Some contracts between independent generators and the utilities that were executed prior to the passage of AB 32 do not address cost recovery for greenhouse gas compliance costs, and are not addressed by the QF/CHP Settlement.

16. The rules relating to utility procurement of electricity could benefit from continued adjustment and refinement.

17. It would be good practice to have a single set of procurement rules in one place, but many parties opposed the rulebook proposal presented in this proceeding.

Conclusions of Law

1. The proposed settlement meets the requirements of Commission Rule 12.1(d), and should be approved.

2. Calpine failed to present adequate evidence to support its proposal for utility solicitations aimed at existing power plants without contracts.

3. Utility procurement of electricity from generation facilities using once-through cooling should be structured to result in compliance with the SWRCB regulations regarding OTC.

4. The Commission should not open a new proceeding to examine SCE's proposed new generation auction mechanism.

5. UOG should not compete with independently-owned generation in a utility-run RFO.

6. In considering UOG, the Commission should use criteria to fairly compare it with independently-owned generation.

7. UOG should be considered only after an RFO for independent generation has failed.

8. The utilities should be allowed to procure certain greenhouse gas compliance instruments at this time, specifically allowances, allowance forwards and futures, and offsets and offset forwards.

9. To reduce risk to ratepayers, the quantities and sources of greenhouse gas compliance instruments procured by the utilities should be limited.

10. It would be desirable for contracts between independent generators and the utilities to address cost recovery for AB 32 greenhouse gas compliance costs, but the record in this proceeding does not support a Commission-ordered resolution at this time.

11. It is reasonable to adopt certain refinements and clarifications of the utilities' electric procurement rules.

O R D E R

IT IS ORDERED that:

1. The Proposed Settlement, as attached to the August 3, 2011, Motion For Expedited Suspension Of Track 1 Schedule, And For Approval Of Settlement Agreement Between And Among Pacific Gas And Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, The Division Of Ratepayer Advocates, The Utility Reform Network, Green Power Institute, California Large Energy Consumers Association, The California Independent System Operator, The California Wind Energy Association, The California

Cogeneration Council, The Sierra Club, Communities For A Better Environment, Pacific Environment, Cogeneration Association Of California, Energy Producers And Users Coalition, Calpine Corporation, Jack Ellis, Genon California North LLC, The Center For Energy Efficiency And Renewable Technologies, The Natural Resource Defense Council, NRG Energy, Inc., The Vote Solar Initiative, And The Western Power Trading Forum is approved.

2. Calpine Corporation's proposal for the utilities to conduct solicitations aimed at existing power plants without contracts is not approved.

3. a. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) are authorized to sign power purchase agreements with power plants using once-through cooling, but those agreements may not commit to purchases beyond the applicable State Water Resources Control Board compliance deadline, and those agreements must be submitted to the Commission for approval via a Tier 3 advice letter for contracts of more than two years but less than five years, or via an application for contracts with a duration of five years or more. In addition, the applicable request for offers or other solicitation evaluation must take into consideration the plant's use of once-through cooling.

b. If such agreements terminate one year or less prior to the applicable State Water Resources Control Board compliance deadline, the advice letter or application must specifically show how the agreement helps facilitate compliance with the State Water Resources Control Board policy regarding once-through cooling.

c. PG&E, SCE, and SDG&E contracts with facilities utilizing once-through cooling may extend beyond the State Water Resources Control Board once-through cooling compliance date, but only if such contracts: 1) Allow for utility purchase or receipt of power generated by a unit using non-compliant once-through cooling only up to the State Water Resources Control Board once-through cooling policy compliance date in effect on the date the contract is signed. The contract shall not allow PG&E, SCE, and SDG&E to continue to purchase or receive power generated using non-compliant once-through cooling beyond that date even if the State Water Resources Control Board extends the compliance date; 2) Protect utility ratepayers against stranded costs; 3) Protect ratepayers against the risk of future unspecified cost increases resulting from increases in the cost of the generation unit compliance with the State Water Resources Control Board once-through cooling policy. For a utility to recover such cost increases from ratepayers, it must obtain approval from the Commission; 4) Are consistent with a need authorization from the System Track of the Long-Term Procurement Plan proceeding; and 5) Are consistent with other procurement rules, including this decision's requirement to file either a Tier 3 Advice Letter or an application.

d. Any such advice letter or application must show compliance with all relevant State Water Resources Control Board policies and regulations, and show how the contract provides or facilitates cost-effective and reliable service.

