ATTACHMENT A
Questions for August 22 Workshop on the RPS Mid-Course Review

California's RPS program was established to help diversify the state's electricity system and reduce its growing dependence on natural gas by increasing the percentage of renewables in the state's electricity mix to 20 percent by 2010. The state's "loading order," a keystone of the joint agencies' Energy Action Plan, requires that increases in load be addressed first through efficiency and demand response, then with renewable and distributed generation, and finally, to the extent these strategies do not fully meet energy and capacity needs, with clean and efficient fossil fuel generation. Consistent with the loading order, the CPUC adopted the "rebuttable presumption" that renewables should be procured before other sources of electricity in all source long term procurement (CPUC Decision 04-12-048).

Although California's investor-owned utilities have begun to contract for additional RPS-eligible generation, increased efforts will be needed to meet the 20 percent by 2010 goal. At the July 6, 2006, workshop:

- PG&E reported that eligible renewables currently account for about 12 percent of its retail sales. PG&E signed contracts to increase its renewables portfolio by 2.3 percent as a result of its 2004 solicitation, and plans to add another 2 percent to 4 percent from its 2005 solicitation. PG&E expects to have a total of 16 percent to 18 percent eligible renewables under contract by the end of its most current RPS procurement cycle.

- SDG&E reported having less than 1 percent renewables in 2001 and increasing its deliveries of renewable energy to 5.25 percent in 2005. SDG&E expects that 6.5 percent of its deliveries will be from eligible renewable energy in 2006 and has contracts in place for 13 percent by 2010. SDG&E stated that, "We fully expect to be at 20 percent by 2010."

- In 2005, SCE stated that it "…purchased or produced nearly 13,000 gigawatt-hours [GWh] of renewable power, approximately 17.2 percent of its bundled retail sales." SCE has contracted for RPS eligible renewables expected to yield 4,000 GWh to 6,000 GWh of renewable energy as a result of its 2004 and 2005 RPS solicitations, and "is working very hard to achieve 20 percent renewables by 2010."

At the July 6, 2006, workshop, participants discussed ways to simplify and streamline the RPS structure. The workshop scope invited participants to explore both regulatory and statutory solutions to meet California's renewable energy goals, including:

- Increasing transparency
- Ensuring that renewable procurement occurs quickly and efficiently
- Addressing transmission and integration issues
- Applying RPS targets consistently to all load-serving entities
- Streamlining accounting for RPS compliance
- Addressing jurisdictional issues and financing

The purpose of this workshop is to follow up on the topics listed below:

- Given the magnitude of uncertainty in natural gas price forecasts, can the market price referent / time of delivery (MPR/TOD) methodology be simplified and more transparent, consistent with similar market estimates used for energy efficiency and for non-renewable procurement processes?

- Reflecting the investor-owned utilities' high level of commitment to achieve 20 percent by 2010, efforts to keep contract failure to a minimum, and the inherent uncertainties of new power plant development, how can the investor-owned utilities, developers, and others work to make sure milestones are met and contracts result in on-line power plants?

- Given the predominant support at the July 6, 2006, workshop to retain the structure of the RPS solicitations through 2010, can the bilateral contracting process be streamlined to ramp up the pace of renewables development consistent with the longer term goal of 33 percent by 2020?

- In support of the 33 percent by 2020 goal, how can the transmission ranking cost reports (TRCR) used in evaluating bids in competitive RPS solicitations, the California Independent System Operator (CA ISO) interconnection queue, and CA ISO cost allocation process be revised to encourage the most cost-effective timing and scale for infrastructure and project development in areas known to have large-scale potential for renewable energy?

