

**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 OPINION ON PROCEDURES TO IMPLEMENT THE COST RECOVERY
PROVISIONS OF PUBLIC UTILITIES CODE SECTION 399.25**

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Introduction

Pursuant to Rule 77.3 of the Commission’s Rules of Practice and Procedure, the California Wind Energy Association (“CalWEA”) submits the following comments on the April 25, 2006, Draft Decision of ALJ Halligan (“Draft Decision” or “DD”). Our comments support adoption of the Draft Decision, but strongly urge the Commission to make a few important changes and clarifications.

The Draft Decision interprets the cost recovery assurance provisions of Public Utilities Code §399.25(b)(4) inconsistently with the statutory language. The effect is to narrow the provisions’ application so as to reduce its value in achieving RPS goals. This decision must provide the framework necessary to break the inertia on the many transmission upgrades that will be necessary to meet the state’s Renewables Portfolio Standard (“RPS”) goals. Given the long lead time required to accomplish those upgrades, and the state’s 2010 RPS goal which looms just four years away, RPS success depends on a usable framework now.

Our comments identify the areas in which the Commission must make changes to the Draft Decision so that § 399.25 serves its intended purpose in facilitating the achievement of RPS goals. In the appendix, we have made edits to the text of the Draft Decision to effectuate the changes we recommend. Changes in addition to those discussed here are made for clarity. For example, when referring to eligibility for cost

recovery assurance, the Draft Decision should refer to § 399.25(b)(4) rather than the entire code section.

1. The “last resort” interpretation of § 399.25(b)(4) is far too narrow

The Draft Decision states (at p. 20):

“Section 399.25 is intended to supplement the existing process in circumstances where that process impedes the development of transmission infrastructure necessary to facilitate the state’s renewable energy goals.”

The Draft Decision further states (at p. 24-25):

“Thus, even though the ‘backstop’ exists in § 399.25(b)(4), the intent of the legislation is clear that recovery of renewable transmission costs from retail ratepayers should be made available as a last resort. Therefore, we expect that in addition to filing a certificate application here for any requested facilities, the utilities will also seek recovery at FERC through general transmission rates.”

These characterizations of § 399.25(b)(4) lack specific support in the statutory language. They may have the inadvertent effect of eliminating circumstances in which the provision should operate. Section 399.25 commands the Commission to “take all feasible actions ...to ensure retail cost recovery, with respect to any facility which is necessary to facilitate achievement of RPS goals.” The obligation to “take all feasible actions” includes, but is not limited to, “last resort” situations or situations where a “process ... impedes ... development.”

Similarly, the Draft Decision (at p. 11) limits section § 399.25(b)(4) benefits to facilities that “would not otherwise be constructed absent eligibility for 399.25(b)(4) cost recovery assurance.” The statutory language does contain this condition. This new “would not otherwise be constructed” clause invites speculation and controversy over whether something “otherwise would be constructed.” Absent a Commission order to construct, whether an upgrade would be constructed is a matter of utility volunteerism. How would the Commission determine whether a facility would “otherwise be constructed?” Does the utility have to refuse requests, explicitly, on the specific grounds of financial concerns, for the Commission to make (b)(4) assistance available? Or would

the inquiry ignore a utility's subjective views, instead focusing objectively on what a prudent utility would have done, in light of its RPS obligations and its realistic construction options? What procedure would be used to carry out such inquiry, and over what period of time? Eliminating this standard would save the parties from this impossible inquiry and align the Commission's order with the statute.

Edits to effectuate the needed changes are indicated on appendix pages A-9, A-10, A-11, A-13 and A-14.

2. The Commission must be clear that changing the CAISO tariff would not change FERC policy

The Draft Decision states (at p. 13), referring to FERC's decision on the Antelope Transmission project:

As with the decision to authorize rolled-in treatment for Segments 1 and 2, the decision to reject rolled-in treatment for Segment 3 is no guarantee that similar projects that come before FERC in the future will be denied rolled-in treatment. Nevertheless, barring future changes to the CAISO tariff, it is reasonable to assume that similar gen-tie projects will not be approved for cost recovery through the TAC.

The second sentence suggests a misunderstanding of the relationship between the CAISO tariff and the Commission's network analysis. Whether a facility is network depends on its physical characteristics. If it is a network facility because of its physical characteristics, the facility will be subject to the CAISO tariff. But "future changes to the CAISO tariff" cannot convert a non-network facility into a network facility, which is required for FERC-jurisdictional cost recovery under long-standing FERC policy. (See Section III of CalWEA's January 27, 2006, Opening Brief, beginning at p. 20.)

Edits to effectuate the needed changes are indicated on appendix pages A-6 and A-7.

3. The statute is not limited to transmission upgrades that require CPUC siting approval

At p. 2 (and echoed in several other places), the Draft Decision states "that the provisions of § 399.25 apply to transmission facilities that come before the Commission in the form of a Certificate of Public Convenience and Necessity (CPCN) or Permit to

Construct (PTC) application.” As we explained in our Opening Brief (see section II.A.1), nothing in § 399.25 limits its application to CPCN or PTC facilities. Regardless of whether a facility is small or large, network or non-network, gen-tie or other, cost recovery assurance is the transmission investor's prerequisite. And any one of these types of facilities can be equally critical to achievement of the renewable mandates. That a facility may be exempted from a CPCN or PTC requirement, for example, should not exclude the facility from § 399.25(b)(4) cost recovery eligibility.

