STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION
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SAN FRANCISCO, CA 94102-3298

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Ratesetting

TO PARTIES OF RECORD IN RULEMAKING 06-02-012

This is the proposed decision of Administrative Law Judge (ALJ) Anne E. Simon, previously designated as the presiding officer in this proceeding. It will not appear on the Commission's agenda for at least 30 days after the date it is mailed. This matter was categorized as ratesetting and is subject to Pub. Util. Code § 1701.3(c). Upon the request of any Commissioner, a Ratesetting Deliberative Meeting (RDM) may be held. If that occurs, the Commission will prepare and publish an agenda for the RDM 10 days beforehand. When the RDM is held, there is a related ex parte communications prohibition period. (See Rule 8.2(c)(4).)

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the proposed decision as provided in Article 14 of the Commission's Rules of Practice and Procedure (Rules), accessible on the Commission's website at www.cpuc.ca.gov. Pursuant to Rule 14.3, opening comments shall not exceed 15 pages.

Comments must be filed either electronically pursuant to Resolution ALJ-188 or with the Commission's Docket Office. Comments should be served on parties to this proceeding in accordance with Rules 1.9 and 1.10. Electronic and hard copies of comments should be sent to ALJ Simon at aes@cpuc.ca.gov and assigned Commissioner. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

s/ ANGELA K. MINKIN
Angela K. Minkin, Chief
Administrative Law Judge

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Attachment

Decision **PROPOSED DECISION OF ALJ SIMON (Mailed 10/29/2008)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop Additional Methods to Implement the California Renewables Portfolio Standard Program.	Rulemaking 06-02-012 (Filed February 16, 2006)

(See Appendix D for a list of appearances.)

DECISION AUTHORIZING USE OF RENEWABLE ENERGY CREDITS FOR COMPLIANCE WITH THE CALIFORNIA RENEWABLES PORTFOLIO STANDARD

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DECISION AUTHORIZING USE OF RENEWABLE ENERGY CREDITS FOR COMPLIANCE WITH THE CALIFORNIA RENEWABLES PORTFOLIO STANDARD

1. Summary

This decision authorizes the use of unbundled and tradable renewable energy credit (TRECs) for compliance with the California renewables portfolio standard (RPS) program. It also delineates the structure and rules for a TREC market and for the integration of TRECs into the RPS flexible compliance system.

The use of TRECs for RPS compliance will provide more options and flexibility for RPS-obligated load-serving entities (LSEs) to comply with RPS mandates in both the near and longer term. Over time, it will also provide additional resources and incentives for the development of RPS-eligible generation.

The market and compliance rules are developed with a view to simplicity, transparency, fairness, and ease of administration. These market and compliance structures are intended to remain the framework for the use of TRECs into the future. Although the TREC market may be modest in the next two or three years, the market rules put in place in this decision will both allow a new market to develop and provide robust rules for a mature TREC market. The rules create a market in which participation in TREC transactions is not restricted, though participants must meet the requirements set forth by this Commission for REC trading, as well as any requirements for participation set by the Western Renewable Generation Information System (WREGIS). In order to promote market liquidity while preserving the value of TRECs for RPS procurement planning, TRECs may be held for up to three years from their date of creation before they must be committed to use for RPS compliance.

Once committed to RPS compliance, TRECs will be treated in substantially the same way as bundled energy purchases for reporting and compliance purposes. This includes application of most flexible compliance mechanisms, with the principal exception that TRECs can not be earmarked for use to make up deferred compliance. In order to promote a robust TREC market, the decision allows TRECs from existing RPS contracts to be unbundled and sold under certain conditions. To protect ratepayers from excessive payments for TRECs in the early stages of the TREC market, a transitional price cap on RECs used for RPS compliance by investor-owned utilities will be instituted, with opportunities for review as the TREC market matures. The decision also clarifies that certain transactions with RPS-eligible renewable generation located outside of California will be treated as REC-only transactions for RPS compliance purposes.

In order to facilitate the integration of the use of TRECs into the RPS program, this decision authorizes Energy Division staff to begin a process of revising the RPS compliance documents and reporting protocols.

Finally, the decision sets forth two standard terms and conditions (STCs) related to RECs that must be used in all RPS contracts and one additional STC governing Commission approval of REC-only contracts.

Because this decision concludes the consideration of the issues identified for this proceeding (with the exception of three related issues that are transferred to Rulemaking 08-08-009 for disposition), this proceeding is closed.

2. Introduction

In Pub. Util. Code § 399.11,[1] the Legislature set up the RPS program:

> [i]n order to attain a target of generating 20 percent of total retail sales of electricity in California from eligible renewable energy resources by December 31, 2010, and for the purposes of increasing the diversity, reliability, public health and environmental benefits of the energy mix. . . (§ 399.11(a).)[2]

In Senate Bill (SB) 107 (Simitian), Stats. 2006, ch. 464, the Legislature gave this Commission express authority to allow the use of TRECs for RPS

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[1] RPS legislation is codified at Pub. Util. Code §§ 399.11-399.20. Unless otherwise indicated, all subsequent citations to sections refer to the Public Utilities Code, and citations to rules refer to the Rules of Practice and Procedure, which are codified at Chapter 1, Division 1 of Title 20 of the California Code of Regulations.

[2] The Legislature also described the benefits to be expected from the RPS program:

> (b) Increasing California's reliance on eligible renewable energy resources may promote stable electricity prices, protect public health, improve environmental quality, stimulate sustainable economic development, create new employment opportunities, and reduce reliance on imported fuels.
>
> (c) The development of eligible renewable energy resources and the delivery of the electricity generated by those resources to customers in California may ameliorate air quality problems throughout the state and improve public health by reducing the burning of fossil fuels and the associated environmental impacts and by reducing in-state fossil fuel consumption.
>
> (d) The California Renewables Portfolio Standard Program is intended to complement the Renewable Energy Resources Program administered by the State Energy Resources Conservation and Development Commission and established pursuant to Chapter 8.6 (commencing with Section 25740) of Division 15 of the Public Resources Code.

compliance. Section 399.16 provides both the authorization and several conditions on its exercise.[3]

This decision implements this authorization in light of the overarching purposes of the RPS program. It seeks to improve compliance opportunities for RPS-obligated LSEs and to provide incentives for the construction of new RPS-eligible generation. The decision builds on several years of experience with planning, procurement, reporting, and compliance in the use of bundled energy contracts for RPS compliance. It relies on the new tools provided by WREGIS for recording, tracking, and trading TRECs in order to develop the market rules and integrate the use of TRECs into the RPS compliance framework.

3. Procedural Background

The history of the consideration of the use of TRECs in the RPS program was presented in detail in D.08-08-028 and will not be repeated here. This section addresses the procedural steps in this proceeding.

Rulemaking (R.) 06-02-012, the Order Instituting Rulemaking (OIR) for this proceeding, was issued in the framework of the original RPS legislation, SB 1078 (Sher), Stats. 2002, ch. 516. In the OIR, the Commission identified issues related to tradable RECs as an important component of the proceeding. The Scoping Memo and Ruling of Assigned Commissioner (April 28, 2006) set out a number of issues related to tradable RECs, and assigned them to the second portion of this proceeding.

A staff white paper, "Renewable Energy Certificates and the California Renewables Portfolio Standard Program" (REC white paper), was published

[3] For ease of reference, § 399.16 is reproduced as Appendix A.

April 20, 2006.[4] Comments on the REC white paper were filed in late May 2006; reply comments were filed on June 14, 2006.[5]

Among other things, the REC white paper set out definitions of terms that have been used throughout the subsequent consideration of the use of RECs for RPS compliance. The Commission adopted the white paper's definitions of "unbundled" RECs and "tradable" RECs in D.06-10-019:

> Under an unbundled REC regime, claim over the renewable attributes of energy produced by eligible renewable technologies can be transferred from the renewable generator to one [load-serving entity] LSE while the energy is delivered to another. However, once this transfer occurs, claim over the attributes cannot be resold. In contrast, under a tradable REC regime, although the concept of selling the energy and claim over the attributes to different parties remains intact, RECs may be transferred from the renewable generator to any third party, not just obligated LSEs. In

[4] The REC white paper may be found at http://www.cpuc.ca.gov/word_pdf/REPORT/55606.doc.

[5] Comments were filed by Central California Power; Sustainable Conservation; Powerex Corp.; California Solar Energy Industries Association (CalSEIA), Clean Power Markets, Inc., PV NOW, Vote Solar Initiative (jointly); Pacific Gas & Electric Company (PG&E); Mountain Utilities; Division of Ratepayer Advocates (DRA); Southern California Edison Company (SCE); San Diego Gas & Electric Company (SDG&E), Pilot Power Group, Inc.; Alliance for Retail Energy Markets (AReM), Western Power Trading Forum (WPTF) (jointly); Aglet Consumer Alliance (Aglet); Green Power Institute (GPI); Center for Energy Efficiency and Renewable Technologies (CEERT); Independent Energy Producers Association (IEP); Union of Concern Scientists (UCS); The Utility Reform Network (TURN); and California Large Energy Consumers Association and California Manufacturers and Technology Association (jointly).

Reply comments were filed by Central California Power, CEERT, GPI, Aglet, Pilot Power, AReM, SDG&E, SCE, Mountain Utilities, UCS, TURN, PG&E, Powerex, and IEP.

addition, these attributes can be resold subsequent to the initial sale.[6]

In D.06-10-019, the Commission decided not to authorize the use of unbundled RECs for RPS compliance at that time. We stated that we would consider the use of unbundled and/or tradable RECs later in this proceeding.[7]

The Amended Scoping Memo and Ruling of Assigned Commissioner (December 29, 2006) (Amended Scoping Memo) revised the tasks for this proceeding, in light of prior work and the enactment of SB 107, effective January 1, 2007. The Amended Scoping Memo identified three areas related to tradable RECs:

- Exploring the use of tradable RECs for RPS compliance by all RPS-obligated LSEs, including determining what attributes should be included in a REC;

- Determining the appropriate treatment of RECs associated with energy generated by renewable customer-side distributed generation, after examination of two important issues—measurement of renewable output from customer-side distributed generation, and analysis of the impact of ratepayer subsidies of renewable distributed generation—in R.06-03-004; and

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[6] REC white paper, p. 1, n. 1; D.06-10-019, p. 33.

