

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

Order Instituting Investigation into Implementation of
Assembly Bill 970 Regarding the Identification of Electric
Transmission and Distribution Constraints, Actions to
Resolve Those Constraints, and Related Matters Affecting
the Reliability of Electric Supply.

Investigation 00-11-001
(Filed November 2, 2000)

**COMMENTS OF THE
CALIFORNIA WIND ENERGY ASSOCIATION
ON THE INTERIM OPINION REGARDING
TRANSMISSION COSTS IN RPS PROCUREMENT**

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Pursuant to Rules 77.2 through 77.4 of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, the California Wind Energy Association ("CalWEA") submits these comments on the June 21, 2005, draft Interim Opinion Regarding Transmission Costs In RPS Procurement ("Draft Decision"). The Draft Decision directs the utilities, in preparing their 2005 Transmission Ranking Cost Reports ("TRCRs") to use the methodology adopted in Decision (D.) 04-06-013 for the first Transmission Ranking Cost Reports, except to the extent modified in the present order.

A. Introduction

As was made clear by wind industry participants at the January 20-21, 2005, workshop on the transmission cost methodology, the wind industry is concerned that wind bids may be dealt death by a thousand cuts by the layering on of numerous conservative or unreasonable assumptions in the bid adder methodology -- e.g., loading the costs of generally necessary statewide transmission upgrades onto renewables bids; failing to take any account of the benefits of upgrades and netting those benefits against costs; failing to spread upgrade costs over the full development of resource clusters in promising resource areas; failing to consider the fact that coincident wind generation is less than total nameplate generation, etc.

Moreover, parties who are not participants in the utilities' Procurement Review Groups are in the dark as to exactly how transmission bid adders were 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 has not conducted the "lessons learned" workshop that was scheduled for April, the wind industry has no clear understanding of how the transmission bid adders are being applied in practice. We therefore remain concerned, and, given the complaints voiced at the workshop, are puzzled by the statement in the Draft Decision (at p. 4) that "No party contested the methodology adopted in D.04-06-013 for treating transmission costs during the rank ordering process." We propose, as an initial matter, that this sentence be eliminated from the final decision.

In these comments, we make several modest suggestions that significantly improve the current methodology by removing a number of its inherent biases that have the effect of inflating assumed transmission costs.

B. In View Of FERC's Findings On Antelope Segments 1 And 2, The Commission Should Find That The Network Benefits Of These Segments Are Equal To The Costs

For the reasons set forth below, we urge the Commission to adopt the limited measure of directing Southern California Edison ("Edison") to assume that the network benefits associated with Antelope Segments 1 and 2 are at least equal to the costs of those upgrades.

The Draft Decision (at p. 7) states that "the utilities should consider any identified network benefits as offsets to needed transmission upgrade costs to the extent practicable." What is to be considered "practicable" is, however, unspecified.

In D.04-06-013, 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 adds 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).

The Commission stated, in D.04-06-013 (at p. 16), that "the analytical tools [do not] exist at this time to quantify such benefits. We intend to consider network benefits in future RPS solicitations to the extent feasible. In particular, we expect that the development of a

methodology for assessment of the economic benefits of transmission projects, which is underway in another phase of this proceeding, will be useful in this regard.” But the Commission is still reviewing that methodology – the CAISO’s Transmission Economic Assessment Methodology (“TEAM”) – and the process is moving slowly.

Likewise, the expectation expressed in the Draft Decision (at p.7) that studies by the California Energy Commission’s (CEC) Public Interest Energy Research group “may allow identification and quantification of network benefits of renewable projects and related transmission upgrades” appears to be misplaced. The CEC’s “Strategic Value Analysis” appears not to be immediately useful for the purpose of calculating transmission bid adders for at least two reasons: (1) it does not evaluate the transmission upgrades associated with all renewable resource bids (including extensive development of the Tehachapi wind resource area) because the goal of this project is to identify areas that would require limited or no transmission upgrades, and (2) it does not appear to produce values that could be translated to a \$/kW or a ¢/kWh basis for application to bids.¹

Finally, the Draft Decision would reject CEERT’s proposal that the costs of transmission upgrades not be assigned automatically to RPS projects, which would effectively have recognized the network value of transmission upgrades.

