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)**

PRE-HEARING CONFERENCE STATEMENT OF THE CALIFORNIA WIND ENERGY ASSOCIATION REGARDING TRANSMISSION COSTS FOR RENEWABLE PORTFOLIO STANDARD BIDS

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March 2, 2004

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Pursuant to the February 17, 2004, Administrative Law Judge's Ruling, the California Wind Energy Association ("CalWEA") respectfully submits this Pre-Hearing Conference statement. **Part I** of the statement explains that a factual basis exists for the Commission to assume that network upgrades will produce benefits at least equal to their costs. Should the hearing record support this factual basis, the Commission should adopt that conclusion and eliminate that stage of the bid adder process that involves assigning to each individual bidder the ostensible upgrade cost associated with its bid, on the grounds that the net cost (benefits minus cost) is at least zero. Such a result would not be in disregard of the statute calling for "least cost best fit," but instead would apply the statute accurately by not assigning costs which do not exist. With the elimination of the bid adder relating to transmission upgrades, the remaining focus in this proceeding would be the development of a methodology for establishing generation interconnection ("gen-tie") costs and allocating those costs among bidders. These costs would alter bids directly since all gen-tie costs are to be borne by the bidders.

If the Commission does choose to assess the costs and benefits of upgrades specifically for each bidder, **Part II** comments on the process proposed by Pacific Gas & Electric.

I. The CPUC Should Find That Network Benefits Will At Least Equal Network Costs, Thereby Removing The Question Of Bid Adders For Network Upgrades And Focusing The Inquiry On Inter-Generator Allocation Issues

A. There Is a Persuasive Factual Basis for Determining That Network Benefits Will At Least Equal Network Costs

In this proceeding, the Commission intends to develop a method for determining bid adders for each renewable resource that reflect the costs of transmission network upgrades needed for each renewable resource. One of the major premises underlying the asserted need for bid adders is that ratepayers will incur costs for upgrading the transmission network that are solely and uniquely attributable to specific renewable resources or groups of renewable resources. Following this logic, the Commission would determine that unique upgrade cost and add it on to the bid submitted by each affected renewable resource as a penalty in evaluating the bid from that renewable resource. CalWEA recommends that the Commission find that this process is not necessary, for the reasons discussed below.

1. Gen-tie costs will be directly assigned. There is no dispute that when a generator is interconnected to the grid some of the interconnection costs are uniquely associated with that specific generator. The generator step-up transformer, the associated circuit breaker, disconnect switches, metering, and other switchgear (and possibly a radial transmission line to the nearest network facility) can be used only by that generator. For that reason, these interconnection (or "gen-tie") costs have traditionally been assigned in their entirety to the interconnecting generator. The generator adds those interconnection costs to the costs that the generator seeks to recover when making a bid or selling its power in a bilateral arrangement.

2. Network upgrade costs are different from interconnection costs because they are not unique to a particular interconnecting generator. By their very nature, network upgrade costs are not unique to any particular interconnecting generator. Although they may be necessary in the first instance to interconnecting a particular generator and may be precipitated by that interconnection event, network upgrades produce benefits for other generators, other transmission users and society as a whole. Such benefits are not always precisely quantifiable, and the scope and nature of those benefits often become clear only as they are identified and realized during periods far into the future. For example, network upgrades not only provide a path for the interconnecting generator to reach load; because they are upgrades to the network they also provide an alternative path through which other existing and future generators can reach loads. This alternative path provides a backup or reliability function that benefits all users, not only the newly interconnecting generator. A network upgrade also tends to reduce congestion costs and transmission losses experienced by all users of the upgraded transmission path.

In addition, network facilities provide a springboard for further low-cost transmission upgrades and for the addition of other generators, usually at a lower incremental cost than that associated with the first generator. That is, the incremental cost of network upgrades is almost always lower when those upgrades can make use of pre-existing rights-of-way, circuits, substations and structures. For example, when network facilities are extended into a remote area such as Tehachapi, they provide infrastructure for further generation developments and for regional interconnections between northern and southern California, between California and Nevada, and between the Pacific Southwest and the Pacific Northwest. New generation can often serve remote loads presently served by stressed transmission systems (as is the case in Tehachapi) and actually improve local reliability. The "N minus one (N-1)" criterion[1] of NERC and WECC can be met at a lower cost if the transmission owner can upgrade pre-existing facilities in lieu of developing an entirely new network. Such network benefits are produced when the new generator interconnects to the grid, but their full scope is often difficult to quantify at first. Nevertheless, the network benefits will be realized by all transmission users and society as a whole as the transmission system evolves and not be realized solely by the newly interconnecting generator and its customers.