[7] Unless clarity requires a different usage, we will refer to unbundled and tradable RECs together as "tradable RECs." Following the usage of Energy Division and the parties, tradable RECs may also be called TRECs. We will refer to transactions using unbundled and/or tradable RECs as "TREC transactions" or "REC-only transactions." If the context requires a reference to "RECs" because, for example, the RECs were procured through a bundled contract, the RECs so referenced should be presumed to be tradable (unless they are RECs governed by §§ 399.16(a)(5) or (6)).

- Determining the status of RECs associated with renewable energy generated by qualifying facilities (QFs) under contract with California utilities.

The Second Amended Scoping Memo and Ruling of Assigned Commissioner (February 25, 2008) (Second Amended Memo) noted several developments related to the use of TRECs for RPS compliance since the issuance of the Amended Memo. These changes resolved some of the previously identified issues, added new tasks, and moved other issues forward.

In D.07-01-018, issued in R.06-03-004, the Commission determined that RECs associated with customer-side renewable distributed generation belong to the DG system owner, irrespective of participation in net-energy metering, the California Solar Initiative, or the Self Generation Incentive Program.

SB 107 resolved the status of RECs for renewable energy generated by QFs by prohibiting the creation of RECs associated with energy from QFs under contracts executed after January 1, 2005; it also allowed the creation of RECs from energy under any contract prior to January 1, 2005 only if the contract explicitly addressed the ownership of RECs.[8]

SB 107 also added the requirement that, in order for us to authorize the use of TRECs for RPS compliance, this Commission and the California Energy Commission (CEC) must each make a determination that the CEC's RPS tracking system (including WREGIS) is ready to support the use of unbundled and/or tradable RECs for RPS compliance.[9] A draft joint staff report on the tracking

[8] Pub. Util. Code §§ 399.16(a)(6), (5).

[9] Section 399.16(a)(1).

system was issued March 7, 2008.[10] A draft final joint staff report was attached to Draft Resolution (Res.) E-4178, mailed September 23, 2008.

Energy Division staff held a comprehensive workshop on TRECs and RPS compliance on September 5-7, 2007 (TRECs workshop).[11] After the workshop, staff prepared a revised straw proposal (Straw Proposal) covering a number of TREC market and compliance issues. The Straw Proposal was circulated to parties with the Administrative Law Judge's (ALJ) Ruling Requesting Post-Workshop Comments on Tradable Renewable Energy Credits (October 16, 2007) (post-workshop ruling). Parties filed and served pre-workshop comments on August 17, 2007.[12] Post-workshop comments were filed on November 13, 2007.[13] Post-workshop reply comments were filed on December 5, 2007.[14]

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[10] The draft report may be found at http://www.energy.ca.gov/2008publications/CEC-300-2008-001/CEC-300-2008-001-SD.PDF.

[11] The workshop notice and the assigned administrative law judge's rulings seeking pre-workshop and post-workshop comments were circulated to the service lists in this proceeding, R.06-05-027 (RPS administration), R.06-03-004 (distributed generation and California Solar Initiative), and R.06-04-009 (greenhouse gas policy). The workshop presentations are available at http://www.cpuc.ca.gov/PUC/energy/electric/RenewableEnergy/misc/recpresentations.htm.

[12] Pre-workshop comments, in response to the ALJ's Ruling Requesting Pre-Workshop Comments on Tradable Renewable Energy Credits (July 19, 2007), were filed by Central California Power; Powerex, Solar Alliance; PacifiCorp; CEERT; Sustainable Conservation; AReM and WPTF (jointly); CalpinePowerAmerica-CA, LLC; Coral Power, LLC; SDG&E; Aglet; IEP; PG&E; UCS; SCE; GPI; PPM Energy, Inc.; CPV Renewable Energy Company, LLC; and Sempra Energy Solutions.

[13] Post-workshop comments were filed by PG&E; GPI; Powerex; SDG&E; Golden State Water Company; IEP; Pilot Power; Central California Power; EcoSecurities; DRA; CEERT; Calpine Corporation and CalpinePowerAmerica-CA, LLC (jointly); AReM and

Footnote continued on next page

At the prehearing conference held December 10, 2007, some parties suggested that parties interested in the subject might try to develop a consensus recommendation on the definition and attributes of a TREC. Informal discussions among the parties were publicized to the service lists in this proceeding, R.06-05-027, R.06-03-004, and R.06-04-009. The discussions did not result in the filing of any recommendations on this topic. On May 9, 2008, the Center for Resource Solutions (CRS) filed a Motion for Leave to File Additional Comments related to REC definition and attributes. This motion was granted by an ALJ's ruling on June 6, 2008.[15] The ruling allowed reply comments to be filed not later than June 11, 2008.[16] Following this round of comments, the Commission issued D.08-08-028, on the definition and attributes of a REC.[17]

WPTF (jointly); Mountain Utilities; SCE; TURN; PacifiCorp; California Farm Bureau Federation and Sustainable Conservation (jointly); Solar Alliance and CalSEIA (jointly).

[14] Post-workshop reply comments were filed by Central California Power; PacifiCorp; Aglet; UCS; California Farm Bureau Federation, Inland Empire Utilities Agency, Sustainable Conservation (jointly); Recurrent Energy, Inc., Solar Alliance, CalSEIA (jointly); Calpine Corporation and CalpinePowerAmerica-CA, LLC (jointly); TURN; IEP; AReM; SCE; Mountain Utilities; CEERT; SDG&E; DRA; GPI; and PG&E.

[15] Parties were notified informally by e-mail on May 28, 2008.

[16] Reply comments were filed on June 11, 2008 by AReM and WPTF (jointly; collectively, AReM); DRA; GPI; IEP; SCE, PG&E, PacifiCorp, Sierra Pacific, and SDG&E (jointly; collectively, IOUs); Solar Alliance and CalSEIA (jointly; collectively, Solar Alliance); TURN; and UCS.

[17] Although the definition of a REC is central to the tradability of a REC, the details of D.08-08-028 are largely not relevant to this decision. One convention that should be kept in mind throughout the discussion, however, is that one REC represents the environmental and renewable attributes associated with one megawatt-hour (MWh) of RPS-eligible generation. See WREGIS Operating Rules, section 2, which may be found at http://www.wregis.org/content/blogcategory/26/47/.

Several significant developments have occurred since the TRECs workshop, including issuance of D.08-08-028, ongoing implementation of the California Global Warming Solutions Act of 2006, Assembly Bill (AB) 32 (Núñez/Pavley), Stats. 2006, ch. 488, and the CEC's revisions to its criteria for delivery of RPS-eligible generation in its *Renewables Portfolio Standard Eligibility Guidebook (Eligibility Guidebook)*, pp. 23-26 (3d ed. December 19, 2007).[18] In order to allow parties an opportunity to update their positions on TRECs, the ALJ issued a Ruling Requesting Supplemental Comments on the Use of Tradable Renewable Energy Credits for the Renewables Portfolio Standard Program (supplemental comment ruling) on September 4, 2008. Comments were filed on September 12, 2008[19] and reply comments were filed September 18, 2008.[20]

4. Discussion

The RPS statute authorizes but does not require this Commission to allow the use of TRECs for RPS compliance, subject to certain statutorily-imposed conditions. It also provides specific direction on the treatment of several aspects of the use of TRECs for RPS compliance. Since the specific statutory guidance is relevant only if the use of TRECs is authorized, we begin with the issue of whether to authorize the use of TRECs for RPS compliance.

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[18] The *Eligibility Guidebook* is available at http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-ED3-CMF.PDF.

[19] Comments were filed by Aglet, AReM, Bear Valley Electric Service (BVES), Calpine, CEERT, DRA, GPI, Horizon Wind Energy and Iberdrola Renewables (jointly; collectively, Horizon), IEP, Mountain Utilities, PG&E, PacifiCorp, Powerex, SDG&E, SMUD, SCE, UCS, and Wal-Mart.

[20] Reply comments were filed by Aglet, AReM, IEP, Large-scale Solar Association, PG&E SCE, SDG&E, TURN, and UCS.

4.1. Authorization

The statute does not set out any criteria or standards by which this Commission should judge whether to authorize the use of TRECs, thus leaving this fundamental matter in our discretion. Almost all parties urge that the use of TRECs for RPS compliance be authorized. They advance a variety of reasons, focused on facilitating RPS compliance and promoting development of new RPS-eligible generation. Several parties assert that the use of TRECs will allow RPS procurement to avoid problems of transmission congestion.[21] Some parties argue that the availability of TRECs will make the overall RPS procurement process more efficient, by providing LSEs with additional options for procurement.[22] According to some parties, the use of TRECs will make it easier for RPS-obligated LSEs[23] to achieve their annual procurement targets (APTs).[24] With the use of TRECs, overall compliance costs for RPS-obligated LSEs should be lower, some parties claim.[25] Finally, some parties assert, the availability of a revenue stream from TRECs and options that may create for developers will promote development of new RPS-eligible generation.[26]

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[21] AReM, Central California Power, and IEP.

[22] AReM, Horizon, PacifiCorp, SDG&E, PG&E.

[23] RPS-obligated LSEs comprise regulated utilities, community choice aggregators (CCAs), and electric service providers (ESPs). In this decision, utilities are sometimes referred to in groupings of "large utilities" (PG&E, SCE, SDG&E), "small utilities" (Bear Valley Electric Service and Mountain Utilities), and "multi-jurisdictional utilities" (PacifiCorp and Sierra Pacific).

[24] AReM, IEP, PG&E, and SDG&E. GPI and UCS are less certain, but suggest this could be a benefit.

[25] CEERT, IEP, PG&E, and SDG&E.

[26] AReM, CEERT, Coral Power, Horizon, IEP, PG&E, and SDG&E.

DRA and TURN are skeptical about the use of TRECs for RPS compliance; Aglet opposes it outright. These parties believe that use of TRECs will not improve the RPS program and is unlikely to lead to development of new RPS-eligible generation.