Moving toward Less Complex, More Transparent MPR Time of Delivery (TOD) Factors

California's investor-owned utilities use confidential methods and forecasts to develop TOD factors to evaluate RPS bids. The CPUC sought to compare the TOD factors to publicly available benchmarks, but concluded that that no such benchmark has been "sufficiently developed, documented, or explained to be explicitly endorsed or adopted" (Decision 06-05-031, May 25, 2006). For additional background information, please refer to Attachment B, the consultant report, *A Summary and Comparison of the Time of Delivery Factors Developed by the California Investor Owned Utilities for use in Renewable Portfolio Standard Solicitations*. To better understand this issue and develop recommendations for improvement, the Energy Commission seeks input on the following questions:

1. Do current TOD practices dissuade potential bidders or add unnecessary complexity to the bid process?
2. How big of an impact do TOD factors have on RPS bid evaluations?
3. How/why are TOD factors in RPS solicitations different from the following: time dependent valuation (TDV) used in energy efficiency, methods used to calculate the short-run avoided cost (SRAC) for qualifying facilities, and bid evaluation in all-source procurement?
4. Why are the assumptions, methodology, and calculations used in developing TOD factors not available in the public domain?
5. What modifications should be made to make TOD factors more easily benchmarked and ensure TOD factors help the state achieve 20 percent renewables by 2010?

Minimizing Contract Failure

Investor-owned utility RPS incremental procurement targets currently reflect only the minimum required under the statute (1 percent per year) rather than the amount needed to reach full compliance by 2010, including procuring an adequate margin of safety to compensate for contracts that may not come to fruition. A 2006 consultant report discussed at the July 6 workshop indicates that a minimum of 30 percent contract failure should perhaps be expected, based on a survey of 25 North American electric utilities' renewable procurement efforts that resulted in contracts for 21,500 MW.[1] Since failed contracts and delayed projects are common in renewable development, utilities, developers, and state agencies need to work together to keep contracts on track. To ensure that renewable procurement is sufficient to meet RPS goals on time, the Energy Commission seeks input on the following:

6. Lack of close coordination between transmission and project development, unfamiliarity with detailed permitting processes and incomplete communication could result in projects not coming on-line by 2010. What steps are utilities taking to minimize contract failure and delay?

7. At the July 6 workshop, participants suggested that developers may need support from the state, particularly in obtaining permits and complying with regulations, to keep milestones on schedule. What type of support could help developers and utilities prevent delays and contract failure?

Streamlining Bilateral Contracts with the 33 Percent Goal in Mind

The Energy Commission believes that it is imperative to implement the state's 20 percent by 2010 while keeping the 33 percent goal in mind. The 33 percent goal is important to maintain momentum for continued renewable energy development, to expand investment and innovation in technology, and to reduce renewable energy costs.

Although the investor-owned utilities are making progress toward meeting their 2010 RPS goals through the existing contracting process, the Energy Commission seeks to catalyze bold changes in the pace of renewable energy procurement within the current RPS structure. Impressed by the examples set in Texas and Europe, the Commissioners request comment on the following questions:

8. European countries have used feed-in tariffs to take the lead in renewable energy development. Can bilateral contracts be streamlined to achieve similar growth in renewable energy development for California?

9. Should the CPUC require investor-owned utilities to buy any renewable energy offered at or below the MPR?

Addressing Transmission Infrastructure, Process, and Cost Allocation

Participants in the July 6, 2006, workshop identified transmission issues as the most significant barrier to achieving the 20 percent by 2010 goal. Recent CPUC and CA ISO activities addressing renewables transmission issues include:

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[1] *Building a Margin of Safety into Renewable Energy Procurements: A Review of Experience with Contract Failure,* CEC-300-2006-004, January 2006.