The Commission’s directive that the utilities “should consider any identified network benefits ... to the extent practicable” therefore rings hollow. As we have argued before, counting the costs of transmission upgrades without recognizing the benefits will produce inefficient and discriminatory bidding results. Ignoring the network benefits of transmission improvements as an offset to the transmission costs added to bids (thereby assigning to benefits the arbitrary figure of zero) is a far greater error than imperfectly assessing the benefits.

We urge the Commission to place the quantification of network benefits high on its priority list for resolution in advance of the 2006 RPS solicitations, and to employ independent consultants if necessary to resolve the issue (even imperfectly, as ignoring the

¹ See “Strategic Value Analysis For Integrating Renewable Technologies in Meeting Target Renewable Penetration in Support of the 2005 Integrated Energy Policy Report” (Consultant Report), California Energy Commission, June 2005 (CEC-500-2005-106).

issue is worse than failing to achieve perfection, which is subjective in any case) as we recommended early in this proceeding.²

In the meantime, we urge the Commission to adopt the interim, limited measure of directing Edison to assume that the network benefits associated with Antelope Segments 1 and 2 are at least equal to the costs of those upgrades.³ This measure is reasonable, given that the FERC has now adopted those two segments as network upgrades eligible for “rolled in rate treatment” based on SCE’s characterization that both facilities pass all five of the “Mansfield” tests and the “7-factor test” used by the CAISO.⁴ (It is not necessary for an upgrade to pass each of the Mansfield tests for roll-in treatment to be granted; just one is sufficient.⁵) This characterization was uncontested.⁶ FERC’s decision should be a sufficient basis for the CPUC to rule that the benefits of these facilities can be assumed to outweigh the costs, resulting in a zero bid adder for these upgrades. Such a decision would be consistent with this Commission’s earlier findings that “Section 399.14(a)(2)(B) would allow transmission costs to be considered net of established benefits in the ranking process” (D.04-06-013, Conclusion of Law No. 1), that “particular projects may provide clear benefits to the transmission system” (D.04-06-013, p. 17), and that “We intend to consider network benefits in future RPS solicitations to the extent feasible” (D.04-06-013 at p. 16).

² See “Prehearing Conference Statement of The California Wind Energy Association on the Refinement of the Transmission Cost Methodology Adopted In D.04-06-013” in this docket (September 28, 2004).

³ We put aside here our argument that there is sufficient basis to make a network benefit finding for Segment 3 as well. There is sufficient evidence in the record of the Tehachapi case (which culminated in D.04-06-010) for the CPUC to make this finding, but it has not yet done so. FERC ruled on the basis of SCE’s declaration of there being no network benefits associated with Segment 3.

⁴ See Southern California Edison Company’s Petition for Declaratory Order before the FERC (Docket No. EL05-80), March 23, 2005, at pp. 9-11. SCE states that the facilities would meet all five of the Mansfield tests: Test 1 – the facilities would be part of the looped transmission system; Test 2 -- the energy would flow from Antelope to Pardee but would also flow in the reverse direction depending on the season and the generation on line; Test 3 -- the CAISO would be able to provide service to the Participating Transmission Owners and to other transmission customers over the facilities; Test 4 -- the facilities would provide capability and reliability benefits to the transmission grid and could be relied on for coordinated operation of the grid; Test 5 -- an outage on the facilities would affect the transmission system.

⁵ See 108 FERC ¶61,084 (July 29, 2004) (Northeast Texas Electric Cooperative), *aff’g* 100 FERC ¶63,033 at para. 51 (2002) (Initial Decision). In the *Northeast Texas Electric Cooperative* decision, the FERC reiterated that “the Commission’s policy [is] that costs should be rolled in when *any* degree of integration has been shown” (emphasis added).

⁶ *Southern California Edison Company*, “Order on Petition for Declaratory Order,” Docket No. EL05-80-000, 112 FERC para. 61,014 (July 1, 2005) at para. 38.