TURN and DRA express concern that the TREC pricing experience in other jurisdictions suggests that TREC prices are likely to be volatile. This would harm consumers and would not provide reliable financing for new renewable projects. Aglet, DRA and TURN suggest that the use of TRECs would lead to a market that overpays for TRECs from existing facilities, and thus would harm consumers and not contribute to new generation. Aglet asserts that the availability of transmission is a major constraint for the development of new RPS-eligible generation; TRECs can not solve that problem, because a new generation facility will not be built if transmission is not available. Both TURN and Aglet express concern that reliance on TRECs rather than long-term bundled contracts will reduce the physical hedging value of RPS procurement. TURN also raises questions about possible hoarding of TRECs and exercise of market power within the TRECs market.

Several of the TREC proponents' arguments are somewhat overstated and do not acknowledge some real problems. It is true that TRECs can expand RPS compliance options, but without new RPS-eligible generation, a robust TREC market to deliver TRECs for RPS compliance will not develop quickly. It is true that TRECs can allow transfer of RPS credit without regard to constrained transmission pathways, but only if there are both RPS-eligible generation to produce the energy associated with the REC and new transmission pathways. Current RPS flexible compliance rules also allow LSEs to take delivery of RPS-

eligible energy anywhere in the state, thus reducing the impact of transmission constraints.

The TREC skeptics, on the other hand, focus solely on negative possibilities, such as hoarding of TRECs and loss of interest in the development of new RPS-eligible generation in California. They also argue that consumers may be harmed by high or volatile TREC prices, and TURN and Aglet propose measures to mitigate those harms. But they do not appear to have confidence that the mitigation strategies they propose will have a positive impact.

Considering all the arguments, the benefits of allowing the use of TRECs for RPS compliance substantially outweigh the potential harms. Greater compliance flexibility, procurement efficiency, and potentially lower costs are real benefits, even if they may be relatively small in the early years of a TREC market. The availability of a revenue stream from TRECs may encourage new renewable development. Though many other factors, such as transmission siting, are also important determinants of new renewable development, the possibility of more money, or money arranged more flexibly, is only a plus for possible development. Furthermore, a TREC market will provide important pricing information to developers and the investment community, potentially providing them greater confidence in the long-term financial viability of renewable energy projects.

The possible negative consequences of TRECs, such as high payments to existing facilities, market manipulation, or high prices, can be mitigated or removed by the rules this Commission sets for the use of TRECs and the design of the TREC market. Additionally, some of these problems, specifically high payments to existing facilities, are not inherent or unique to TRECs, but are problems that can exist in a bundled regime as well. Such issues might be better

resolved through changes in the relevant statutes or guidelines governing RPS eligibility. This decision sets rules to allow the best chance for a healthy TREC market to develop and aid in the attainment of California's RPS goals.

We therefore exercise the discretion granted to this Commission in § 399.16(a) to authorize the use of unbundled and tradable RECs for RPS compliance, in accordance with the rule set forth in this decision.[27]

4.2. Sources of TRECs

Our decision to authorize the use of TRECs for RPS compliance is not based on any estimate of the probable quantity of TRECs that may be available in the near term. A brief review of that topic can, however, usefully inform our design of any interim, transitional rules or requirements for the market and for the RPS flexible compliance regime.

Parties were asked to present their best quantitative estimates of the sources of TRECs that could be available for California RPS compliance in the period ending January 1, 2012. From those estimates it is possible to develop a broad-brush picture of the TREC landscape for the near future.

4.2.1. Larger-Scale RPS-Eligible Generation

Calpine suggests that essentially all RPS-eligible generation in California that is or will be capable of delivering energy by the end of 2010 is already under contract to one of the large investor-owned utilities (IOUs). This assertion is not disputed.

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[27] This authorization is qualified by the restrictions on the use of RPS-eligible generation from facilities with contracts prior to 2005 in which the ownership of RECs is not specified, and from QFs with contracts signed after January 1, 2005. (§§ 399.16(a)(5),(6).) These restrictions are discussed further in § 4.7 below.

In response to a question posed in the ALJ's post-workshop ruling, several parties provided estimates, of varying precision, of possible sources of TRECs for the period until the end of 2011. Evolution Markets and UCS submitted the most substantial information, which was reasonably consistent. Evolution Markets estimates that existing RPS-eligible wind and biomass facilities in the Northwest might provide up to 1,100 megawatts (MW) of RPS-eligible nameplate capacity, while planned new geothermal, wind, biomass or biogas generation throughout the Western Electricity Coordinating Council (WECC) region could provide up to 7,500 MW of nameplate capacity. UCS estimates that the Northwest might supply up to 4000 MW of new nameplate capacity. The timeframe within which any of the projects included in these estimates might be built is not, however, clear. Nor is it possible for the parties to suggest what proportion of such new generation might be available to California LSEs, whether in the form of bundled energy contracts or REC-only purchases.

Other parties[28] point to smaller and more diffuse potential sources, such as small hydropower generation, excess renewable generation from publicly owned utilities, or RPS-eligible QFs whose contracts with large utilities expire and are not renewed, but which still will produce RPS-eligible generation.[29]

PG&E and SCE each state that new merchant RPS-eligible generation is not a reasonable source of TRECs prior to 2012 because of the long lead time needed to make the business decision to build a merchant plant and to design and develop the project. SCE also notes that the large IOUs are unlikely to be in

[28] These parties include AReM, BVES, DRA, IEP, SDG&E, and TURN.

[29] Pursuant to § 399.16(a)(6), RPS-eligible generation from a QF may count for RPS compliance, but may not be the basis of a TREC.

a position to sell RECs to other LSEs prior to attaining the 20% goal. No party disputes these comments.

4.2.2. Distributed Generation

AReM, BVES, PG&E, SCE, and TURN suggest that various forms of distributed generation (DG) may provide some available RECs, though not at a very large scale over the next few years.

There are several types of RPS-eligible DG projects. These include on-site RPS-eligible generation at public water and wastewater facilities; solar photovoltaic (PV) installations, largely constructed under the aegis of the California Solar Initiative (CSI); generation using biodiesel or biogas; and small biomass facilities. [30]

The availability of RECs from such installations has been addressed in a variety of contexts. In D.07-01-018, the Commission determined that owners of DG installations own the RECs associated with the generation, and can therefore sell them, regardless of whether the DG owners participate in net-metering, CSI, or the Self-Generation Incentive Program. In D.07-07-027 and D.08-09-033, implementing § 399.20, the Commission provided for tariffs or standard contracts for utilities' bundled purchase of RPS-eligible generation from DG of not more than 1.5 MW in size located at public water and wastewater facilities and other customers, with an overall statewide limit on such purchases. The

[30] Formal determination of the eligibility of types of generation or particular systems is made by the CEC. The most current statement of CEC guidance is the *Eligibility Guidebook*, (3d ed., December 2007), available at http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-ED3-CMF.PDF.

generation so acquired counts toward the utilities' RPS targets.[31] In this program, customers may sell to the utility either the full output of the DG facility (energy and RECs) or only the excess (energy and RECs) not used for on-site consumption. In the latter case, the RECs associated with the energy used on-site remain with the system owner.

AReM states that the CSI program estimates that the program will have installed about 800 gigawatt hours (GWh) of generation by 2010. AReM additionally estimates that CSI will have provided incentives for approximately 1,100 GWh by 2011. No other party provides quantitative DG estimates.[32]

4.2.2.1. WREGIS Requirements for DG

In order for RECs from any source to be available for RPS compliance, they must be recognized in WREGIS. The requirements for WREGIS are set forth in the WREGIS Operating Rules (June 4, 2007).[33] Several of the rules have implications for the availability of RECs from DG installations for RPS compliance. WREGIS can not register a system smaller than one kilowatt, so some owners of very small DG systems may not be able to participate.[34] Another

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[31] Certain changes have been made to this program by recently enacted SB 380 (Kehoe), Stats. 2008, ch. 544, which amends § 399.20, effective January 1, 2009. None of the changes materially affects the discussion here.

[32] No matter the type of DG generation or the kind of transaction, RECs associated with RPS-eligible DG—like RECs from any other RPS-eligible generation—"shall be counted only once for compliance with the renewables portfolio standard of this state or any other state, or for verifying retail product claims in this state or any other state." (§ 399.16(a)(2).)

[33] The Operating Rules may be found at http://www.wregis.org/content/blogcategory/26/47/.

[34] With respect specifically solar PV installations, the Operating Rules have a new Appendix F, allowing aggregation of rooftop solar installations in certain circumstances.

Footnote continued on next page

WREGIS rule states that RECs cannot be recognized in WREGIS unless the energy associated with the RECs is metered to an accuracy of +/-2%.[35] DG installations that do not provide metering accuracy to that level are not currently eligible for the creation of a REC in WREGIS (called a WREGIS Certificate).[36]

4.2.3. Availability of TRECs

Summarizing this information, it appears that existing RPS-eligible generation is largely already included in utilities' portfolios. Many utility-scale projects are under contract, but not yet built and delivering energy. The construction of new RPS-eligible generation not located in California is uncertain, and the availability of TRECs from that generation is similarly unknown.[37] The use of TRECs from new DG installations is dependent both upon the technical requirements of WREGIS and upon whether the DG owner wishes to retain the RECs to support its own green claims. Since TRECs come

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Appendix F may also be found at http://www.wregis.org/content/blogcategory/26/47/.

[35] Operating Rules, pp. 28-29.

[36] For example, a CSI-subsidized installation taking advantage of the expected performance based buydown (EPBB) program is required to have a meter accurate only to +/-5%. Projects using the CSI performance-based incentives are required to have a meter accurate to +/-2%. Unless the owner of a project with an EPBB incentive voluntarily installs the more accurate (and more expensive) meter, WREGIS would not, under its current rules, allow any RECs to be registered from that facility.

[37] Pub. Res. Code § 25741(b)(2)(B) allows RPS-eligible generation from facilities located outside California to count for RPS compliance provided, among other things, the facility began commercial operation after January 1, 2005.

UCS points out that this fixed date for determining whether a facility is "new" becomes less relevant with each passing year. Nothing in this decision depends on this determination, so we do not address it. We do, however, note that it would be useful to

Footnote continued on next page

from RPS-eligible generation, and the supply of new RPS-eligible generation not already committed to RPS compliance is likely to be limited, the supply of TRECs in the next few years will be similarly limited.