Edits to effectuate the needed changes are indicated on appendix pages A-3, A-8, A-12, A-13, A-14, A-16, A-17, A-18, and A-19.

4. The final decision should likewise be more expansive regarding the process for determining facility eligibility, enabling proactive Commission action

As discussed above, the statute requires the Commission to “take all feasible actions...to ensure retail cost recovery, with respect to any facility which is necessary to facilitate achievement of RPS goals.” But the Draft Decision provides only a single path to § 399.25(b)(4) eligibility: certificate proceedings. “All feasible actions” must include two other avenues: utilities seeking eligibility through separate requests, and Commission-initiated findings. In its March 2006 report, for example, the Tehachapi Collaborative Study Group (“TCSG”) recommended (Section 8.5 at p. 113) that the Commission make the judgment now (well in advance of the utility’s CPCN applications) that Phases 2 and 3 of the Tehachapi Transmission Plan are needed for the state to reach its RPS goals. This was one of many actions that the TCSG identified as necessary for the Commission to take if the Tehachapi Transmission Plan is to be completed by 2010.

Edits to effectuate the needed change are indicated on appendix page A-12.

5. The Draft Decision should clarify that facilities other than multiple-generator interconnection facilities must be network

The Draft Decision appropriately excludes single-generator, non-network, interconnection facilities from eligibility under 399.25(b)(4). *See, e.g.*, Draft Decision at p. 22. The Draft Decision also appropriately includes as eligible facilities “high-voltage, bulk-transfer, multi-user transmission facilities, whether classified as ‘network’ or gen-

tie, proposed to access known ‘Renewable Resource Areas’ where economic expansion requires capacity increases that exceed the incremental needs of the typical project.” DD at p. 22. The DD also states (at p. 31, Finding of Fact 4, and echoed elsewhere) that “new transmission facilities” needed to interconnect on [sic] RPS-eligible resource whose developer has entered into a Commission-approved power purchase agreement are eligible for § 399.25 cost recovery.” On this last point, the DD should clarify that “transmission facilities,” if they are not a multiple generator interconnection facility, must be “network” transmission upgrades to be eligible; otherwise, the ambiguity could support arguments that gen-ties are eligible if a power purchase agreement is in place.

Edits to effectuate the needed changes are indicated on appendix pages A-4, A-10, A-18 and A-20.

6. Facilities deemed needed by the CAISO should receive 399.25(b)(4) treatment if they will facilitate RPS goals

The Joint Parties argued that any project that the CAISO determines to be needed pursuant to Section 3.2 of its tariff, which project will also provide RPS-related benefits, should receive § 399.25(b)(4) treatment.. DD at p. 19. The DD (at p. 23) found this proposal “unnecessary” because “projects required by the CAISO for economic or reliability purposes should qualify for cost recovery at FERC.” The DD omits the possibility that FERC will find a CAISO-approved design to be imprudent, and therefore undeserving of FERC-jurisdictional cost recovery. The possibility that FERC’s view of what should have been built could differ from this Commission’s, leading FERC to disallow costs, warrants backstop protection so that utilities concerned about this FERC disallowance risk will proceed. (See TCSG report, Section 7.2 at p. 92.)

Edits to effectuate the needed changes are indicated on appendix pages A-4, A-11, A-12, A-13, and A-18.

7. Conditioning 399.25(b)(4) eligibility on an approved RPS power purchase contract undermines the statutory purpose

The Draft Decision makes an approved RPS contract relevant in two contexts: as a prerequisite for eligibility in the context of a network upgrade, and as one of several

types of evidence of eligibility of a non-network multiple-generator interconnection. The statutory requirement for eligibility is whether the transmission upgrade will facilitate achievement of RPS goals. The Commission can base its decision on factors other than an approved RPS power purchase contract. These factors include the size and quality of the renewable resource involved, as well as the other indicators listed by the Draft Decision. These factors deserve consideration in all eligibility cases except for upgrades deemed needed by the CAISO for economic or reliability reasons (which should receive § 399.25(b)(4) treatment for that reason alone).

As stated on p. 16 of CalWEA’s Opening Brief, “the Commission should avoid reading the "necessary" language [in the § 399.25 statute] to require certainty. The Commission should be looking for an array of evidence, without setting particular thresholds regarding actual project developments. The array of evidence must, taken as a whole, demonstrate that, without the transmission facility, achievement of the state’s RPS goals would be unlikely to occur.”

The TCSG Report (at p. 115) echoes this point, stating, “It is unreasonable for the Commission to expect projects to have executed power purchase contracts and signed interconnection agreements early in the transmission facility permitting stage. ...The Commission must be prepared to make a judgment that there is reasonable assurance that the resource area will be developed if transmission capacity is provided, and that substantial progress toward that end has occurred and is continuing.”