C. The Methodology Should Require the Utilities, in Allocating Upgrade Costs, to Take Into Account the Entire Cost and Full Development of a Resource Cluster

The Draft Decision (at p. 11-12) would “not modify for 2005 the previously adopted policy that the entire cost of a transmission upgrade be considered in ranking the projects that would use the upgrade,” despite the stated concern that

allocating the entire cost of a large transmission upgrade to the projects that have bid in response to one year’s procurement solicitation does not take into account that, in some areas, the most cost-effective transmission upgrade may be large enough to accommodate more than one year’s bidders. Considering the entire cost in assessing one year’s bids may make it difficult for such projects to ever win the bid or for the needed transmission upgrade to be built. (D.04-06-013, mimeo. at 35-36.)

The Draft Decision (at p. 12) once again points to the Commission’s directive to the Tehachapi Collaborative Study Group (TCSG) to “examine the use of triggers for the construction of phased transmission upgrades in that region” and that the “record to be developed in A.04-12-007 [the Antelope-Pardee CPCN proceeding] on this issue may assist our consideration of how to treat the cost of Tehachapi upgrades in assessment of RPS bids from that region.”

The Draft Decision fails to distinguish between the trigger to initiate permitting activities and actually construct the upgrade (which is what the TCSG considered) and the trigger for purposes of a bid evaluation to spread the cost of an upgrade across all competitive projects that could use the upgrade. If the Commission sets a high bar on the bid evaluation, it risks never getting to the construction question because bidders may never clear the initial bar.

Two modifications to the Draft Decision are necessary to ensure that the transmission cost adders applied to project bids properly reflect the project’s pro-rata share of associated upgrade costs, including reasonable assumptions that the upgrade will be fully utilized.

1. The methodology should take into account the full development of a resource cluster in some circumstances

In certain circumstances, the methodology should explicitly require the utilities to allocate the cost of a transmission upgrade equally over all of the renewable resources associated with the cluster, on a pro-rata basis, regardless of whether the combined capacity of the bids received equals or exceeds the capacity of the upgrade. A utility should be required to spread costs in this way if there is a reasonable basis for finding that the utility and/or other retail sellers will need the renewables in that cluster by 2010 to meet the 20% RPS goal. The assumption would be reasonable if RFP results show a sufficient number of competitive (but not necessarily winning) bids from the cluster. By “competitive,” we mean that, had the utilities sought to fulfill their 20% obligation in the present RFP, the entire cluster would have been selected due to its competitiveness. If the total capacity of the competitive bids is below the capacity of the upgrade, the Commission still should find that the cluster’s renewables are needed if there is an amount of known resources of equivalent quality – and thus presumably of similar price -- in the area (based on the CEC’s Renewable Resources Development Report and other information) exceeding the capacity of the upgrade. In the case of Tehachapi, the Commission has already made findings sufficient to assume, at least for purposes of the bid adders, that the Phase 1 facilities will be fully utilized.⁷ All three utilities should share sufficient information about the bids they receive so that they have full knowledge about the total amount of capacity that has been bid from within a particular cluster.

2. All of the upgrade costs associated with a cluster should be captured, including the costs associated with generators in the queue

The objective of the transmission cost bid adder should be to compare the total cost (net of benefits) of transmission for one renewable resource cluster to the total costs of other clusters (allocated pro-rata among all resources in the cluster, as described in the preceding

⁷ “The Tehachapi area contains the largest wind resource area in California and, if more fully developed, will meet a significant portion of the goals for renewable energy development in California.” D. 04-06-010, Finding of Fact No. 3. “It is reasonable initially to conclude that the first phase of Tehachapi transmission upgrades are necessary to facilitate achievement of the renewable power goals established in the State’s renewable portfolio standard, required by Public Utilities Code Section 399.14.” D.04-06-010, Finding of Fact 18.

subsection). The result would be that all of the upgrade costs associated with a cluster will be captured, including the costs associated with generators in the queue, which are likely to be the least-cost network upgrades.