4.3. Guiding Principles

Before, during, and after the TRECs workshop, staff offered several proposals to provide guidance and food for thought to the parties. Because these staff proposals form the basis for many of the parties' suggestions and comments, we briefly review them to provide a background for the rules this decision adopts.

The proposed Guiding Principles distributed in the July 19, 2007 ALJ's Ruling Requesting Pre-Workshop Comments are:

1. Use of REC trading for RPS compliance should be consistent with the legislative goals for the RPS program.
2. REC trading should result in minimal disruption to the current RPS program.
3. REC trading should not increase the cost of RPS compliance in the near term, and should lower the cost of RPS compliance over the longer term.
4. REC trading should promote development of new infrastructure in California and neighboring states for renewable energy generation.
5. REC trading rules, guidelines, and policies should not be inconsistent with the development of a regional REC trading regime.

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have more flexibility in determining when a "new" facility has become an "existing" facility.

6. REC trading rules, guidelines, and policies should take account of the process of implementing California's greenhouse gas (GHG) reduction policy and the potential for regional or federal programs for GHG reduction.

7. REC trading rules, guidelines, and policies should meet the Commission's requirements for REC trading set out in D.03-06-071.

8. REC trading rules, guidelines, and policies should be simple, transparent, easily administered, uniformly applied, and equitable to all LSEs.

Parties largely support or at least accept these guiding principles as laying the groundwork for thinking about a TREC market. Since these principles do not form the basis for this decision and are not part of the rules for the TREC market, it is not necessary to fine-tune them to accommodate all the views expressed by the parties.[38]

4.4. Market Structure and Rules

Drawing on the views of the parties and the ideas in the staff Guiding Principles, it is possible to set some basic goals for the TREC market. It must, at a minimum, enable compliance with California RPS requirements. It should not make RPS compliance more difficult or expensive than it currently is. It should put in place processes that can be used to improve RPS compliance options over time. Beyond compliance, the TREC market should be transparent and able to encourage development of new RPS-eligible generation and maximize the effective use of existing RPS-eligible generation resources. The TREC market should function in a way that protects ratepayers without unnecessarily

[38] We do, however, note IEP's suggestion that the commitment to equity should be applied to all TREC market participants, not simply LSEs.

confining innovation in the market. Finally, the market must allow accountability with respect to RPS flexible compliance rules and reporting and verification.

4.4.1. Staff Straw Proposal

At the TRECS workshop, Energy Division staff presented a "straw proposal" addressing many areas of concern. That proposal was revised and attached to the ALJ's post-workshop ruling for the parties' consideration. Most post-workshop commenters responded to some or all of the points in the Straw Proposal.[39] The Straw Proposal identifies five areas of concern:

- Market participants
- Limits on TREC usage
- Application of flexible compliance rules on banking and earmarking
- Treatment of existing and future bundled RPS contracts
- Utility cost recovery, including bid evaluation, contract review, and price reasonableness.

We turn our consideration to these areas, though not necessarily in the order set out in the Straw Proposal.

4.4.2. Participants

Parties unanimously agree that there should be no restrictions on participation in a TREC market, and that the TREC trading rules should be the same for all participants. This will provide the foundation for a market that is transparent and fair, with the simplest possible rules and the largest range of

[39] For ease of reference, the Straw Proposal is attached as Appendix B. Appendix B does not contain the "rationale" sections provided with the straw proposal attached to the ALJ's ruling.

participants. RPS-obligated LSEs, RPS-eligible generators, California publicly-owned utilities (POUs), parties that aggregate small numbers of RECs into larger packages, financial institutions and other third parties will all be able to contribute to the developing TREC market. Although this decision places no formal restrictions on who can participate in the California TREC market, we note that, as a practical matter, participants must meet the requirements for participation set by WREGIS, through which TREC trades will occur.

4.4.3. Limits on Use of TRECs

In response to direction in SB 107, in D.07-05-028 the Commission established, for a limited period of time, minimum quantities of RPS-eligible energy to be procured through contracts with new facilities[40] or long-term contracts[41] with existing facilities necessary in order for LSEs to count deliveries from short-term contracts with existing facilities for RPS compliance.[42] The Straw Proposal would extend a modified version of these requirements to the use of short-term contracts for TRECs from existing facilities. The Straw Proposal would require that, in order to count short-term TREC contracts with

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[40] Those that entered commercial operation on or after January 1, 2005.

[41] Contracts with durations of 10 years or more.

[42] Section 399.14(b) provides that:

> The commission may authorize a retail seller to enter into a contract of less than 10 years' duration with an eligible renewable energy resource, if the commission has established, for each retail seller, minimum quantities of eligible renewable energy resources to be procured either through contracts of at least 10 years' duration or from new facilities commencing commercial operations on or after January 1, 2005.

At the time D.07-05-028 was issued, this statutory requirement was found in § 399.14(b)(2). Prior § 399.14(b)(1) was repealed by SB 1036 (Perata), Stats. 2007, ch. 685 and the section was renumbered.

existing facilities, an LSE must in the same year sign long-term contracts or contracts with new facilities whose aggregated annual expected deliveries total at least 0.25% of the prior year's retail sales.[43]

Calpine, DRA, PG&E, SCE, and TURN urge that such an extension is justified for the same reasons it is useful for bundled energy contracts. Long-term contracts, they assert, are fundamentally necessary for new development of RPS-eligible generation. The Commission recognized this fact in D.06-10-019, and no party currently disputes it. It therefore makes sense, these parties urge, to apply the same requirements to encourage long-term contracting for TREC contracts.

UCS proposes an additional restriction that short-term TREC transactions with existing facilities can make up no more than 50% of the MWh contracted for in any year by an RPS-obligated LSE. TURN supports this suggestion, arguing that it would reduce the harmful impact on long-term RPS contracting introduced by the use of TRECs.[44]

Most parties, consistent with their views that a nascent TREC market should have few if any regulatory requirements, oppose extension of the minimum quantity requirement. AReM, CEERT, GPI, Horizon, IEP, Mountain Utilities (MU), PacifiCorp and SDG&E all argue that such a requirement would reduce liquidity in the REC market, tend to drive up TREC prices, and make it

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[43] UCS proposes that this figure be 0.75%, rather than 0.25%.

[44] Aglet makes a different type of proposal: that IOUs be allowed to engage in REC-only transactions with other IOUs, but only limited TREC transactions with other LSEs. Aglet does not address third-party market participants. No other party supports this proposal. Because it is inconsistent with the idea of a broad and liquid TRECs market, we do not pursue it further.

more difficult to move to a fully competitive TREC market. PacifiCorp asserts that limits on the use of TRECs will make it more difficult for LSEs to employ the least-cost alternatives in RPS procurement.

CEERT, PG&E, and SCE oppose UCS's suggestion of a more stringent minimum quantity. AReM, PG&E, and SCE oppose UCS' suggestion of a percentage usage limit. PG&E would prefer a minimum quantity requirement like that set forth in D.07-05-028. SCE argues that the UCS position is based on a theoretical concern that the use of TRECs could lead to a reduction in an LSE's commitment to long-term contracts. SCE asserts that, in practice, essentially all parties acknowledge that the supply of TRECs will be quite limited in the near term; the only source of short-term TRECs is likely to be facilities whose existing contracts with IOUs are expiring. Therefore, SCE argues, the kind of limits UCS proposes are simply unnecessary.

While the Legislature required that a minimum quantity requirement be established for bundled contracts, it did not make a similar requirement for TREC contracts. We therefore take a fresh look at the desirability of limits on the use of short-term TREC contracts with existing facilities.

The use of short-term TREC contracts with existing facilities is not, in itself, problematic. As GPI notes, the vast majority of RPS-eligible generation is provided by existing facilities. Short-term TREC contracts, like short-term bundled contracts, may be useful to an RPS-eligible facility at the end of an existing contract and may have only a few years left in its useful life. A short-term contract can allow the facility to continue to produce RPS-eligible energy for the entirety of its productive life. Such a short-term TREC contract can also provide, as essentially all parties note, flexibility for RPS-obligated LSEs in managing their RPS compliance needs.

Problems with the use of short-term TRECs from existing facilities may arise, DRA, TURN, and UCS assert, if LSEs focus on using short-term TRECs to meet their RPS obligations and fail to invest in long-term contracts. As SCE points out, however, this does not seem to be a likely scenario in the near term. Parties agree that essentially all existing RPS-eligible generation in California is either already delivering energy to the large utilities or under contract to them. Moving some RECs associated with that generation from one LSE to another will still leave some or all RPS-obligated LSEs short of the RPS-eligible energy needed to meet the 20% target—thus requiring the development of new RPS-eligible generation.[45]

To the extent that a relatively large number of LSEs may be chasing a relatively small number of short-term TRECs over the next few years, one effect could be elevated TREC prices. But, from the point of view of encouraging new renewable development, relatively high prices for TRECs may be a helpful signal. Such a signal should not, however, harm ratepayers. As set out more fully below, we will set a price cap to protect ratepayers from excessive payments for TRECs in the early years of the TREC market.

The record in this proceeding does not reveal realistic prospects that LSEs will be able to use only short-term TRECs from existing facilities to meet RPS compliance goals in the next three years. Indeed, the parties have largely agreed that a TREC shortage, whether TREC contracts are long-term or short-term, is the most likely state of the market. There is thus no reason to begin the TREC market with artificial restrictions on the nature of TREC procurement for RPS

[45] It is important to remember that RECs associated with RPS-eligible generation from QFs may not be traded, as discussed further in § 4.7 below. See § 399.16(a)(6).

compliance. If later experience shows that some restrictions are warranted, it is always possible for this Commission to exercise its authority to impose conditions on the use of TRECs and adjust the requirements.

As the TREC market matures, it may also be desirable to move away from an approach that focuses on particularized limits, and toward an approach that takes a portfolio approach to the use of TRECs in the RPS program. Parameters such as long-term and short-term, new facilities and existing facilities, TRECs and bundled procurement could be used to develop a more holistic approach to RPS procurement. At this time, however, there is no experience with TRECs that could inform the development of such an approach. We focus now on getting the TREC market off to a good start.