4. Southern California Edison's proposal for a new proceeding to address a new generation auction mechanism is not approved.

5. Utility-owned generation shall not bid into utility-run requests for offers for generation.

6. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company's utility-owned generation shall be procured only after a corresponding utility request for offers has failed.

7. Applications by Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company for utility-owned generation shall be evaluated using criteria comparable to those used to evaluated independently-owned generation.

8. a. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) are authorized to procure greenhouse gas allowances, allowance futures and forwards, and offsets and offset forwards within separately calculated Direct Compliance Obligation Purchase Limits and Financial Exposure Purchase Limits, as set forth in Appendix 1.

b. PG&E, SCE, and SDG&E may only procure offsets certified by the California Air Resources Board.

c. PG&E, SCE, and SDG&E may purchase no more than 8% of their compliance requirement in the form of offsets.

d. PG&E, SCE, and SDG&E can only purchase offsets if the seller contractually assumes the risk of invalidation.

e. PG&E, SCE, and SDG&E may procure allowances from the California Air Resources Board.

f. PG&E, SCE, and SDG&E may procure allowances via forward contracts, and should apply their standard procurement credit and collateral requirements to these transactions, and may also impose additional credit and collateral requirements as appropriate.

g. If PG&E, SCE, and SDG&E wish to procure authorized compliance instruments via bilateral transactions (including brokers), PG&E, SCE, and SDG&E must utilize a competitive request for offer process, consult with their procurement review group, apply their approved procurement credit and collateral requirements, and apply the applicable affiliate transaction rules.

h. PG&E, SCE, and SDG&E may procure greenhouse gas compliance instruments on Commission-approved exchanges. Prior to purchasing greenhouse gas compliance instruments on an exchange not previously approved by the Commission for power procurement, PG&E, SCE, and SDG&E must submit a one-time Tier 2 advice letter detailing: 1) what exchange they are seeking to use; 2) the liquidity and transparency of the exchange, specifically for California greenhouse gas compliance instruments, including an explanation of how the Commission can be assured that the price of products procured on the exchange is reasonable; and 3) the regulatory authority or authorities the exchange is subject to.

i. PG&E, SCE, and SDG&E may resell greenhouse gas compliance instruments, but should report any such sales to their procurement review group.

9. When Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) update their long term procurement plans in conformance with this decision, they should provide an estimated forecast of the amount of greenhouse gas compliance instruments (in metric tons carbon dioxide equivalents) that correspond with these maximum procurement levels, based upon their current expected range of emissions compliance obligations. The utilities may update their greenhouse gas compliance forecasts as necessary via a Tier 2 advice letter. Forecast updates and corresponding revisions to the procurement limits, along with all greenhouse gas compliance instrument transactions, shall be reported at

each of the quarterly procurement review group meetings and quarterly compliance reports of PG&E, SCE, and SDG&E.

10. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company costs incurred for the greenhouse gas compliance instrument transactions should be included in each utility's Energy Resource Recovery Account filing for cost recovery.

11. The utilities are directed to renegotiate contracts with independent generators that do not currently address the allocation of Assembly Bill 32 greenhouse gas compliance costs so that they reasonably address those costs.

12. The proposal to adopt an independently enforceable procurement rulebook is not approved.

13. The staff audit reports of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company quarterly compliance reports shall be made public.

14. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company procurement review group meeting summaries shall be distributed on the earlier of a) 14 days after the procurement review group meeting, or b) 48 hours before the next regularly scheduled procurement review group meeting.

15. Public versions of independent evaluator reports shall be identical to the corresponding confidential versions, except for the visible redaction of confidential material.

16. Other proposed procurement rule changes relating to independent evaluators are not adopted at this time.

17. This proceeding is closed.

This order is effective immediately.

Dated April 19, 2012, at San Francisco, California.