Finally, many network upgrades, although "triggered" at a particular time by an interconnecting generator, may have been necessary anyway at some point to accommodate growing load.

3. Network upgrades produce benefits for all transmission users, not only for the interconnecting generator. As the Commission said in D. 03-06-071 (at p.36):

> As several parties note, it is conceivable that the addition of renewable generation to the grid may result in network benefits, and bidders are encouraged to describe any such potential benefits in their responses. …. The utilities should make it known in their annual plans that such benefits are sought, should apply transparent criteria in evaluating such claims, and should present the results of these evaluations to their PRGs for consideration.

FERC has embraced the principle that a network upgrade produces benefits for all users

1 Generally, the N-1 criterion is the criterion under which transmission planners must ascertain through load flow modeling that needed amounts of power can be delivered after the transmission system experiences the contingency outage of each single element of the transmission system – whether a line or a transformer.

of the network. This principle is the underlying rationale for FERC's policy of "rolling-in" the costs of network upgrades. That is, FERC requires that network upgrade costs be rolled into the bundle of costs borne by all ratepayers and transmission customers and not be borne only by the customers of the generator that paid upfront for the upgrades. In order to accomplish this objective, FERC has established a bright-line test defining network facilities as all facilities beyond the point at which a generator interconnects with the grid. Through crediting mechanisms, FERC requires that the costs of network upgrade facilities be recovered from all users, not just from the users of the interconnecting generator.

4. Failing to account fully for network benefits would produce inefficient results. As noted above, network upgrades benefit the general ratepayer and society as a whole, and not merely the interconnecting generator and its customer. By assessing a bid adder penalty for transmission upgrades against the interconnecting generator without providing any or sufficient offset to that penalty in recognition of the benefits realized by society as a whole, the policy would impute an incremental transmission cost to the generator that is incorrectly high. Such a result would violate elementary economics principles and discourage the interconnection of some cost-effective renewable generation. This loss of efficiency would not be consistent with "least cost best fit" evaluation of bids.

B. The Cost and Delay of Determining for Each Interconnecting Generator the Precise Benefits Is Itself a Substantial Cost Without Clear Benefit

As explained above, the benefits from network upgrades are hard to quantify, and their specific scope and nature, as related to a particular upgrade, may not appear initially. Yet the record on many other upgrades, in terms of wide benefits, is persuasive. Instituting a process in which parties try to identify and quantity the benefits will be unwieldy. For example, as noted above network upgrades not only provide a path for the interconnecting generator to reach load but also provide an alternative path through which other existing and future generators can reach loads. In each specific case, parties would clash over which existing generators, and which future generators, would make us the alternative path, what costs would be saved and which customers would benefit. Similarly, as to the backup or reliability function provided by the upgrade, its precise quantification, and the timing of the benefit, would depend on features of the network that develop later but that parties would argue about now. Further, concerning the reduction in congestion costs and transmission losses, the quantification again would depend on the present and future locations of generators and the types of transactions they undertake. Finally, as noted above, network facilities provide a springboard for further low-cost transmission upgrades and for the addition of other generators, but again the extent of the savings, i.e., the costs that would have been incurred absent the first generator are not knowable.

For all of the foregoing reasons, the Commission after this hearing should determine that the record supports a finding that in the case of each generator interconnection, network benefits will at least equal network costs, thereby obviating a bid adder process. At the very least, the hearing process should aim to answer the question of whether certain types of upgrades have this effect, thereby narrowing the scope of bid adder inquiries that are necessary.

II. Substantive and Technical Issues

Assuming the Commission chooses to continue with the effort to identify costs and benefits of transmission upgrades for purposes of the bid adder, CalWEA offers the suggestions set forth next.

A. Method for determining network benefits

The Commission will need to develop criteria, or a methodology, for determining the network benefits associated with each bid, so that the transmission bid adder reflects the net costs of each bid. The criteria will need to treat each of the issues discussed above in section I.B, among others. CalWEA will attempt to develop recommendations on this point during the hearing process.

B. Method for determining network upgrade costs attributable to generators who have gone through the CAISO process

The Commission stated in D. 03-06-071 (at p.33-34):

> Network facilities: For bidders already in the ISO Queue, the standard ISO System Integration Study (SIS) and Facility Study (FS) will yield sound estimates of network facility costs. (Footnote omitted.)

In general, CalWEA finds that approach acceptable for generators that have gone through the ISO process, with one significant proviso: The final CPUC methodology should adjust the ISO-determined upgrade costs to take account of the "free rider" problem that occurs when a generator is required to fund more upgrade capacity than is needed to accommodate its project. (To illustrate the free rider problem, consider a generator who is first-in-time, has completed its SIS and FS, and has executed an interconnection agreement, and who the CAISO requires to pay for network upgrades that will accommodate twice as much generation capacity as the generator plans to interconnect.) In this proceeding, the parties should consider how to prevent the free rider problem from distorting the bid adder so as not to compound the potential unfairness to the first-in-time generator, while assuring a reasonable assignment of construction risk.