Because the phrase “least-cost and best-fit renewable resources” refers to the bid evaluation process (the only instance where the phrase is applicable under the statute) and necessarily involves the outcome of RPS solicitations, references in the Draft Decision to “least-cost and best-fit” likewise should be replaced with broader references to RPS-eligible resources that will be necessary in achieving RPS goals.

Edits to effectuate the needed changes are indicated on appendix pages A-4, A-13, A-18, and A-20.

8. The decision should state that there is no need to await a specific FERC denial of cost recovery before § 399.25(b)(4) may be applied

The Draft Decision does not directly address the question of whether FERC must have denied cost recovery for an upgrade for that upgrade to be eligible for § 399.25 treatment. One sentence in the DD could be construed to suggest that utilities must seek cost recovery at FERC (see DD at p. 25: "...we expect that in addition to filing a certificate application here for any requested facilities, *the utilities will also seek recovery at FERC through general transmission rates*" (emphasis added)). The Commission should make clear that no such FERC action is required. (See CalWEA Opening Brief at p. 18.)

Edits to effectuate the needed changes are indicated on appendix pages A-8 and A-9.

9. The decision should include the principle that generators should receive reasonable certainty regarding their pro-rata share of transmission costs.

The Draft Decision states (at p. 28), "We emphasize that our intent in granting § 399.25 cost recovery to the utilities is not to relieve the generators of their ultimate cost responsibility for upgrade costs." As the TCSG recommends (TCSG Report at p. 94-95), however, 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. Without this clarification, cost risk is open-ended. Developers don't invest in projects with open-ended cost risks, especially when not under their control.

10. Cost recovery assurance should include environmental study and permitting costs associated with any eligible transmission project

The Draft Decision makes no reference to the kinds of costs that will be included under § 399.25(b)(4). The Commission's decision should make clear that these costs include, but are not limited to, preliminary environmental, siting and transmission studies as well as transmission construction costs. (See CalWEA Opening Brief at pp. 5 and 18.) These items all fit into the Section 399.25(b)(4) category of "transmission costs ... resulting from the construction of the transmission facilities..." The Commission has already included such costs in its Resolution E-3969.

Edits to effectuate the needed changes are indicated on appendix page A-12.

11. The Commission should clarify the treatment of costs not directly assigned to generators.

The Draft Decision states (at pp. 28-29): “[A]s a starting point, we affirm that it is our intent to allocate the excess costs associated with renewable transmission to the ratepayers of all jurisdictional utilities, where appropriate.” We would appreciate clarification of this sentence, in two respects. First, we assume the term “excess costs” refers to costs above those which are assigned solely to the interconnecting generator(s) as well as costs associated with excess capacity resulting because the amount of generation seeking interconnection fell below the amount assumed when the facility was designed and constructed. The term “excess costs” should be clarified in this way.

Second, the phrase “where appropriate” leaves unclear the criteria which will determine who bears what costs when. The phrase is unnecessary. Where costs are prudent and in excess of those assigned directly to the generator, the appropriate allocation is to the ratepayers of jurisdictional utilities, as determined more specifically in utility applications.

Edits to effectuate the needed changes are indicated on appendix page A-15.

12. Smaller proposed points of clarification

a. The decision should use language that avoids confusion regarding state-federal jurisdiction

The Draft Decision refers (at p. 29) to recovering transmission costs through “a separate renewable transmission rate component. Having the state impose a “transmission” charge when the FERC has exclusive jurisdiction over transmission will cause confusion. The word “transmission” should be replaced with “facilities.”

Edits to effectuate the needed changes are indicated on appendix page A-16.

b. The Commission should not minimize the risk of upgrades not facilitating RPS goals

The Draft Decision states that the parties view renewables' access to transmission facilities subject to § 399.25 as a "non-issue." This characterization implies, incorrectly, that there is no role for the California Commission to play. A more accurate characterization of the parties' views, or at least CalWEA's views, is that while (a) access is exclusively subject to FERC jurisdiction, (b) there is a risk that under FERC access rules, transmission capacity designed and intended for renewables could go to non-renewables; and therefore (c) the California Commission can ameliorate this risk by ordering utilities to sign RPS contracts once permits are granted. *See* CalWEA Opening Brief, Section IV, beginning at p. 22. Describing this concern as a "non-issue" misses this point.

Edits to effectuate the needed changes are indicated on appendix page A-16.

Respectfully submitted,

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May 15, 2006

APPENDIX

**TO CALIFORNIA WIND ENERGY ASSOCIATION'S
MAY 15, 2006, COMMENTS ON OPINION ON PROCEDURES TO
IMPLEMENT THE COST RECOVERY PROVISIONS OF P. U. CODE § 399.25**

NOTE: The sections of the Draft Decision in which CalWEA proposes to make changes are either included in their entirety or with large portions excluded as indicated (“...”). Proposed changes are shown in underline and strikeout, with those areas highlighted.

