

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Investigation to facilitate proactive development of transmission infrastructure to access renewable energy resources for California.

Investigation 05-09-005
(Filed September 8, 2005)

**COMMENTS OF THE CALIFORNIA WIND ENERGY ASSOCIATION
ON ASSIGNED COMMISSIONER'S RULING ON NEXT STEPS
IN FACILITATING CONSTRUCTION OF TRANSMISSION FACILITIES TO
ADVANCE CALIFORNIA'S RENEWABLE PORTFOLIO STANDARD GOALS**

Nancy Rader
Executive Director
California Wind Energy Association
2560 Ninth Street, #213-A
Berkeley, CA 94710
Telephone: 510-845-5077
nrader@calwea.org

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Order Instituting Investigation to facilitate proactive development of transmission infrastructure to access renewable energy resources for California.

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**Comments of the California Wind Energy Association
on Assigned Commissioner's Ruling on Next Steps
In Facilitating Construction of Transmission Facilities to Advance California's
Renewable Portfolio Standard Goals**

Pursuant to the July 13, 2006, Assigned Commissioner's Ruling ("ACR") by Commissioner Grueneich, and the extension of time granted by ALJ Halligan on August 3, 2006, the California Wind Energy Association ("CalWEA") responds herein to the questions raised in the ACR.

In summary, our comments are as follows:

- **TRCR Methodology.** The Commission's policies on power delivery points partially address problems with the TRCRs by requiring the utilities not to apply TRCR costs to out-of-service-territory bids if it is less expensive to remarket the power near where it is delivered. However, the utilities should be required to demonstrate how remarketing costs are evaluated and, more generally, to explain how the TRCRs have affected bidding overall. In addition, because TRCR estimates of upgrade costs will still be relevant for some projects, it is essential that those costs be adjusted downward to account for the associated system benefits. CalWEA and others have put forward various proposals to accomplish this in the past without success, but would be glad to revisit the issue

- **Developing Resource-Indifferent Guiding Principles To Evaluate The Transmission Adequacy Of Contracted And Proposed RPS Projects.** Rules in this area are not necessary. Determining project viability and timelines is the utilities' responsibility, and is not an area that calls out for additional rulemaking. The utilities are motivated by financial incentives, so the imposition of penalties when RPS goals are not met will go a long way toward making them faster, smarter and more reasonable. This extends to the issue of facilitating temporary interconnections; while the utilities should be encouraged to join the CAISO in enabling temporary interconnections whenever possible, the imposition of noncompliance penalties will go along way toward fostering a can-do attitude.

- **The CPUC should encourage the CAISO to better facilitate the interconnection process** by batching multiple projects into one study process, which would enable a single study on the total generation capacity expected in an area, so that the status of any single project does not upset the process for other projects.
- **Generators need to be provided with certainty about their pro-rata share of interconnection costs** before the generator is required to make a binding price bid. The Commission should invite proposals from the utilities and convene a workshop.
- **Continued attention to the CPCN streamlining and transmission construction process is needed**, as the ACR recognizes. The CPUC should focus on processing CPCN applications within 12 months, and find ways to reduce the time between CPCN approval and the start of construction. Finally, the Commission should anticipate making a need determination for Tehachapi Phases 2 and 3 in early 2007.
- **Coordination of RPS procurement and transmission planning is needed** to ensure that transmission capacity being planned for renewables projects ends up being allocated to those projects in the queuing process. The CPUC should instruct the utilities to seek, in the 2006 and/or 2007 round of solicitations, PPAs for deliveries in the 2008-2010 timeframe to fulfill their 2010 RPS goals, linking on-line dates to actual transmission construction.

I. Does The TRCR Methodology Need To Be Reformed?

The ACR asked whether the TRCR methodology needs to be reformed and, if so, how this might be accomplished. Our thoughts on this subject are as follows.

A. The Commission's policy on power delivery points partially addresses problems associated with the TRCRs

As discussed in the next subsection, a great failing of the Commission's policies relating to the TRCRs has been allowing the utilities to ignore the benefits associated with network upgrades that are necessary to deliver bidders' power to the purchasing utility. This problem was in large part addressed – indirectly -- by the Commission's policy in Decision 05-07-039 (July 21, 2005), which enables RPS bidders to deliver their power anywhere on the California Independent System Operator's (CAISO) grid, with these bids evaluated on the basis of their ability to avoid the need for transmission

upgrades. Decision 06-05-039 (May 25, 2006), at page 15, extended this policy to deliveries anywhere in California, based on a proposal by PG&E. Finally, in response to CalWEA's June 13, 2006, protest to PG&E's June 9 RPS Protocol, PG&E agreed not to perform an initial evaluation of bids using its TRCR as though all bidders are required to deliver power to PG&E's load centers. Instead, it agreed not to apply TRCR costs to out-of-service-territory bids if it is less expensive to remarket the power near where it is delivered.