The current methodology, however, allows a utility to exclude upgrades already in the queue. (“[W]e do not require (but would allow) the utilities to separately identify in their Transmission Ranking Cost Reports a base case that excludes transmission capacity identified ... for projects in the ISO queue and, thus, included in the base cases in their conceptual transmission studies.” D.04-06-013, p. 29.) This practice can inappropriately inflate the bid adders. Only upon a showing by a utility that the calculation cannot reasonably be performed unless existing upgrades are excluded should the Commission allow the utilities to exclude queue-related upgrades and separately evaluate the bid adder for queued projects.

D. The Commission Should Require the Utilities to Consider Coincident Generation

The Draft Decision states (at p. 10), “At the workshop, parties reported that pending CEC-sponsored wind studies may provide useful information regarding the coincidence of wind generation. Such information may appropriately be reflected in future Transmission Ranking Cost Reports. However, lacking completed studies, we do not modify the Transmission Ranking Cost Report process at this time in this regard.” The Draft Decision would therefore continue to ignore the fact that coincident wind generation is less than total nameplate generation (on the order of 15%). Thus, for example, a transmission upgrade might be assumed to accommodate 200 MW of nameplate wind generation when it could actually be expected to accommodate 230 MW.

Calculating coincident generation does not require “completed studies.” It is a simple matter of dividing the maximum production figure from each wind resource area by the rated power of the respective area. The CEC consultants who conducted the RPS Integration Studies possess the maximum production figures for each wind resource area; based on our discussions with them, they could easily calculate the coincident generation figures if the utilities supply them with the rated power of those areas.⁸ We believe that the coincident

⁸ Personal conversation between Nancy Rader and CEC Consultant Kevin Jackson.

generation figure translates directly into reduced transmission costs per megawatt. Whatever the utilities believe, they ought to take it into account in their TRCRs.

We request, therefore, that the Commission (a) direct PG&E and Edison to supply the CEC with the rated power of the wind projects within their service territories for the purpose of calculating coincident generation figures, and (b) direct all three utilities to take these figures into account in their TRCRs, explaining how they have done so. (Though production data is not available for the San Diego County wind resource area, SDG&E should still be able to presume something less than 100% coincident generation based on the data from the other wind resource areas.)

While this may be a relatively small point – perhaps resulting in increasing the capacity available at each bus by 10-15% -- it is one that is easily corrected. We are concerned that layer upon layer of conservative assumptions are serving to inflate the assumed costs of wind generation. At a minimum, the utilities should not impose hard and fast capacity cut-offs for each transmission upgrade.

E. The Commission Should Provide Parties with Information About How the Transmission Bid Adders Have Been Applied

In order to instill confidence in the bid adder process, and in order to improve the process for the next round of bids, all parties need information about what occurred the first (and soon second) time around. One way to inform the parties 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 the bid evaluation process and provides specific (generic) examples. The Commission should order such a report, ideally prepared with the assistance of a neutral consultant that would be paid for by the utilities.

Respectfully submitted,

 (BR)

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July 11, 2005

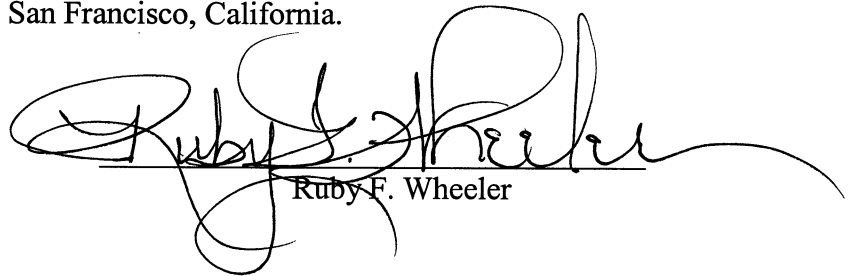
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**COMMENTS OF THE CALIFORNIA WIND ENERGY ASSOCIATION ON THE
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Executed on July 11, 2005, at San Francisco, California.



Ruby F. Wheeler