I. Summary¹

In this order, we evaluate and adopt specific policies and procedures to implement the cost recovery provisions of Pub. Util. Code § 399.25. Section 399.25² was enacted on September 12, 2002, as part of Senate Bill (SB) 1078,³ and is intended to facilitate California’s use of renewable energy resources. Section 399.25 directs the Commission to deem necessary those transmission facilities identified in certificate applications if the proposed facilities are necessary to facilitate achievement of the State’s renewable power goals. Section 399.25 also provides a “backstop” cost mechanism allowing the utilities to recover through retail rates any costs of the above facilities that are not approved by the Federal Energy Regulatory Commission (FERC) for recovery through transmission rates. Today’s order clarifies how we intend to implement § 399.25 to provide the utilities and renewable resource developers with the cost recovery assurance to facilitate meeting the Renewable Portfolio Standard (RPS) goals. This decision adopts principles for implementing the requirements of § 399.25 that are in the public interest, because they will assist in our effort to ensure that California has the necessary transmission infrastructure in place in order to meet the RPS goals. The adopted principles are summarized below.

¹ Attachment 1 explains each acronym or other abbreviation that appears in this decision.

² All statutory references are to the Public Utilities Code unless otherwise stated.

³ (Stats. 2002, Ch. 516), adding Article 16 (California Renewables Portfolio Standard Program) to the Cal. Pub. Util. Code § 399.11, *et seq.* (2004) (SB 1078).

- Today's decision reaffirms our finding in Decision (D.) 03-07-033 that the provisions of § 399.25 apply to transmission facilities that **come before the Commission in the form of a Certificate of Public Convenience and Necessity (CPCN) or Permit to Construct (PTC) application and that** are deemed necessary to facilitate meeting the Renewable Portfolio Standard (RPS) goals.
- We modify our prior finding in D.03-07-033 to reflect that the provisions of § 399.25 apply to both "network"⁴ transmission facilities and high-voltage, "generation-tie"⁵ (gen-tie) transmission facilities that are deemed necessary to facilitate the achievement of the RPS goals.
- Findings concerning network benefits pursuant to § 399.25(b)(1) are not a prerequisite to the provision of backstop cost recovery under § 399.25(b)(4). While § 399.25(b) requires the Commission to take "all feasible actions" to ensure that the costs of transmission projects that are necessary to facilitate achievement of RPS goals are fully reflected in rates, including, but not limited to, making findings, where supported by the evidentiary record, that the transmission facilities in question provide network benefits, we find that each of the obligations listed in the four subsections of § 399.25 (b) operate independently of one another, and none is a prerequisite to any other.
- Transmission projects that meet the following qualifying criterion should be considered eligible for § 399.25**(b)(4)** cost recovery: (1) new high-voltage, bulk-transfer, transmission facilities, whether classified as network or gen-tie, that are designed to serve multiple RPS-eligible

⁴ "Network" facilities are defined in FERC Order 2003 as "additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Customer interconnects to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System."

⁵ According to Order No. 2003 generation-tie facilities "include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades."

generators⁶ where it has been established that the amount of added transmission capacity will likely be utilized by RPS-eligible generation projects within a reasonable period of time, and (2) network transmission upgrades that are required to connect RPS-eligible resources with approved RPS power purchase contracts, and upgrades that serve economic or reliability needs that also support RPS goals.

- Requests for § 399.25 cost recovery for upgrades that do not meet the above criterion will be considered on a case-by-case basis in the applicable certificate proceeding.

In adopting these principles, this decision modifies certain findings previously adopted in D.03-07-033 to reflect our further consideration and subsequent events.

II. Procedural History

...

III. Statutory Background

...

FERC's authority over interstate transmission wholesale energy sales stems from § 824 in the *Federal Power Act*. Sections 824(i) and 824(k) give FERC the authority to order interconnection to the grid and to specify the terms of the interconnection.⁷ In 2003, FERC issued its Standard Interconnection Agreement Order⁸ which requires generators to provide upfront funding for network transmission upgrades unless the transmission facility owner volunteers to pay the costs.

⁶ Section 399.12 (a) of Article 16 defines an "Eligible renewable energy resource" as a facility that meets the definition of "in-state" renewable electricity generation facility in Section 25741 of the Public Resources Code.

⁷ *Id.* at 1310-11.

⁸ FERC Order No. 2003, (104 FERC ¶ 61, 103).

...

IV. Implementation of Section 399.25

...

This concern was clearly articulated in SCE's petition for declaratory order seeking rolled-in rate treatment for the Antelope Transmission Projects.⁹ In rendering its decision in response to SCE's petition, the FERC order indicated that it will provide the cost recovery assurance sought by SCE for two of the three transmission projects (Segments 1 and 2) presented by SCE, granting rolled in rate-treatment for all prudently incurred costs, regardless of abandonment or cancellation of the project facilities, provided that certain conditions are met.¹⁰

⁹ Southern California Edison Company's Petition for Declaratory Order, pp. 4-7, March 23, 2005.