4.4.4. Cost Recovery

The various topics encompassed in the general rubric of cost recovery apply only to the IOUs—large, small, and multi-jurisdictional. The Commission has authority over their rates, and a responsibility to maintain reasonable rates for their ratepayers, while ensuring safe and reliable service and implementing the RPS program goals. This Commission does not have authority over the rates of ESPs or CCAs. Thus, this aspect of REC market and compliance design will not be the same, or even similar, for all RPS-obligated LSEs. This is not a repudiation of the Commission's commitment to equitable treatment of all RPS-obligated LSEs, but simply a reflection of the regulatory reality of the California hybrid energy market.

4.4.4.1. Contract Approval

The large utilities all support the Straw Proposal that contracts for RECs be reviewed in the same way as analogous contracts for bundled energy. No party opposes this fundamental principle; UCS supports aligning the review of short-

term bundled contracts with TREC contracts. SCE specifically requests that TREC contracts be reviewed by the method it proposes in its 2009 RPS procurement plan.

The review processes for bundled contracts and REC contracts should be similar, so far as possible. This promotes the values of administrative simplicity, transparency, and fairness. The development of review processes and price benchmarks for short-term contracts that are either bilateral or the result of a solicitation, and long-term bilateral contracts has been assigned to this proceeding. SCE's initiative with its 2009 procurement plan, however, makes it logical to move the details of the contract approval process to R.08-08-009. We note here that the contract approval processes (for example, submission of an advice letter, or pre-approval subject to the Commission's review of administration of the contracts) should apply both to bundled transactions and REC transactions, though the process for determining price benchmarks will apply only to bundled contracts.

For multi-jurisdictional utilities, the situation is somewhat more nuanced. This Commission does not generally approve their RPS procurement contracts for bundled energy. If, however, a multi-jurisdictional utility wishes to recover costs of a California-specific RPS contract, it must file an advice letter for approval of the costs of the contract. (See D.08-05-029, p. 32.) TREC contracts should be treated similarly. If a multi-jurisdictional utility wishes to recover costs for any quantity of TRECS from a specific contract committed to its California RPS obligations, it must submit an advice letter demonstrating that the levelized price of the RECs does not exceed any price cap or price benchmark applicable to TREC transactions of IOUs, and conforms to any other requirements for TREC cost recovery by multi-jurisdictional utilities.

4.4.4.2. Bid Evaluation

The Straw Proposal suggests that utilities revise their processes for RPS procurement to include requests for offers for REC-only contracts, as well as to revise their least-cost best-fit methodology to allow evaluation of REC-only bids. IEP, PG&E, and TURN generally support this proposal. It would facilitate the integration of REC-only bids into the RPS procurement process. It would also allow direct comparison of bids for bundled energy and bids for REC-only transactions, giving utilities a better way to evaluate the REC-only option. This change in methodology would not require utilities to shortlist any REC-only contracts; rather, it would provide a more complete least-cost best-fit evaluation.

Consideration of improvements to the RPS bid evaluation least-cost best-fit methodology has been identified as one of the tasks in R.08-08-009.[46] TREC-only contracts should be part of that consideration. Therefore, proposals for developing a least-cost best-fit evaluation of REC-only contracts should be addressed in R.08-08-009.

4.4.4.3. TREC Prices

How much is too much for ratepayers to pay for a REC for RPS compliance? Is it possible to control the costs of RECs to utility ratepayers without stunting or distorting the TREC market? These are among the most contentious issues on which parties commented.

The RPS statute allows a utility "to recover the reasonable costs of purchasing renewable energy credits in rates." (§ 399.16(b).) The Straw Proposal suggests that "reasonable costs" should be capped at $35.00 per REC for the cost

[46] See Scoping Memo and Ruling of Assigned Commissioner (September 26, 2008), p. 4.

of RECs used for RPS compliance by RPS-obligated utilities. The cap would be an absolute limit on the price paid for a REC that an IOU uses for RPS compliance; it would not merely be a limit on the amount of the TREC price that could be included in rates.[47]

Some evidence from states with current REC markets, presented at the workshop and discussed in comments, suggests that TREC prices will fall to close to zero (the marginal cost for renewable generation) when demand is low. When demand is high (for example, a compliance deadline looms) TREC prices will rise to the highest allowable cost.[48] TURN and UCS support the applicability of the "boom/bust" analysis to California. AReM, PG&E, SCE, and SDG&E assert that this "boom/bust" cycle is unlikely to occur in California, because RPS flexible compliance rules eliminate the prospect of a single fixed compliance deadline for all RPS-obligated LSEs. Calpine claims that, although banking of RECs and flexible compliance can help, a highly constrained supply of TRECs will have the same effect on prices as an inflexible deadline: prices will rise sharply.

TURN asserts that a price cap is necessary in order to keep REC prices in line with the price of bundled RPS contracts. Ratepayers, TURN argues, should

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[47] This aspect of the Straw Proposal seeks to remove the incentive for a utility to pay any price, however high, that it believes this Commission would allow it to recover in rates; or alternatively, to pay the Commission-allowed amount plus $49.99 (one cent less than the current penalty amount of $50/MWh) for a REC, a scenario identified by SCE in its post-workshop comments. Even if shareholders paid the extra amount, the market price of TRECs could be driven beyond the reach of most RPS-obligated LSEs.

[48] Information on recent TREC prices in markets in other states, provided by Aglet in its supplemental comments, shows that prices vary from a low range (less than $5/REC) through a few in the range of $25/REC, to, in one instance, a high of $48/REC.

not have to pay more for the combination of a REC and conventional energy than they would have paid for a long-term bundled contract for RPS-eligible energy. From this point of view, a REC price cap should set be below the current $50/MWh penalty price because the penalty price plus conventional energy price is currently higher than the long-term bundled RPS contract price. TURN therefore supports the $35 price cap proposal.[49]

Several parties urge that any price cap, if one is adopted at all, be set at the amount of the penalty for noncompliance with RPS procurement obligations.[50] This is currently $50.00/MWh. (See D.03-06-071.) If the price of a TREC bought by an IOU were allowed to exceed the penalty cost, this argument suggests, a utility would have an incentive to pay almost any price for a TREC, (even above the penalty amount) in order to transfer the costs of noncompliance from the shareholders (via a penalty payment) to the ratepayers (via an inflated price for TRECs that would be reflected in rates).

Many parties oppose any cost cap, arguing that price limits almost by definition put artificial restraints on markets.[51] With a new market such as the California TREC market, the argument continues, such early restraints could

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[49] BVES and Central California Power (CCP) also support it. Aglet suggests a more complex calculation that would impose a significantly lower cap, but only on IOU cost recovery for TRECs purchased from unregulated LSEs. Aglet's suggestion is not consistent with an integrated, liquid TREC market, and does not account for the participation of other, non-LSE entities in the TREC market.

[50] GPI and UCS take this position. UCS also expresses a concern that the $35 price cap in the Straw Proposal might be too low in current market conditions to provide incentives for new renewable construction, though the basis for that concern is not clear.

[51] Calpine, CEERT, Horizon, IEP, PG&E, and Solar Alliance take this position.

delay the development of a robust TREC market and stifle the price signals needed to encourage new renewable development.

CEERT urges that, instead of a price cap, the Commission should adopt a price benchmark for TRECs. CEERT argues that a price cap will constrain the TREC market instead of letting market supply and demand determine prices. A reasonableness benchmark, however, would protect ratepayers from unreasonable TREC prices without depressing TREC prices. CEERT suggests that the price benchmark should be set at the penalty amount, rather than at a lower figure, such as the Straw Proposal's $35/REC. CEERT asserts that this would avoid creating a situation in which an IOU could not buy TRECs to fulfill its RPS obligations if they were above the price cap, but below the penalty amount, yet would be subject to the penalty for a procurement shortfall. CEERT does not, however, suggest a methodology for implementing a benchmark to evaluate prices.

A price benchmark for evaluating TREC purchases may be a reasonable proposal for the medium and longer term. In the immediate future (i.e., the next three years), however, it could be difficult to develop a reliable benchmark. TREC prices could not reliably be approximated by, for example, estimating the cost of RPS-eligible energy and subtracting the cost of conventional power, which parties sometimes call the "green premium." Such an RPS energy cost would be extremely difficult to estimate in itself, since RPS power purchase agreements (PPAs) present a wide range of technologies and prices. More importantly, however, TREC prices will be the result of forces in the TREC market, not the energy market. Pressure to comply with the 20% goal combined with a limited supply of TRECs would dominate TREC market pricing, making it

difficult to develop and implement a benchmark using sources other than the TREC market prices.

SDG&E, supported by PG&E, proposes neither a cap nor a benchmark, but a price reasonableness review similar to what is done for all-source procurement. The review would be based on broker quotes, results of solicitations, or a price valuation model. This proposal, however, assumes that there is a fully developed market in which there is a wide range of information. Since, in its early years, the TREC market is unlikely to conform to this model, SDG&E's suggestion, like CEERT's benchmarking suggestion, is premature.

Paradoxically, a published, firm price cap could operate as a reliable price signal for investors in new RPS-eligible generation. At the workshop and in post-workshop comments, staff and parties discussed methods to ensure some measure of price transparency in the early stages of the TREC market. No party proposed any method that would produce public TREC prices. Suggestions were made that some kind of anonymous average of transaction prices could be compiled from data in WREGIS, though how to do this under WREGIS' current functionalities was not clear.

A price cap, by contrast, does not implicate the confidential data of any participant. Market participants may make deals at prices lower than the price cap, and RPS-obligated ESPs and CCAs, as well as POUs, could make deals at higher prices. But the price cap itself could give a reasonable indication of the value of TRECs to ratepayers. As compared to no public indication of price, this would provide important information that could ground new investment in RPS-eligible generation, not simply TREC trades.

In a stable, transparently functioning market, price caps are generally unneeded. The TREC market set up in this decision should, in the longer term,

be such a market. But, as all parties agree, at least in the next three or four years, the demand for TRECs for California RPS compliance is highly likely to exceed the limited foreseeable supply. Many parties—whether in favor of TRECs or skeptical about them—also share the belief that, at least for the next few years, the TREC market will be largely a market for short-term RECs from existing facilities.[52] SDG&E agrees with this position, and extends it by theorizing that the market in short-term RECs from existing facilities "represents, for all intents and purposes, the renewable energy spot market."[53]

Price volatility and high prices are not a necessary outcome of the predicted situation of short TREC supply, but they are a significant risk. We conclude that this is a risk that ratepayers should not be required to bear in the short term. We believe that it is possible to create temporary protections for ratepayers through imposition of a price cap without damaging the basic structure of the TREC market or undermining the financial incentives for new renewable construction that are among the longer-term benefits of a TREC market.