a. In September 2005 the CPUC opened an investigation (I. 05-09-005) to address barriers to development of transmission infrastructure needed to meet the California RPS targets.
b. On June 15, 2006, the CPUC issued a decision which provides the utilities with "backstop" transmission cost recovery for RPS-related projects in accord with the provisions of Public Utilities Code 399.25.
c. In July 2006, the CPUC's Executive Director issued a statement establishing transmission project review streamlining directives. It is available at http://www.cpuc.ca.gov/static/energy/environment/index.htm.
d. At its June 14, 2006 board meeting, the CAISO announced a renewable energy transmission initiative. Among other things, the CAISO proposed to develop new evaluation and cost recovery criteria for transmission investments needed to access renewable resources that are not considered network or generation interconnection facilities.
e. The CAISO is currently assessing the need for transmission facilities in Southern California, including the Tehachapi region, San Diego-Imperial Counties, and the proposed Lake Elsinore Advanced Pumped Storage project. The CAISO Board approved the San Diego-Imperial "Sunpath" project on August 3 and CAISO staff plan to have recommendations to the CAISO's Board of Directors in fall 2006 for the other two projects.
f. On July 13, 2006 in I.05-09-005, Commissioner Grueneich issued an Assigned Commissioner's Ruling (ACR) requesting comments on whether parties still believe that it is necessary for the Commission to update the TRCR methodology and if so:
    (1) How this might be best accomplished in an expedited fashion;
    (2) Whether TRCR reform is necessary to accommodate the implementation of locational marginal pricing (LMP);
    (3) Whether the desire for TRCR reform is related to particular location-specific concerns;
    (4) Whether parties believe TRCRs are an adequate proxy for projecting future transmission upgrades;
    (5) The impact of increased remarketing and congestion costs associated with increased delivery flexibility; and
    (6) The desirability and feasibility of calculating project-related transmission costs on a net basis by considering system-wide effects rather than using a gross cost basis focusing only on one project at a time.
g. The July 13, 2006 ACR also
    (1) Requested parties to comment on "whether it is possible or appropriate to develop guiding principles to evaluate the transmission adequacy of contracted and proposed RPS projects";
    (2) Announced appointment of a Tehachapi project manager to coordinate the multiple stakeholders and the transmission and wind resource development processes;
    (3) Addressed the recommendations of the Tehachapi Collaborative Study Group; and
    (4) Ordered the IOUs to file updated status reports regarding transmission development and hurdles, for contracted RPS projects and also prospectively, to be coordinated with RPS project development status reports now being filed in R.06-05-027.

The Federal Energy Regulatory Commission (FERC) has approved alternate regional interconnection queue methods for New England Power Pool, Southwest Power Pool, and the Midwest ISO, although aspects of the latter two are not yet finalized. In the Southwest Power Pool, for example, the FERC has approved a tariff to combine all interconnection requests from a four-month open season into a single aggregate transmission service study.

The CA ISO, IOUs, CPUC and project developers have been exploring the potential for “early” or “temporary” generator interconnections ahead of the build-out of bulk transmission to serve expanding renewable generation.

Building on discussion of the TRCR at the July 6 workshop and in support of the work in the CPUC’s renewables transmission proceeding on this topic, the IEPR Committee seeks further clarification and suggestions for improving the TRCR.

10. Recognizing that TRCRs are intended to inform bidders of least costly interconnection points, do/should TRCRs take into account infrastructure needed to meet 20 percent by 2010 and 33 percent by 2020 rather than incremental changes to the current grid?

11. Does the TRCR reflect only on-line power plants or does it include projects in the CA ISO interconnection queue? If it includes queued projects, are they reflected by queue position or on-line date in allocating costs for network improvement to already congested paths (e.g. Path 15)?

12. How would the TRCR change if the CA ISO tariff were changed to use an aggregated approach to transmission interconnection cost allocation similar to that approved for Southwest Power Pool? If TRCRs use standard off-the-shelf unit cost guides thought to be largely inaccurate (accuracy of +/- 40 percent), should they be used to exclude bids from further evaluation?

13. What aspects of TRCRs used in previous or ongoing solicitations are most likely to result in lost opportunities, and what changes could prevent such losses?

14. During RPS bid evaluation, are any network upgrade costs attributed to RPS projects? Are any treated as costs paid by all transmission users?

15. Given that transmission development is needed to meet the state’s RPS goals, how can the TRCRs be revised to avoid discouraging competitively priced projects in remote but renewable-rich areas? How can TRCRs be revised to encourage competitively priced projects that can provide VAR support and other transmission system benefits?