¹⁰ FERC Order on Petition for Declaratory Order, Commission Determination, order F. (112 FERC 61,014) The conditions are described by FERC as follows (*id.* at para. 61):

SCE explains that its management does not control the decision to develop or abandon the wind generation projects and that its shareholders do not share the earnings associated with these new wind resources. Further, we note that SCE is developing the Antelope Project pursuant to an order from the CPUC to begin the process for constructing the first phase of the Tehachapi upgrades.¹⁰ Since the Tehachapi area is in SCE's service territory, the CPUC made SCE the party responsible for completing the facilities necessary to increase the delivery of supply to the grid. CPUC has control over the determinations regarding the ultimate design of the Antelope Project. In addition, SCE may be at a higher risk in developing the project because of factors that are beyond SCE's control, such as a generator's decision to continue or terminate development of any given wind farm. SCE also is not a wind developer and therefore will not directly benefit from these facilities.

The costs also have to be prudent. This represents a departure from the conventional rules applied to abandoned plant which limit the utilities's ability to recover prudently incurred costs for abandoned or cancelled facilities to fifty percent. We anticipate that FERC would grant similar relief to all California utilities proposing to make similar investments in network

FERC's willingness to authorize cost recovery through the TAC was based on its view that these segments are appropriately considered network upgrades and the fact that SCE did not have control over the ultimate materialization of the anticipated future generators. This outcome suggests, that at least for network upgrades, utility financing is a viable option. While helpful in the case of Segments 2 and 3 of the Antelope project, and while we can anticipate this treatment to apply in similar situations in the future, the protection offered does not translate into advance assurance of cost recovery because, pursuant to customary FERC practice, the utility may not seek cost recovery until construction is complete. In addition, there remains a possibility that FERC's view of what should have been built will differ from this Commission's.

For these reasons, the FERC's assurances regarding the ability of the utilities to receive cost recovery for network upgrades that they elect to finance, while helpful, do not provide the complete assurance sought by the utility. Despite this favorable outcome with respect to network upgrades, we view the ability of utilities to elect to pay for network upgrades and seek cost recovery through the TAC as only a partial solution for two reasons. First, the FERC decision was specific to segments 1 and 2 of the Antelope Transmission Projects, and thus does not provide any guarantee that future applications seeking rolled-in treatment for similar projects will be approved. Second In addition, FERC rejected rolled in treatment for segment 3 of the Antelope Transmission Projects, on the grounds that the configuration of the project is inconsistent with its

upgrades needed to help facilitate the development of renewable resources and where these conditions are met.

definition of not a network upgrade and thus the project is ineligible for rolled-in rate treatment.

~~As with the decision to authorize rolled-in treatment for Segments 1 and 2, the decision to reject rolled-in treatment for Segment 3 is no guarantee that similar projects that come before FERC in the future will be denied rolled-in treatment. Nevertheless, barring future changes to the CAISO tariff, it is reasonable to assume that similar gen-tie projects will not be approved for cost recovery through the TAC.~~ Thus for transmission projects that are likely to be classified by FERC as gen-tie facilities and for which the most economic build-out involves capacity expansions beyond what is needed for the typical project, the CAISO and FERC-regulated tariffs provide no relief. Developers are unable or unwilling to finance the costs of these facilities, and utilities have no assurance under the existing CAISO tariff current FERC policy of cost recovery if they choose to build them.

...

A. Revisions to D.03-07-033

...

We agree with the majority of parties that the determination of network benefits is not a prerequisite for § 399.25 cost recovery based on a plain reading of the statute. As noted by the parties, the language of § 399.25(b)(4) does not require transmission facilities to be classified as “network” nor does it require a finding of “network benefits” to allow cost recovery through retail rates. While § 399.25(b)(1) requires the Commission to determine whether the network supports findings regarding proposed facility provides network benefits, if such findings are not made, § 399.25(b)(4) still applies. The evaluation of potential network benefits will take place in the applicable certificate proceedings.

...

TURN agrees, and points out that the legislature did not intend for the Commission to provide the § 399.25 backstop only to ensure cost recovery for facilities already eligible for similar treatment, but rather to extend this policy to certain transmission projects not fitting the network description but deemed necessary to achieve the objectives of the RPS program.

CalWEA argues, further, that nothing in § 399.25 limits the cost recovery options in subsection (b) to the commission-authorized construction certificates addressed in subsection (a). Siting processes are unrelated to cost recovery processes, and any type of facility, regardless of certificate requirements, can be critical to achievement of the renewable mandates.

As discussed above, § 399.25(b)(4) does not require the facilities to be network, nor does it exclude gen-tie facilities or require a particular certificate application. Upon further review, we find it appropriate to modify our interpretation of this provision. We find that § 399.25 applies to applications for a certificate authorizing construction of new transmission facilities, either network or multiple-gen-tie, that are deemed necessary to facilitate the achievement of the RPS goals.

CalWEA argues that there is no need to await a specific FERC denial of cost recovery for a particular upgrade in order to proceed with application of § 399.25(b)(4). We agree that, if, at the time of the backstop, the facilities lack FERC cost recovery approval, the statutory test that facilities "are not approved" for cost recovery by the FERC is met.

...

B. Eligibility for § 399.25 Cost Recovery

...