This policy (assuming it is implemented fairly by all three utilities) effectively eliminates the problem of the TRCRs' failure to net out system benefits, at least for inter-zonal transfers including the one of greatest present concern to CalWEA: sales from Tehachapi to PG&E.¹ However, as discussed below, it would still be desirable to know how the utilities go about evaluating the remarketing costs to ensure that it is being done fairly, and it is necessary to consider network benefits in the TRCRs for some cases.

In response to the ACR's question – "is TRCR reform necessary to accommodate the implementation of locational marginal pricing (LMP)?" – LMP should make remarketing costs more straightforward, since there will be a price at every node reflecting congestion. But LMP is not relevant to the TRCRs, because the TRCRs are aimed at eliminating congestion through the physical addition of transmission capacity, rather than efficiently responding to congestion.

B. The utilities should be required to demonstrate how remarketing costs are evaluated, and, more generally, to explain how the TRCRs are affecting procurement overall

Although the problem with the TRCRs has been partially addressed conceptually, per the above discussion, the Commission and the parties should have some assurance that the remarketing costs are being calculated fairly in practice. The Commission should direct the utilities to provide an explanation, including detailed hypothetical examples that do not involve confidential data, of how they evaluate the remarketing costs of out-

¹ Note that the following statement in the ACR may therefore be irrelevant: "However, limited renewable potential in the PG&E service territory might lead to a need for out-of-area imports requiring significant transmission upgrades." While the upgrades may be needed for reliability or efficiency reasons, they are not required to meet the RPS goals as long as a sufficient amount of renewable generation can get to California load somewhere.

of-territory bids. The utilities should also be asked to identify any related effects on bid evaluation, such as whether and how it affects capacity value. This information should be subject to comment by the parties, and a ruling by the Commission if necessary.

More generally, parties who are not participants in the utilities' Procurement Review Groups are in the dark as to exactly how transmission bid adders have been applied to bids, what bid-specific adjustments were made, and how the bid adders affected the results. Since there is no transparency in the process, and since the CPUC never conducted the "lessons learned" workshop that was scheduled for April 2005,² the market participants have no clear understanding of how the transmission bid adders are being applied in practice. We urge the Commission also to require the utilities to provide detailed information about how the TRCRs are affecting the bid evaluations, and to convene a "lessons learned" workshop on this and other issues. One way to do this without violating confidentiality rules would be for the utilities and their PRGs to jointly prepare a memo to parties in this proceeding which summarizes the use of adders in a particular bid evaluation process, including specific (generic and non-confidential) examples.

C. Reflecting network benefits associated with upgrades in TRCRs will still be necessary in some cases

In some cases, the costs of remarketing may exceed the TRCR cost that will otherwise be applied, or remarketing may not be possible because upgrades are needed to get the output to some load (i.e., there is no market without the upgrade). The utilities should be asked to report on the general project locations where this is the case, or likely to be the case. In these instances, it will be necessary to adjust upgrade costs by the associated system benefits.

The ACR raises as an issue "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" and references D.06-05-039 at 17-19. That decision, at p. 19, suggests

² See the December 16, 2004, Assigned Commissioner's Ruling by Commissioner Peevey.

One potential improvement is for IOUs to subtract transmission costs related to a non-RPS scenario from those related to an RPS scenario on a system-wide basis to determine the net costs that should be used for the LCBF analysis. This might be done in large increments of RPS versus non-RPS facilities. The result might be that IOUs and their ratepayers are responsible for the cost of the “backbone” transmission system, with RPS generators responsible in the LCBF ranking analysis only for their reasonable costs of interconnection to the grid (e.g., generation tie lines).

If implemented, this suggestion would effectively eliminate the entire bid adder, which reflects only indirect (network) costs and therefore by definition excludes direct-assignment (non-network) interconnection costs which are direct costs. CalWEA and others have put forward various iterations of this basic approach in the past without success.³ We would, however, be glad to revisit the issue, particularly when the CAISO and the CPUC agree upon a methodology to assess the economic benefits of transmission projects. As we have long argued, counting the costs of transmission upgrades without recognizing the associated system benefits produces inefficient and discriminatory bidding results.