Aside from the “free rider” problem, CAISO-determined upgrade cost estimates tend to be reliable because they are established in an adversarial process in which the generators have a vital interest in minimizing their outlays for network upgrades. In most instances, transmission owners propose and FERC requires (when the transmission owners propose) that generators fund the construction of network upgrades in the first instance and recover those costs through credits to their transmission charges. (Under FERC rules, the utility is free to volunteer to roll in the costs immediately without upfront funding by the generators.) Even though generators have a theoretical right to be repaid over five years through transmission credits for their up-front investments, the process for recovering those credits is cumbersome, and still subject to uncertainty in FERC policymaking; thus recovery is by no means assured. For one thing, CAISO transmission charges are paid by loads, not by generators. Therefore the generators receive no transmission bill on which they would receive a credit; instead they will have to sell the credits to a transmission customer, perhaps at a discount. Second, that recovery is made less certain by the possibility that generators will be awarded financial hedges (FTRs or CRRs) instead of cash for their upgrade costs. The value and fungibility of FTRs is not clear, whereas the cash outlay made by the generators to finance the upgrade upfront is tangible. Lenders will be less inclined to help finance upgrades if they are not sure how and when, and in what currency, they will be repaid.

C. Method for Determining Network Upgrade Costs Caused By Generators Who Have Not Gone Through the ISO Process

1. Procedure for gathering information from generators

CalWEA believes that the information required from generators is well-established by

FERC tariff requirements for generators already in the generation queue and need not be supplemented in this proceeding.

For generators that are not already in the generation queue, PG&E has proposed, appropriately, an information request that is stripped-down from the FERC requirements. CalWEA suggests, however, that wind generators be required to report the extent to which they would be able to produce Volt Amperes Reactive (VARs) to support and regulate voltage in the vicinity of their sites in addition to the information that PG&E proposes to solicit. While some induction generators consume VARs as it produces MW, and therefore requires more transmission capacity per MW produced, other types of generators can produce VARs as well as consume VARs, as can auxiliary facilities that may be associated with the wind generator. In their studies of transmission facilities needed in each cluster, transmission owners should not be allowed to assume that VARs will be consumed.

2. Criteria and methods for establishing cost

In general, CalWEA supports the concept proposed by PG&E, but CalWEA has identified a number of problems in the concept and proposes solutions to those problems.

Cluster concept: PG&E proposes that for each cluster of renewable generation projects expected to interconnect to the existing transmission grid at the same location, the estimated costs for each level of network upgrade necessary to accommodate increasing levels of added generation will be known from studies prepared and made available before the renewable solicitation. (PG&E, p.4-10.)

PG&E’s proposed methodology allows the transmission owner to establish geographic “clusters” in which major aggregations of new generation are expected to locate based on their responses to data requests. Under the PG&E method, the transmission owner would examine its existing base case load flow studies, determine which transmission lines are loaded near 80% of their ratings, and then estimate the costs of relieving constraints (with a constrained line being defined as a line carrying 80% or more of its rating). Upgrade costs would be estimated using typical costs that the transmission owner has experienced in similarly-situated recent upgrades and assuming new generation is interconnected. Although more precise answers could be derived from running additional power flows, PG&E proposes that no such power flows would necessarily be run. PG&E proposes that the utilities determine the following for each prospective interconnection point (or cluster):

1. The amount of available (unused) transmission that exists before network upgrades would be required. (Level 1)
2. The amount of prospective available transmission that would be available after lower cost network upgrades (most cost effective) are made (both MW of availability and $ of upgrades). (Level 2)
3. The cost of network upgrades required to allow all prospective renewable projects to be interconnected at that point (cluster). (Level 3)

One problem with this approach is the lack of specificity with the definition and methodology for determining the Level 2 costs -- what are "lower cost" network upgrades, and how would the MW included be set? Both are very subjective targets. Clearly, some clarification is needed of what PG&E means by the "most cost effective" transmission upgrade. Does it mean the MW achievable through only low-cost fixes such as replacement of potential transformers, current transformers, and a few selective circuit breakers? Does it encompass more expensive bundling of existing conductors and installation of series capacitors? Or does it include even more expensive new poles and wires? In many clusters, there would appear to be a continuum of potential upgrades, and not just a minimum and maximum upgrade. Each upgrade on the continuum would theoretically accommodate a successively larger addition of generation capacity at a successively larger incremental cost per kW of connected generation.