In considering these arguments and implementing § 399.25, we remind parties that § 399.25 is intended to supplement the existing process in circumstances where that process impedes the development of transmission infrastructure necessary to facilitate the state's renewable energy goals. In our view, the scenarios under which the existing processes are likely to impede the development of transmission infrastructure to access renewable resources are limited to those circumstances where the economic expansion of transmission infrastructure requires capacity increases that exceed the capacity requirements of the typical project. This occurs primarily, if not exclusively, in those situations where a large quantity of renewable resources are highly concentrated. As described above, it is under these circumstances that, absent § 399.25, for transmission to be built in as economic a manner as possible, either generators would find themselves paying for capacity in excess of their incremental needs, thus imposing undue burden on their projects, or utilities would find themselves paying for excess transmission capacity without adequate assurance that they will be able to recover the associated costs. In our view, Section 399.25(b) requires the Commission to "take all feasible actions" to ensure retail cost recovery, with respect to any facility which is necessary to facilitate RPS achievement. One of those actions is providing retail rate recovery in (b)(4) for transmission costs which "are not approved" by FERC.

As SCE, TURN, CalWEA, and others points out, however, there are sound reasons for differentiating between lines that link one generation developer's resources with the grid and high-voltage, bulk-transfer, gen-tie lines serving multiple generators. It would not be prudent for a utility to pay for an interconnection sized for a particular generator where only that generator benefits. In particular, By contrast, the bulk transfer gen-tie lines that serve

multiple generators will be easier to develop in a more economic, environmentally-friendly way if they are planned to serve the needs of a large area or several developers. Otherwise, a far greater number of lines by each generator, all competing for right-of-way and causing environmental effects, would have to be constructed. ~~PG&E concurs, stating that the § 399.25 cost recovery should remain a backstop, for use when existing regulatory structures prove inadequate.~~ Any criteria we adopt should harmonize the intention of the statute with the existing regulatory mechanisms.

First, we consider the Joint Parties recommendation that transmission facilities determined through the interconnection process to be needed to interconnect and or deliver power from an RPS-eligible resource whose developer has entered into a Commission-approved power purchase agreement should be deemed eligible for § 399.25 cost recovery.

In our opinion, the fact that a RPS project may count towards meeting RPS goals does not, in and of itself, mean that all the associated transmission facilities are “necessary” to facilitate the goals of the RPS. Under current FERC policy, a single line interconnecting one generation developer’s resources with the grid is paid for by the generation developer. If the line is not constructed by a utility, it is not eligible for § 399.25 cost recovery.

Consequently, while we agree with the parties that network transmission facilities that are required to interconnect an RPS-eligible resource with an approved power purchase agreement are eligible for § 399.25 cost recovery, we expect that non-network transmission upgrades designed to facilitate the achievement of the RPS goals will accommodate multiple RPS-eligible resources. Providing backstop cost recovery for individual gen-tie facilities would unfairly shift the risk and cost of the interconnection facilities to the utility’s retail

ratepayers and protect the utilities and developers from inefficient procurement decisions.

Next, in light of our determination in D.04-06-010 regarding the magnitude and concentration of the renewable resources located in the Tehachapi area and identified in the November 19, 2003 “Renewable Resource Development Report,” “Renewable Resources Development Report,” CEC Publication Number 500-03-030F, November 2003, we find that the costs associated with high-voltage, bulk-transfer, multi-user transmission facilities, whether classified as “network” or gen-tie, proposed to access known “Renewable Resource Areas” where economic expansion requires capacity increases that exceed the incremental needs of the typical project are eligible for cost recovery under § 399.25. Therefore, we find that any high-voltage, bulk-transfer transmission facilities serving multiple generators that provide access to least-cost and best-fit renewable resources concentrated renewable resource areas whose development will be necessary to achieving RPS goals and would not otherwise be constructed are eligible for § 399.25 cost recovery.

Finally, we decline to approve adopt the recommendation that the Commission automatically deem any project that the CAISO determines to be needed pursuant to Section 3.2 of its tariff that will also provide RPS-related benefits to be “necessary to facilitate the RPS goals.” We find this criterion unnecessary since projects needed to facilitate the RPS goals should meet one of the prior two criterion, and projects required by the CAISO for economic or reliability purposes should qualify for cost recovery at FERC. to be reasonable. As we noted above, the cost recovery assurances that the FERC has indicated it will provide do not translate into actual cost recovery assurance because the utility may not seek cost recovery until construction is complete and because

there remains a possibility that FERC's view of what should have been built will differ from this Commission's.

We also note a finding of eligibility for cost recovery is a necessary, though not sufficient, condition for cost recovery through retail rates under § 399.25. Any proposed project must still be approved through a certificate proceeding, where the Commission would conduct CEQA review pursuant to G.O. 131-D.¹¹ Finding that a particular project is "necessary" for the achievement of the RPS goals assumes that the Commission has considered the impacts of, and the alternatives to, the project as required by CEQA. This decision maintains the general rule adopted in D.03-07-033, that the Commission will make the finding of "necessity" in response to the utility's application for a CPCN or PTC for the transmission project.