MICHAEL R. PEEVEY
President
TIMOTHY ALAN SIMON
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
MARK J. FERRON
Commissioners

APPENDIX 1

1.) Direct Compliance Obligation Purchase Limit

Below is the formula for determining the purchase limit on the purchase of compliance instruments used to fulfill a utility's "direct compliance obligation", defined as the tons of emissions for which the utility has an obligation to retire allowances on its own behalf as a regulated entity under the cap and trade regime, and/or is otherwise obligated to procure instruments on behalf of a third party that is a regulated entity under the cap & trade regime (i.e., certain contractual arrangements where the IOU is contractually responsible for procuring allowances on a third party's behalf, or could elect to assume that responsibility). The number that results from this calculation would set the maximum amount of compliance instruments the IOU would be allowed to purchase in the current year. We define "purchase" as taking title of the instrument when it is delivered. Note that under this framework, the IOUs would not be allowed to purchase allowances or offsets with vintages more than 3 years from the current year.

LCY = A + 100% * FDCY + 60% * FDCY + 1 +40% * FDCY + 2 + 20% * FDCY + 3

Where:

"L" is the maximum number of GHG compliance instruments an IOU can purchase for purposes of meeting their direct compliance obligation.

"A" is the utility's net remaining compliance obligation to date", calculated as the sum of the actual emissions for which the utility is responsible for retiring allowances (or purchasing on behalf of a third party) up to the Current Year, minus the total allowances or offsets the utility has purchased up to the Current Year that could be retired against those obligations. This term in the calculation ensures the IOUs are always able to buy sufficient allowance to cover any prior years' shortfalls, given that actual emissions may end up being less than forecast and/or prior decisions about how much procurement to do.

"FD" is the utility's forecasted compliance obligation", the projected amount of emissions for which the utility is responsible for retiring allowances, or responsible for purchasing on behalf of a third party, calculated using an implied market heat rate (IMHR) that is two-standard deviations above the expected IMHR consistent with the approach described by PG&E.

"CY" is the current year, i.e., the year in which the utility is transacting in the market.

Note that should this equation result in a negative number in a given year, the utility's Direct Compliance Obligation Purchase Limit for that year should be set at zero.

2.) Financial Exposure Purchase Limit

Below is the formula that sets the specific limit on the amount of GHG compliance instruments the IOUs can purchase to hedge their financial exposure to greenhouse gas costs under the cap & trade regime. As with the formula above, this is a purchase limit, meaning the number that emerges from this calculation would set the maximum amount of GHG compliance instruments the IOUs would be allowed to purchase in the current year for purposes of hedging their financial exposure. As above, we define "purchase" as taking title of the instrument when it is delivered. Also as above, under this framework, the IOUs would not be allowed to purchase allowances or offsets for hedging purposes with vintages more than 3 years from the current year.

FLCY = 20% * FECY + 10% * FECY+1 + 5% * FECY+2 + 2.5% * FECY+3 – B

Where:

"FL" is the maximum number of GHG compliance instruments that a utility can purchase for purposes of hedging their financial exposure to GHG costs.

"FE" is an estimate of the utility's financial exposure to GHG costs that will, or are anticipated to be, embedded in the price of energy, calculated based on the tons of CO2 for which a given IOU believes it will bear the costs through an embedded cost of carbon as reflected in energy prices. This amount does not include the costs the IOUs anticipate incurring as a result of their direct compliance obligation as "direct compliance obligation" is defined above.

"CY" is the current year, i.e., the year in which the utility is transacting in the market.

"B" is the utility's net purchases of GHG compliance instruments to date for hedging purposes, calculated as the total purchases of GHG compliance instruments for purposes of hedging an IOU's Financial Exposure up to the Current Year minus those GHG compliance instruments sold up to the Current Year. This term helps ensure that if the IOUs have hedged a lot in prior years and those hedges didn't pay out (e.g. the price they saw in the market for carbon stayed below what they paid for a compliance instrument and so they didn't sell the instrument) that gets factored into the amount of additional hedging they are allowed to undertake.

Should this equation result in a negative number in a given year, the utility's Financial Exposure Purchase Limit for that year will be set at zero.

(END OF APPENDIX 1)