Another major problem is the assumption that upgrades will be required when lines are loaded to "80 percent of their ratings before the new renewable resources are added." PG&E does not specify whether the 80% will be pegged to normal ratings, the higher emergency ratings or (in the case of wind resources as discussed below) whether it will employ dynamic ratings that vary in real time with changes in wind velocities. It is also not clear what is assumed to fill up the remaining 20% of the rating. Perhaps the exercise of developing upgrades will be undertaken by comparing MW of new generation with MW of line capacity and the 20% deadband is left to accommodate VARs.

While it true that induction generators used in many types of wind machines consume substantial quantities of VARs that require additional line capacity, this VAR assumption would not be justified if VAR-producing wind turbines were proposed.

The use of normal line and transformer ratings for the 80% test (as opposed to emergency line ratings or dynamic ratings) would suppress the amount of flow each piece of equipment would be assumed to carry and lead to an overstatement of needed upgrades. That is, without conducting load flow simulation studies with contingencies, the analyst will not be able to estimate the effect of contingencies and would not be justified in using the higher emergency ratings of lines and transformers. One solution to this problem is to require the analyst to employ more precise load flow studies in the development of Level 2 and 3 costs when the simplified method develops high per-unit upgrade costs.

A third problem is that wind generators are uniquely able to take advantage of the fact that transmission lines can safely carry more power when high wind velocities are experienced. Wind generators produce power only when the wind blows, and the line ratings are higher when the wind velocity is higher than that used in setting the line rating because higher velocity winds carry away more heat from line conductors and allow the conductors to carry more power without undue sag. These relationships mean that fewer upgrades may be needed to connect wind generators when wind velocity is taken into account. Equipment that monitors wind velocity and adjusts equipment ratings proportionally is relatively inexpensive. Systems that allow real-time adjustments of equipment ratings to reflect wind velocity is referred to as "dynamic rating." Accordingly, transmission owners should be required to request that wind generators express their willingness to pay for dynamic rating systems and to use dynamic ratings. Wind generators that pay for dynamic rating equipment should receive the FTRs associated with any associated increase in transfer capabilities.

Finally, if a bid includes a proposal to curtail as an alternative to requiring new transmission capacity, that curtailment should be factored into its bid adder.

4. Assigning upgrade costs to bidders

PG&E (at pp. 4-9) describes its method of assigning upgrade costs to generation bidders. The method selects the cheapest generator bid in each cluster for pairing with the cheapest transmission upgrade cost in that cluster. The method would then go on to the second lowest bid and pair it with the second lowest upgrade cost, and so on.

CalWEA finds it logical and desirable, as PG&E also suggests (at pp. 4-11), to allow the first generators in the queue, rather than the generator with the cheapest bid, to obtain the benefit of any previously available transmission capacity. Also, the method of spreading the lower, Level 2, network costs over the lowest ranked resources (those with the cheapest bid, after ranking for direct assignment) as limited by MW size appears to be workable. The upgrade costs could be spread over more than one generating entity, depending upon the size of the generation project and the MW of the associated upgrade blocks.

PG&E suggests that direct assignment facilities include the transformer bank used to step-up the voltage of the generation output to transmission voltage, the outlet line between this step-up transformer and the transmission system, and protection and communication facilities for the resource. (PG&E at pp. 4-5.) If the transformer bank in the substation interconnects several generators directly to the transmission system, these costs should be shared among all generators connected at the substation based on the kW to be interconnected. But if a separate step-up transformer bank is located at each generator's site, there will be no need to allocate the step-up transformer.

5. Methods for dispute resolution

CalWEA has suggested methods for resolving some disputes in the discussion above. More generally, there is a time constraint on resolving disputes because bidders will have only a 90-day notice of the range in which their bid adders may fall before they are called upon to submit a bid. The bid adders for a given cluster will be published in the Transmission Ranking Costs Report. Accordingly, the Commission either needs to (1) employ a relatively expeditious mechanism for resolving disputes that first come to a head upon publication of the Transmission

Ranking Costs Report or (2) provide for the dissemination of cluster data well before the Transmission Ranking Costs Report is released. Armed with this information at an earlier date, generators will be equipped to conduct their own parallel studies of appropriate upgrade costs and to quantify the associated bid adders.

During the 90-day notice period, each bidder will have to assume the worst: that its bid will be matched with the highest upgrade cost. Accordingly, the level 3 per-unit costs will likely become a target for challenges.

CalWEA strongly recommends that, well before publication of the Transmission Ranking Costs Report, transmission owners be required to disseminate basic information such as the base case load flows they are employing (in computer readable form), the amount of capacity in each of the "clusters," and typical costs for transmission equipment in the locale of those clusters.

Respectfully submitted,

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March 2, 2004