A finding of eligibility for cost recovery assurance is necessary for each transmission project, including associated study and permitting costs. Utilities may seek a finding of 399.25(b)(4) eligibility in certificate proceedings or in separate requests; the Commission may also make such findings on its own. In each case, The utility must demonstrate in the certificate proceeding that the subject facilities must be found are necessary to achieve the objectives of the RPS program before cost recovery through retail rates will be granted. The degree of certainty required for such a showing will depend on the magnitude of costs at stake. We agree with the parties that in certain all cases except for upgrades deemed by the CAISO to be needed for economic or reliability reasons, it will be necessary to consider the size and quality of the renewable resource involved.

¹¹ See GO 131-D Sections IX.A.1.e. and IX.B.1.c. In addition, CEQA requires the Commission to consider project alternatives in the CPCN or PTC application process.

the status results of the RPS compliance to date, including, but not limited to any approved procurement plans, the results of RPS solicitations, existing bilateral contracts, the number of short listed bidders, the transmission cost studies and requests for system impact studies, etc. This type of probative review will occur as part of the certificate eligibility proceeding for a proposed facility.

Given FERC's decision on SCE's Petition for Declaratory Order, granting rolled-in rate treatment for Segments 1 and 2 of SCE's Antelope Projects, retail ratepayer risk is somewhat limited for network facilities. For facilities classified as "gen-ties," however, retail ratepayer risk exposure remains high. In this situation, we would expect to see a much stronger showing to support a claim that a facility is "necessary to facilitate the achievement of the RPS goals." For example, we would not expect to grant § 399.25 cost recovery treatment to gen-tie facilities absent at least one approved RPS contract. Making the backstop cost recovery contingent upon an RPS contract is consistent with the requirement in the statute that the transmission project be "necessary" to the achievement of RPS goals. As discussed above, § 399.25 is not meant to substitute for the existing cost recovery mechanisms available to support transmission development, nor is it intended to change the ultimate cost responsibility of generators and utility ratepayers.

C. Section 399.25 Cost Recovery Mechanism

The utilities request that we establish the specific ratemaking mechanism for backstop cost recovery under § 399.25 in this order. As discussed above, § 399.25(b)(2) requires the Commission to direct "the utility to which the generator will be interconnected, where the direction is not preempted by federal law, to seek the recovery through general transmission rates of the costs associated with the transmission facilities." In addition, § 399.25(b)(1) and (3)

requires the Commission to support the utility's application at FERC, including making findings, based upon evidence, that the facilities provide network benefits and asserting those positions before FERC. Thus, the intent of the legislation is for both the utilities and this Commission to seek roll-in where possible, but, under § 399.25(b)(4), to provide retail rate recovery assurance where costs "are not approved for recovery in transmission rates" by FERC. Thus, even though the "backstop" exists in § 399.25(b)(4), the intent of the legislation is clear that recovery of renewable transmission costs from retail ratepayers should be made available as a last resort. Therefore, we expect that in addition to filing a certificate application here for any requested facilities, the utilities will also seek recovery at FERC through general transmission rates.

TURN, the Joint Parties, and CalWEA notes that the Commission should consider approving cost recovery treatment for eligible projects in advance of FERC action if the project is unlikely to be eligible for rolled in ratemaking under the existing FERC policy. TURN argues that unless there are clear indications that the facility qualifies as a network upgrade, the Commission should not defer a cost recovery request. We agree.

...

D. Cost Allocation

...

We emphasize that our intent in granting § 399.25 cost recovery to the utilities is not to relieve the generators of their ultimate cost responsibility for upgrade costs, but instead is to facilitate up-front funding of economically sized upgrades wherever possible, and to ensure that sufficient transmission exists to meet the RPS goals. The mechanism that is adopted for generator cost-sharing, however, should be based on each generator's pro-rata share according to usage.

and should provide the generator with a reasonable degree of certainty regarding the amount of the charge. We find that the discussion on cost allocation was largely inadequate to develop a specific cost allocation methodology. However, as a starting point, we affirm that it is our intent to allocate the excess costs associated with renewable transmission – i.e., costs above those which are assigned solely to the interconnecting generator(s) as well as costs associated with excess capacity resulting because the amount of generation seeking interconnection fell below the amount assumed when the facility was designed and constructed -- to the ratepayers of all jurisdictional utilities, where appropriate. This is consistent with our belief that the benefits of the RPS program in general, and transmission access to renewable resources in particular, accrues to all users of the California grid, not merely the customers of the utility constructing the transmission facilities. We therefore invite the utilities to file an application for allocation of renewable transmission costs when facilities subject to § 399.25 cost recovery are placed in service.

We also agree with TURN that cost associated with renewable transmission facilities to be recovered from retail ratepayers pursuant to § 399.25 should not be recovered through distribution rates, and should instead be recovered through a separate renewable transmission facilities rate component.

E. Access to Renewable Transmission Facilities

The ACR requested comments on whether it was necessary or appropriate to attempt to ensure access on transmission facilities funded under the backstop cost recovery provisions set forth in § 399.25 for renewable resources.