The Straw Proposal's suggestion of price cap of $35/REC, while potentially reasonable, would not be effective. First, as CEERT notes, a utility could have to leave a REC priced at $36 on the table, while paying $50 in penalties for having failed to procure it. Second, as SCE points out, a price cap lower than the penalty amount creates an uneven playing field between utilities and other LSEs. LSEs not subject to the price cap could pay the highest price for

[52] Aglet, Calpine, DRA, IEP, PG&E, TURN, and UCS all make this point.

[53] SDG&E Supplemental Reply Comments, p. 8.

a REC they thought they could afford, up to the penalty amount, thus potentially driving up the price out of reach of utilities.

On the other hand, a price cap of $50/REC is connected to the noncompliance penalty amount. It is the highest economically rational price for a TREC that would not shift the costs of noncompliance from utility shareholders to ratepayers. The penalty structure is, however, intended to put the burden of IOUs' noncompliance with RPS requirements on shareholders, not ratepayers. It would be undermined by allowing utilities to pay more than the penalty amount for TRECs.

Therefore, we adopt a price cap of $50/REC (the penalty amount translated from MWh to RECs). This means that an IOU may not use for RPS compliance a TREC for which it paid more than $50.00, on a levelized basis.[54]

The value of the price cap may be reviewed upon request by any party, at the time of the submission of IOUs' annual RPS procurement plan or (for multi-jurisdictional utilities) integrated resource plan or supplement, beginning with the 2010 RPS procurement plans. Such requests should be made in R.08-08-009 or its successor. Any such request must provide specific justification for revising the price cap. We may also choose to review the cap on our own motion, if appropriate.

The imposition of a price cap, regardless of the value of the price cap as set in this decision or as subsequently revised, will end upon the earlier of these

[54] This does not mean that purchasing TRECs for the amount of the price is per se reasonable. We will evaluate the reasonableness of TREC purchases by utilities in the contract approval process.

events, unless the Commission terminates it at an earlier time or extends it for a longer period:

- All IOUs attain the 20% goal; or
- January 1, 2012.[55]

If there is a new legally binding RPS goal, the price cap may be reviewed in light of the new goal. The assigned Commissioner or assigned ALJ in R.08-08-009 or its successor is authorized to issue any rulings needed to effectuate any review of the $50/REC price cap on TRECs used for RPS compliance by any IOU.

4.5. Cost Limitation Provisions

Section 399.15(d) provides for a limitation on the total above-market costs expended for RPS procurement by IOUs and makes available a limited amount of money to cover above-market costs. It states that "[n]o purchases of renewable energy credits may be eligible for consideration as an above-market cost." (§ 399.15(d)(2)(D).) Thus, TREC purchases are not eligible for any above-market funds set aside pursuant to § 399.15(d)(1). No IOU is required to purchase TRECs to meet RPS obligations if it has otherwise exceeded its cost limitation for bundled contracts (§ 399.16(a)(8)).[56] Because TRECs are equivalent to bundled energy for RPS compliance purposes, IOUs should also have the ability to enter into voluntary TREC transactions even if the cost limitation has been reached, as they do with bundled contracts. (See § 399.15(d)(4).)

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[55] This date is chosen because it is the date binding regulations implementing AB 32 will take effect.

[56] This is analogous to the provision, with respect to bundled contracts, that no IOU is required to purchase bundled electricity at a price above the market price referent if its cost limitation has been exceeded. ((§ 399.15(d)(3).)

4.6. TREC Revenues for the Benefit of Ratepayers

Section 399.16(a)(4) provides that "[a]ll revenues received by an electrical corporation for the sale of a renewable energy credit shall be credited to the benefit of ratepayers." The respondent utilities should promptly take steps to include all TREC transactions in their energy resource recovery accounts (ERRA) or energy cost adjustment (ECAC) accounts, or equivalents, such as power purchase adjustment accounts, as appropriate. Those utilities that believe they do not currently have an appropriate accounting vehicle for TREC transactions should submit advice letters within 60 days of the date of this decision, proposing their accounting treatment of TREC transactions.

4.7. Transactions subject to §§ 399.16(a)(5) and (6)

The RPS statute provides that "no renewable energy credits shall be created" associated with electricity from two types of transactions.[57] The first is a

[57] The relevant parts of § 399.16 are:

> (5) No renewable energy credits shall be created for electricity generated pursuant to any electricity purchase contract with a retail seller or a local publicly owned electric utility executed before January 1, 2005, unless the contract contains explicit terms and conditions specifying the ownership or disposition of those credits. Deliveries under those contracts shall be tracked through the accounting system described in subdivision (b) of Section 399.13 and included in the baseline quantity of eligible renewable energy resources of the purchasing retail seller pursuant to Section 399.15.
>
> (6) No renewable energy credits shall be created for electricity generated under any electricity purchase contract executed after January 1, 2005, pursuant to the federal Public Utility Regulatory Policies Act of 1978 (16 U.S.C. Sec. 2601 et seq.). Deliveries under the electricity purchase contracts shall be tracked through the accounting system described in subdivision (b) of Section 399.12 and count toward the renewables portfolio standard obligations of the purchasing retail seller.

contract executed prior to 2005 that does not specify the ownership of the RECs. The second is a contract executed after January 1, 2005 with a QF.

Because WREGIS tracks renewable generation by issuing RECs (in the form of WREGIS Certificates), it is not possible literally to prevent the creation of RECs from these transactions. It is possible, however, to implement the Legislature's intent by ensuring that the bundled renewable energy from such transactions is tracked through WREGIS and counted toward the RPS obligations of only the purchasing retail seller. LSEs that purchase renewable energy from such transactions can prevent the WREGIS Certificates from being transferred out of their WREGIS accounts (and thus being available for transfer or trading) by setting up appropriate mechanisms within WREGIS to make direct or automatic transfers of the relevant WREGIS Certificates into their WREGIS accounts and retire them for RPS compliance at the earliest feasible time after the WREGIS Certificates are generated.[58] Currently, only the three large utilities have such contracts. We will require them to work with CEC and WREGIS staff to take the necessary steps, if they have not already done so, to move the WREGIS Certificates generated by such transactions as promptly as possible, as determined by the CEC, into their retirement accounts in WREGIS for purposes of RPS compliance.

Energy Division staff should review with CEC staff and the affected utilities whether any changes to the RPS compliance spreadsheet, or other RPS reporting tools, are needed to ensure compliance with §§ 399.16(a)(5) and (6).

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[58] The rules for transfers between accounts in WREGIS are set out in section 15 of the WREGIS Operating Rules.

4.8. Classification of Certain Transactions as REC-Only

The RPS statute requires that RPS-eligible electricity associated with RECs must be "delivered to a retail seller, the Independent System Operator, or a local publicly owned electric utility." (§ 399.16(a)(3).) The statute further allows "delivery" to occur "regardless of whether the electricity is generated at a different time from consumption by a California end-use customer." The CEC may adopt criteria for determining when RPS-eligible energy may be considered "delivered." (Pub. Res. Code §2741(a).)[59] The CEC has done so in its current *Eligibility Guidebook* (pp. 22-36).

The application of the CEC's delivery criteria to RPS transactions has engendered some controversy in this proceeding. The focus of parties' comment is the examples of firming and shaping[60] arrangements for RPS-eligible transactions that are provided in the *Eligibility Guidebook*.[61]

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[59] Pub. Res. Code § 25741(a) provides:

> 'Delivered' and 'delivery' mean the electricity output of an in-state renewable electricity generation facility that is used to serve end-use retail customers located within the state. Subject to verification by the accounting system established by the commission pursuant to subdivision (b) of Section 399.13 of the Public Utilities Code, electricity shall be deemed delivered if it is either generated at a location within the state, or is scheduled for consumption by California end-use retail customers. Subject to criteria adopted by the commission, electricity generated by an eligible renewable energy resource may be considered "delivered" regardless of whether the electricity is generated at a different time from consumption by a California end-use customer.

[60] Firming and shaping are methods of using other generation resources to supplement the delivery of power from the intermittent renewable resources. A fuller explanation is provided in Appendix A of the REC White Paper.

[61] In full, the examples are:

Footnote continued on next page

GPI and UCS each assert in their supplemental comments that this portion of the *Eligibility Guidebook* expands the scope of "delivery" to allow renewable generation that never enters California (whether directly or through conventional firming and shaping arrangements) to count for RPS compliance. They suggest that this will alter the balance of RPS-eligible procurement between facilities located in California and those located in other areas, with an increasing portion of RPS procurement contracts going to facilities located in other states.

TURN argues, following a line of argument made by DRA in protest to some advice letters for RPS contracts,[62] that the CEC has made the requirement of delivery almost meaningless. According to TURN, the negative consequences of the CEC's criteria include sanctioning the delivery of any kind of power, including coal-fired generation, as the "match" for a TREC transaction. TURN also supports the assertions made by GPI and Aglet that allowing TRECs to be so

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1. The facility could provide firming and shaping services. For example, the retail seller could enter into a PPA with an RPS-eligible facility and, as part of the PPA, the facility would provide firming and shaping to deliver a firm or non-firm product into California.

2. A third party could provide firming and shaping services. For example: a retail seller could buy energy and RECs from an RPS-eligible facility and execute a second PPA to resell the energy from the RPS-eligible facility, but not the RECs, to a third party that provides firming and shaping services. Then, the third party could provide the retail seller with a firm schedule for delivery into California.

3. The retail seller could provide firming and shaping services. The retail seller could buy energy and RECs from an RPS-eligible facility, sell the energy back to the facility, and "match" the RECs with energy delivery into California from a second PPA and/or with imports under a pre-existing PPA.

Eligibility Handbook, pp. 23-24, n. 21.