In particular, where system benefits have been quantified, as will be the case very soon with the Tehachapi upgrade, the Commission should order the utilities to adjust the associated bid adder to reflect the net costs of the upgrade.

³ In D.04-06-013, for example, the Commission rejected several proposals that were put forward for accounting for network benefits. The Commission rejected CalWEA’s alternate proposals that (a) the Commission make a blanket determination that benefits of network upgrades at least equal their costs; (b) that hearings be held to identify network benefits as offsets to transmission upgrade costs; or (c) that a rebuttable presumption be made that upgrades operating at 230 kV and above will benefit the network and that the net cost of transmission adders for such upgrades would be zero, and, for lower voltage upgrades, that the transmission owner be required to estimate savings due to lower line losses and also be required to estimate the increase in transfer capability across existing constrained interfaces. The Commission likewise rejected a proposal by TURN (that the benefits of increased network transfer capacity be valued at one half the pro rata cost of the incremental capacity) and a proposal by CEERT (that developers be provided the option to have their bid ranked with and without their estimate of network benefits, and if acceptance or rejection of the bid depends on whether system benefits are considered, the utility would determine whether to consider system benefits, provide documentation to the bidder, the Commission, and the Procurement Review Group, at which point the issue would be resolved in the normal review process and/or a generic dispute resolution process).

II. Is It Possible Or Appropriate To Develop Resource-Indifferent Guiding Principles To Evaluate The Transmission Adequacy Of Contracted And Proposed RPS Projects?

A. No, rules in this area are not necessary

We assume that the concern associated with this question, posed in the ACR, is the fact that many of the resources contracted for by the utilities cannot come on line until transmission upgrades are completed, thus delaying delivery. This is not in and of itself a problem; a problem exists only if the utilities have not procured sufficient energy to meet their annual RPS targets in each year, in view of transmission construction timelines that they should be able to anticipate. Determining project viability and timelines is their responsibility, and is not an area that calls out for additional rulemaking.

However, the utilities have asked for – and received – a lot of flexibility in how they procure resources (e.g., there is almost no standardization of contract terms, little transparency in the LCBF process, and wide latitude in the procurement process). It is essential that the utilities therefore be held accountable for meeting the RPS targets, which may be due in part to onerous terms, particularly excessive credit requirements, as well as insufficient due diligence in weeding out projects that have little chance of success. The utilities are motivated by financial incentives, so the imposition of penalties when goals are not met will go a long way toward making them faster, smarter and reasonable.

B. The utilities and the CAISO should be encouraged to enable earlier, temporary interconnections

Where long lead-times are expected with transmission upgrades, such as in Tehachapi, the CAISO and the utilities should be encouraged to be proactive in enabling temporary interconnections that will allow for earlier project development. Recently, the CAISO has demonstrated such proactiveness; the CPUC should encourage the utilities to work with the CAISO in finding solutions to speed project interconnections. Creating financial incentives through the imposition of noncompliance penalties could also help in this area.

C. The CPUC should work with the CAISO to better facilitate the interconnection process

The queuing process does not allow for the batching of multiple projects' in the same area for application processing purposes, which needlessly adds costs and delay. For example, when a project drops out of the queue, the study process must begin anew, setting timelines back by as much as three months or more. This is a significant problem at present in Tehachapi. Batching multiple projects into one study process would enable a single study on the total generation capacity expected in an area, so that the status of any single project would not upset the process for other projects. The CAISO should be encouraged to better manage these issues for current as well as future applications.

III. Additional Issues That Should Be Addressed In 2006 Or Early 2007

A. Generators need certainty regarding their pro-rata share of interconnection costs that will accommodate multiple generators

In the Tehachapi Collaborative Study Group (TCSG) process, all parties agreed that it is important and necessary to provide generators with certainty as to the share of interconnection costs they will be responsible for when the utility builds non-network upgrades that will accommodate multiple generators. As stated in the March 2006 TCSG report (at p. 94-95):

While this chapter has focused on providing cost recovery assurance for utilities, the TCSG points out that an essential purpose of this assurance is also to provide reasonable regulatory certainty to generators as to what costs they will be responsible for before committing to a fixed-price bid and securing financing for a project. Therefore, the TCSG further recommends the following:

The Commission should provide generators with reasonable certainty concerning the transmission costs they will be responsible for before the generator is required to make a binding price bid. The CPUC should require the utility to develop an estimate of the pro-rated facilities charge it will assess to generators interconnecting to the authorized facilities before construction of the transmission facilities commences. [FN 40 That charge will be a component of the standard interconnection agreement that the parties file at FERC.] Various solutions may be possible. For example: any costs exceeding this amount could be recoverable through the ratepayer backstop [FN 41 Potentially charging ratepayers for a share of costs may be particularly appropriate when the upgrade provides system benefits (though short of what is required to achieve "network" status) or when

the upgrade is expected eventually to become part of a larger network configuration.] or, the generator could be allowed to adjust its PPA according to actual costs.

CalWEA urged the Commission to address this issue in its P.U.C. 399.25 decision, which was not done. It is important that the Commission now do so, because it affects projects that are now, or soon will be, in the bidding process. It would probably be most efficient to invite proposals from the utilities on the subject, and then convene a workshop to discuss them. Based on TCSG discussions, we believe that all parties agree in concept that this problem needs to be addressed; the details of how to do so are complicated, however. Ultimately, the issue should be reduced to a standard contract term that is included in all contracts involving this issue.

B. Continued attention to the CPCN streamlining, and transmission construction, process is needed

The ACR notes that the Commission has addressed the issue of streamlining the CPCN approval process, and has hired a Tehachapi Project Manager to establish milestones in the process, which we applaud. While we will be participating in the upcoming workshop on these topics, we want to underscore here the importance of completing the Tehachapi CPCN application process within 12 months, as required by the FEREC. In addition, to enable achievement of RPS goals by 2010, it will be important to reduce the time between the approval of the CPCNs and the start of construction. One way to achieve this will be to encourage the utilities to pre-plan and pre-order the major components.

Finally, the Commission should anticipate making a need determination for Phases 2 and 3 in early 2007. The ACR states (p. 9-10) that it would be premature to make a finding of need for Tehachapi Phases 2 and 3 at this time, for several reasons. We do not disagree with that reasoning. However, we note that the TCSG's Second Report recommended that the Commission make such a finding "before or early in the CPCN approval process" (TCSG Second Report at p. 113). Therefore, we encourage the Commission to plan to make such a finding in the first quarter of 2007, given SCE's possible filing of the CPCNs in March 2007.

C. Coordination of RPS procurement and transmission planning

The ACR recounted again the need to coordinate RPS procurement with transmission planning (e.g., ACR at 5 and 7). And yet, the ACR states, in Footnote 2 (p. 3), that, because access to transmission facilities is subject to FERC-approved open access rules which provide grid access on a nondiscriminatory basis based on competitive bids”, “the issue of guaranteeing renewable access to transmission built for them appears to be resolved.” We disagree, as we have explained in earlier filings. If renewable projects are not in the queue, the transmission capacity that is being planned for renewables could end up being allocated to non-renewable projects inside or outside of the targeted renewable resource area. The CPUC has the ability to affect this issue by instructing the utilities to seek, in the 2006 and/or 2007 round of solicitations, PPAs for deliveries in the 2008-2010 timeframe to fulfill their 2010 RPS goals, linking on-line dates to actual transmission construction. The contracts would need to address the uncertainty in future federal tax benefits. To ensure that the planned transmission capacity will actually be used for renewables, the utilities should seek (collectively) to sign PPAs for the full amount of transmission capacity that is being planned so that queue positions can be taken and capacity reserved.

Thank you for considering these comments. We look forward to hearing the thoughts and ideas of other parties.

Respectfully submitted,

A handwritten signature in black ink that reads "Nancy Rader" followed by a circled "CME" or similar initials.

Nancy Rader
Executive Director
California Wind Energy Association

August 18, 2006

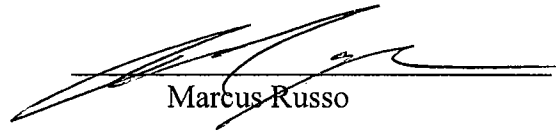
Certificate of Service

I hereby certify that I have this day served a copy of the

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on all known parties to I.05-09-005 by sending a copy via electronic mail and by mailing a properly addressed copy by first-class mail with postage prepaid to each party named in the official service list without an electronic mail address.

Executed on August 18, 2006, at San Francisco, California.



Marcus Russo