The parties responded by noting that access by renewable resources to transmission facilities that are subject to cost recovery under § 399.25 is a non-issue, although a concern, is inappropriate to address here because all

transmission facilities built by the utilities will be turned over to CAISO operational control, and will therefore be subject to FERC-approved open access rules which provide grid access on a nondiscriminatory basis based on competitive bids. Any market participant desiring access to the CAISO grid, and willing to pay the marginal costs of obtaining such access (paying for the marginal costs of congestion and losses), is assured access.

F. Construction Triggers

The ACR requested comments on what triggers or conditions, if any, were necessary to protect ratepayers from stranded or excessive costs associated with the permitting and construction of large scale transmission upgrades. The majority of the parties, including the utilities and the CAISO, do not recommend establishing specific triggering criteria for future transmission projects at this time. Instead, they suggest that the Commission consider developing permitting and construction triggers on a case-by-case basis in the applicable **certificate** applications. Such triggers could reflect the need for additional renewable power to meet RPS goals, the level of utilization and/or commitment for existing phases and proposed phases, and the potential market for additional renewable power.

Alternatively, SDG&E suggests that to minimize the risk of stranded investment, “trunk lines” could be permitted in advance of contractual commitments to facilitate their development in the future. Then, once permits are in hand, the utility could hold an open season to solicit contracts for the development of new renewable projects. Actual construction of the trunk line would only commence once contracts are in place ensuring that a sufficient quantity of generation will be built. Under SDG&E’s proposal, the subject transmission facilities would only be built upon a determination that there were

sufficient commitments to add generation in the remote area, so there should be no “under-utilization” of transmission capacity and the Commission’s backstop ratemaking authority should permit transmission providers to recover the full amount of costs that the FERC does not allow to be recovered through FERC-jurisdictional rates.

We agree with the parties’ recommendation to consider any necessary triggers in the applicable certificate proceedings.

V. Comments on Draft Decision

The draft decision of Administrative Law Judge (ALJ) Halligan was mailed to the parties in this proceeding in accordance with Section 311(g)(1) and Rule 77.7 of the Rules of Practice and Procedure. Comments were filed on _____ by _____. Reply comments were filed on _____ by _____.

VI. Assignment of Proceeding

Dian Grueneich is the assigned Commissioner and Julie Halligan is the assigned ALJ in this proceeding.

Findings of Fact

1. The provisions of § 399.25 apply to applications for transmission line construction subject to the Commission’s siting jurisdiction, either network or gen-tie; transmission facilities that are deemed necessary to facilitate the achievement of the RPS goals.

2. A finding of “network benefits” pursuant to § 399.25(b)(1) is not a prerequisite for backstop cost recovery under § 399.25(b)(4), nor is the provision of cost recovery assurance dependent upon a certificate requirement; these two provisions are of the code function independently of one another.

3. High voltage, bulk-transfer transmission facilities, whether classified as network or gen-tie, that are designed to serve multiple RPS-eligible generators

where it has been established that the amount of added transmission capacity will likely be utilized by RPS-eligible generation projects within a reasonable period of time are eligible for § 399.25 cost recovery.

4. New Network transmission facilities needed to accommodate the output of on an RPS-eligible resource whose developer has entered into a Commission-approved power purchase agreement are eligible for § 399.25 cost recovery and upgrades that serve economic or reliability needs where the upgrade will facilitate RPS goals are eligible for § 399.25 cost recovery.

5. To protect ratepayers from the risk associated with unnecessary facilities, we do not anticipate requiring a stronger showing to support a claim that finding gen-tie facilities used by multiple facilities are to be necessary to facilitate the achievements of the RPS goals absent at least one approved RPS contract.

6. Costs associated with renewable transmission facilities to be recovered from retail ratepayers pursuant to §399.25 should not be recovered through distribution rates.

Conclusions of Law

1. The Commission's ability to authorize retail rate recovery of transmission upgrade costs pursuant to § 399.25(b)(4) does not interfere with the FERC's jurisdiction over transmission ratemaking such that it would be preempted by federal law.

2. The Commission does not have the authority to require transmission owners to provide up-front funding for transmission upgrades.

3. In order to proceed as expeditiously as possible with the implementation of § 399.25, this decision should be effective today.

INTERIM ORDER

IT IS ORDERED that:

1. The provisions of Section 399.25 apply to transmission facilities that ~~come before the Commission in the form of a Certificate of Public Convenience and Necessity or Permit to Construct application and that~~ are deemed necessary to facilitate the Renewable Portfolio Standard (RPS) goals ~~through that process~~.

2. The provisions of § 399.25 apply to both “network” transmission facilities and high-voltage generation-tie (gen-tie) transmission facilities that are deemed necessary to facilitate the achievement of the RPS goals.

3. Transmission projects that meet the following criteria are eligible for § 399.25 cost recovery: (1) new high voltage, bulk-transfer, transmission facilities, whether classified as network or gen-tie, that are designed to serve multiple RPS-eligible generators where it has been established that the amount of added transmission capacity will be likely to be utilized by RPS-eligible generation projects with a reasonable period of time, and (2) network transmission upgrades that are ~~required to connect RPS-eligible resources with approved power purchase contracts~~ deemed necessary to facilitate the RPS goals.

This order is effective today.

Dated _____, at San Francisco, California.