[62] TURN cites to DRA's Protest to PG&E advice Letter 3183-E (January 10, 2008).

unmoored from their underlying associated energy will increase prices by requiring the purchase of replacement energy (since, in the third *Eligibility Guidebook* example, no incremental energy will be delivered into California). TURN argues that this undermines one of the principal values of renewable energy generation—price stability.

The RPS statute makes the CEC the agency responsible for determining RPS eligibility, including the criteria for delivery of electricity. This Commission, however, is authorized to determine whether the use of TRECs should be allowed for RPS compliance, and is empowered to impose any conditions that it determines are reasonable on the use of TRECs.

In the *Eligibility Guidebook*, the CEC makes the disclaimer that its examples of delivery are not intended to "constitute tradable RECs or authorize tradable RECs for RPS compliance." [63] Nevertheless, as TURN accurately perceives, the third, "matching," criterion for delivery describes unbundled REC purchases, not bundled energy deals. In ordinary firming and shaping transactions for bundled energy, the buyer takes delivery of the energy from the generator, or arranges for delivery to the facility providing the firming and shaping services. By contrast, in the "matching" transaction described in the *Eligibility Guidebook*, the buyer takes delivery for only a notional period of time; the energy is essentially instantly sold back to the generator and the buyer has no claim on it. This prevents the buyer from effectuating another feature of shaping and firming transactions, which is the delivery of an incremental quantity of energy to California after the firming or shaping, that is equivalent to the quantity that was

[63] *Eligibility Guidebook*, p. 23, n.21.

generated by the RPS-eligible facility.[64] By contrast, the "matching" criterion (whether with a new or existing PPA) does not result in the delivery of any additional energy to California. The use of a "second PPA and/or imports under a pre-existing PPA" to match the energy sold back to the generator by the RPS-obligated LSE does not necessarily increase the amount of energy delivered to California at all. Thus, this criterion describes a particular form of REC-only transaction that may be used to meet RPS obligations.

This does not mean that such transactions do not meet RPS criteria, or that they should not be allowed. Rather, it is reasonable to classify them as REC-only transactions for purposes of RPS compliance and for purposes of applying the TREC market rules established in this decision. Transactions that really are REC-only should be treated as such, both to protect ratepayers and to ensure orderly and fair administration of the RPS program.

That transactions of this form will be treated as REC-only transactions rather than bundled energy deals does not limit the ability of RPS-obligated LSEs to count them for RPS compliance. As authorized by this decision, and within

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[64] This can be seen from the italicized portions of the first two examples in the *Eligibility Guidebook*:

> 1. The facility could provide firming and shaping services. For example, the retail seller could enter into a power purchase agreement (PPA) with an RPS-eligible facility and, as part of the PPA, t*he facility would provide firming and shaping to deliver a firm or non-firm product into California*.
>
> 2. A third party could provide firming and shaping services. For example: a retail seller could buy energy and RECs from an RPS-eligible facility and execute a second PPA to resell the energy from the RPS-eligible facility, but not the RECs, to a third party that provides firming and shaping services. *Then, the third party could provide the retail seller with a firm schedule for delivery into California*.

the limits specified here, RPS-obligated LSEs may use REC-only transactions to comply with California RPS obligations. Transactions described by the current CEC "matching" scenario meet the delivery requirement as determined by the CEC, that allows use of the RECs so acquired for RPS compliance.

Treating these transactions as the REC-only transactions that they actually are will benefit not only ratepayers, but all California residents. Ratepayers will benefit from the transparency of classifying such deals as REC-only, avoiding unnecessary transaction costs involved in the utility's negotiating and seeking approval for a bundled energy PPA, and in buying and selling back the same energy instantaneously to the generator.[65] However, by calling a TREC a TREC, we ensure that the rules governing the usage of TRECs are equitably applied to all transactions where these rules are appropriate. Without such clarification, transactions with RPS-eligible facilities located in other states, such as those described here, that would otherwise be characterized as REC-only could circumvent these rules by recasting themselves as bundled contracts.

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[65] Among these transaction costs is the potential that such PPAs could contribute disproportionately to credit rating agencies' evaluation of the "debt equivalence" of California utilities. As explained in D.07-12-052, debt equivalence "is a tool used by credit rating agencies to assess potential financial risks associated with a utility's PPA obligations. In certain circumstances, a rating agency may treat some portion of PPA costs as payments on debt obligations rather than as operation costs (treating them as 'debt equivalent'), and in turn make corresponding adjustment to the utility's credit metrics and financial rations uses as part of the rating agency's overall assessment of credit quality." (D. 07-12-052, p. 161.) The PPA's total cost is that of a long-term bundled energy contract, which is significantly higher than the cost of the RECs, which are the net cost of the transaction. If credit rating agencies count the entire face value of the PPA, they may increase the debt equivalence of the utility by more than the actual cash cost of the TREC transaction, thus adding downward pressure on the utility's credit rating.

Properly aligning the incentives to locate renewable generation both in California and in neighboring states will help to increase the use of renewable energy in California and advance the goals of the RPS program, including improving public health and environmental quality, stimulating sustainable economic development, creating new employment opportunities, reducing reliance on imported fuels, and ameliorating air quality problems. (§ 399.16(b), (c).)

We recognize that we have approved a PPA with "matching" arrangements for the RECs.[66] It was presented with the CEC's approval of the delivery structure as part of the advice letter. With the benefit of more extensive party participation through supplemental comments and reply comments in this proceeding, we are now able to determine that, in the exercise of this Commission's authority to impose conditions on the use of RECs for RPS compliance, we should define such transactions as REC-only transactions.

This classification decision applies only to decisions on RPS procurement that are issued by the Commission after the effective date of this decision.

4.9. Compliance and Reporting

As a general principle, the use of TRECs will be consistent with the existing RPS flexible compliance rules.[67] There are a few situations, however, requiring more detailed examination and, in some cases, adjustments.

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[66] Resolution E-4192 (October 2, 2008), available at http://docs.cpuc.ca.gov/PUBLISHED/FINAL_RESOLUTION/91720.htm.

[67] See, e.g., D.06-05-037, D.06-10-050, D.07-02-011; D.08-02-008.

4.9.1. Banking

In the context of bundled energy contracts, RPS-eligible deliveries may be "banked" for an indefinite period for RPS compliance, as allowed by § 399.14(a)(2)(C)(i).[68] That is, an LSE with deliveries in excess of its APT in one year may bank the surplus for use in any later compliance year.

To maintain consistency between the use of unbundled RECs and the use of bundled energy contracts, RECs in excess of an LSE's APT in one year may be banked for use in future years.[69] Because of the nature of RECs and how they are tracked and traded, however, banking of RECs for RPS compliance must be a two-step process: banking in WREGIS and banking within the RPS flexible compliance system. These two steps are the same for RECs associated with bundled contracts and RECs from REC-only contracts.

The first step is banking the REC in WREGIS. Under the WREGIS operating rules, RECs may be maintained indefinitely in a WREGIS participant's "active" account.[70] When RECs are committed to California RPS compliance (or any other compliance purpose), they are transferred to the participant's WREGIS "retirement" account. WREGIS still tracks the RECs in the retirement account, but those RECs may not be traded or used for any other purpose.

Banking within the WREGIS "active" account keeps the RECs available for any purpose. The Straw Proposal would allow "active" banking for up to three

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[68] Section 399.14(a)(2)(C)(i) provides in relevant part that

> The commission shall adopt. . . [f]lexible rules for compliance, including rules permitting retail sellers to apply excess procurement in one year to subsequent years or inadequate procurement in one year to no more than the following three years.

[69] The RECs may be procured through TREC contracts or bundled contracts.

compliance years from the date the WREGIS Certificate is created. That is, an RPS-obligated LSE that wanted to use a REC created in June 2008 for RPS compliance would need to commit the REC to RPS compliance by putting it in its WREGIS retirement account not later than December 31, 2010 (the end of the third compliance year since creation). This is in the mid-range of the banking practices of other states, which typically allow between 18 months and five years for REC banking.[71]

TURN argues that this is too long a period to allow RECs to be held without commitment to RPS compliance, and urges that 18 months is a more appropriate time. UCS supports some limits on banking, in order to ensure that LSEs continue to procure RPS-eligible energy, rather than relying on generation from several years in the past. GPI and Pilot Power Group (PPG) argue that the period of holding RECs in WREGIS should be unlimited, essentially because the banking process for bundled energy is unlimited.

The argument advanced by GPI and PPG conflates the two banking processes. It is possible to allow indefinite banking of RECs for RPS compliance once they have been committed to that purpose, without allowing indefinite holding of TRECs within WREGIS. TURN argues that allowing RECs to sit in WREGIS for an indefinite period of time without being committed to any purpose could encourage hoarding of TRECs and gaming of the REC market by market participants who could buy TRECs and hold them until a major compliance deadline (such as attainment of the 20% target) looms, then sell them

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[70] WREGIS Certificates do not have an expiration date. (Operating Rules, p. 34.)

[71] The staff presentation on "Compliance Rules: Consensus and Unresolved Issues" provided this information at the TREC workshop.

at inflated prices. On the other hand, in order to have a liquid TREC market, it is necessary to keep TRECs available for a long enough period of time that trading within that market will be efficient, while not providing incentives to keep TRECs out of the market.

In evaluating the banking proposals, it is important to remember that the primary purpose of authorizing the use of TRECs is to improve the RPS program. Allowing market participants to hold TRECs indefinitely without committing them to RPS compliance would undermine both liquidity in the market and compliance planning by RPS-obligated LSEs. The Straw Proposal strikes an appropriate balance between maintaining market liquidity and discouraging hoarding of TRECs. The period of three compliance years from REC creation to retirement for RPS compliance will allow an LSE holding RECs to make a good estimate of its future compliance needs, and either commit or sell its RECs. Other TREC market participants will be able to assess their market situations over a reasonable period of time, but without incentives to hold RECs for extremely long periods of time and potentially distort the TREC market.

Once RECs are retired for RPS compliance within WREGIS, they will be captured in the RPS flexible compliance system. They then may be banked according to the flexible compliance rules.

4.9.2. Unbundling of RECs from Future Years of Bundled Contracts

Once a system of tradable RECs is established, any REC recorded in WREGIS are subject to being traded, with the important exception (discussed in § 4.7 above) of RECs associated with the types of contracts described in Pub. Util. Code §§ 399.16(a)(5) and (6). This raises the question of the appropriate

treatment of RECs that are associated with the energy conveyed in bundled RPS contracts.

An LSE with a contract for bundled energy should be able to "unbundle" and sell RECs from that contract on both a spot and a forward basis. In the case of a contract that is delivering energy, TRECs from past deliveries would be tracked in WREGIS and could be sold if they were not yet retired for RPS compliance. TRECs from later deliveries could be sold on a forward basis. In the case of a contract with a facility that is not yet on-line, TRECs could be sold on a forward basis for some or all of the entire term of the contract (with the partial exception of contracts that have been earmarked). Once the RECs are transferred, however, the LSE with the original bundled contract may not use *either* the REC *or* the underlying energy for RPS compliance; the RPS compliance value has been transferred to the purchaser with the REC.[72]

The potential unbundling and sale of RECs from bundled contracts that have been earmarked to make up shortfalls from prior years presents a special case.[73] The Straw Proposal suggests that RPS-obligated LSEs should not be allowed to unbundle the RECs from the first year of such contracts, since that year's deliveries have already been committed to make up a prior year's shortfall

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[72] Energy Division staff should review the RPS compliance spreadsheet and reporting rules to determine whether additional reporting requirements should be imposed to track these transactions.

[73] "Eearmarking" is a flexible compliance mechanism by which deliveries from a future RPS procurement contract may be designated to make up, within three years, shortfalls in RPS procurement in the same year in which the earmarked contract was signed. As part of the earmarking process, Energy Division staff reviews the contract proposed for earmarking to ascertain whether the contract is likely to deliver as proposed, since it is covering an already-incurred shortfall.

under the flexible compliance rules. This raises the risk of double-counting the unbundled RECs, as earmarked by one LSE and retired for RPS compliance by another. On the other hand, if an earmarked contract turns out not to be needed to make up the shortfall for which it has been earmarked, the RECs should be able to be unbundled. We adopt an approach that would encourage liquidity in the TREC market without undermining the flexible compliance rules. An LSE should be prohibited from earmarking any bundled contract from which any RECs generated in the first three years of deliveries under the contract are unbundled and traded.

4.9.3. Earmarking of TREC Contracts

In the Straw Proposal, staff suggests that earmarking of TREC contracts not be allowed. CEERT, GPI, IEP, PG&E, and UCS agree with this position. AReM, Pilot Power, SCE, and SDG&E argue against it. The opponents assert that all RPS contracts should be treated equally. They asset that administrative difficulty in making a viability determination should not prevent earmarking of TREC contracts. SCE asserts that TRECs from new facilities would be discouraged if earmarking of TRECs were not allowed.

Although in almost all respects TRECs can and should fit into the flexible compliance rules, adding REC-only contracts into the earmarking process would not be appropriate. For TREC purchases that are associated with energy from more than one generator, staff would have significant difficulty undertaking an adequate review of potential future performance under the contract, since access to confidential information about the viability of the underlying generation projects may be hard to find. This increases the risk that the earmarked shortfall will not in fact be made up within the required three-year period. There is no reason to believe that the inability to earmark TREC contracts will discourage

LSEs from entering into them, if the TRECs are otherwise offered at a reasonable price and in a time frame that meets the LSE's RPS compliance needs.

4.9.4. Reporting

The RPS reporting structure has been set forth in D.06-10-050.[74] Energy Division staff has developed a collaborative process with parties in which any changes needed in the reporting formats are developed and reviewed.[75] Staff should use this process to make revisions to current reporting formats that may be needed to accommodate the use of TRECs. The assigned Commissioner and assigned ALJ in R.08-08-009 or its successor may issue any rulings necessary to provide staff and the parties with the opportunity to develop revisions to the reporting formats.

Following a suggestion made by CEERT, all RPS-obligated LSEs should be required to file with Energy Division reports on TREC purchases, sales, and prices, with appropriate confidentiality protections. This will enable staff to monitor developments in the TREC market and could provide warning of problems that should be addressed by this Commission. Energy Division has discretion to develop, in consultation with the parties, the format and timing of such reports

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[74] A standardized RPS reporting format and a process for considering changes to the reporting format were adopted in R.06-05-027 by an ALJ's Ruling Adopting Standardized Reporting Format, Setting Schedule For Filing Updated Reports, and Addressing Subsequent Process (March 12, 2007).

[75] Reporting formats include the semiannual compliance spreadsheets and any other documentation needed to report on RPS compliance.

One special situation should be noted here. If an RPS-obligated LSE enters into a REC-only transaction of the "matching" form discussed in § 4.8, above, staff must be able to verify how it should be characterized. For utilities that must submit their contracts via advice letter, that step is provided. But RPS procurement contracts of CCAs, ESPs, and multi-jurisdictional utilities do not require Commission approval. Those LSEs must submit a copy of such contracts to Energy Division and specifically identify their use in their most contemporaneous RPS compliance report.

4.10. Standard Terms and Conditions

Parties commenting on this issue favor minimal new STCs for TREC contracts, and little or no change to the STCs for bundled RPS contracts.[76] Parties unanimously believe that an STC defining RECs is the core, and perhaps only, STC needed. SDG&E adds that the STC must provide that the RECs are tracked in WREGIS; PG&E and AReM include a "CPUC approval" term.

We agree with the parties that few changes to STCs are required. It is clear that all TREC contracts will need an STC that ensures that the RECs being transferred conform to the definition and attributes of RECs set forth in D.08-08-028, or any later modifications made by decision of this Commission or new legislation. Because RECs can not recognized for RPS compliance unless they are tracked in WREGIS, TREC contracts must contain assurances that the

[76] AReM, CEERT, PG&E, SCE, SDG&E, and UCS made suggestions for STCs.

buyer or seller, as appropriate, has taken all steps necessary to ensure that the generation is properly registered and the RECs will be tracked in WREGIS.[77]

In addition, as PG&E points out, TREC contracts of both large and small IOUs must include the same requirement as bundled contracts that the contract takes effect upon approval by this Commission.[78]

Defining and tracking RECs and requiring this Commission's approval of contracts where that approval is necessary cover the minimum requirements for STCs related to the use of TRECs for RPS compliance. Therefore, only three STCs will be required for REC-only contracts: REC definition, WREGIS tracking, and Commission approval for utility contracts (other than multi-jurisdictional utilities).

Bundled contracts transfer RECs as well as energy. In order for bundled contracts to be consistent with REC-only contracts and to allow the unbundling and trading of RECs from bundled contracts as authorized by this decision, the RECs definition and WREGIS tracking STCs should be added to the STCs for bundled contracts.

The two new REC STCs address the fundamental issues of what is being conveyed by the contract. They should be non-modifiable in both REC-only and bundled contracts. The STC requiring Commission approval for REC-only contracts should likewise by non-modifiable in REC-only contracts, as it is in bundled contracts. The new STCs are set out in Appendix C.

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[77] Because WREGIS allows LSEs to register in WREGIS on behalf of small generators, in some cases the buyer rather than the seller will need to provide assurance of WREGIS registration.

4.11. Coordination with GHG Accounting

In D.08-08-028, the Commission took note of a hypothetical situation raised by some parties, in which a California RPS-obligated LSE would acquire unbundled RECs from an RPS-eligible generator in a jurisdiction that does not have a cap on GHG emissions, without the delivery of any associated energy to California.[79] In the supplemental comment ruling, the ALJ asked parties for their views on whether the Commission should provide further recommendations on this issue to the California Air Resources Board. The majority of commenters, including PG&E, SDG&E, and UCS state that this decision, which focuses on the new TRECs market we authorize, is not the appropriate place to pursue this complex and technical GHG issue. SCE is the principal proponent of addressing this issue now.

In D.08-10-037, closing the current GHG proceeding, the Commission noted that the posited scenario could not currently occur, since § 399.16(a)(3) requires that the energy associated with an unbundled REC be delivered to California. D.08-10-037 stated that, if that requirement were to change, "the appropriate treatment of unbundled RECs from electricity generated in an uncapped state and not delivered to the California grid may require further consideration." (D.08-10-037, p. 98.) This issue will therefore not be addressed in this decision.

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[78] This Commission does not approve RPS contracts of multi-jurisdictional utilities. See § 4.4.4.1, above.

[79] D.08-08-028, p. 27, n.59.

4.12. Next Steps

The final revised joint staff report on WREGIS required by § 399.16(a)(1) was released with a draft resolution on September 23, 2008. After public comment on the draft resolution and any necessary revisions to the joint staff report, both agencies will adopt the identical final Report. This Commission will do so by resolution; the CEC will adopt the Report at one of its business meetings. Once the joint staff report is adopted, the final statutory precondition for authorizing the use of TRECs for RPS compliance will be satisfied.

Refining the least-cost best-fit (LCBF) bid evaluation process to allow TREC contract bids to be evaluated side by side with bids for bundled contracts in utility RPS procurement processes will encourage integration of REC-only and bundled procurement decision-making. Developing processes for the Commission's approval of contracts that work for both types of procurement will also aid in that integration. These tasks are most appropriately undertaken in R.08-08-009, where all aspects of the RPS procurement process are addressed. One task in the current proceeding—developing price benchmarks for evaluating price reasonableness of short-term RPS bundled contracts and long-term bilateral bundled contracts—does not apply to REC-only transactions. Because it is closely linked with other contract evaluation issues, however, it too should be considered in R.08-08-009. The assigned Commissioner is authorized to revise the scoping memo for R.08-08-009 to include these three tasks (LCBF, contract approval, and price benchmarks) in that proceeding.

We will work with the CEC to improve the treatment of the RPS delivery requirements in the upcoming revision of the CEC's *RPS Eligibility Guidebook*.

We also must consider the possibility that we could need to revisit some aspects of this decision in the future. The landscape within which our RPS

program functions is always changing, but some possibilities are already visible. Our state may increase its RPS goals to 33% of retail sales by 2020. The full implementation of AB 32 may lead to other changes as well. Review of how the TREC market is functioning may reveal unexpected challenges or opportunities not fully encompassed in this decision.

5. Comments on Proposed Decision

The proposed decision of ALJ Simon in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on _____, and reply comments were filed on _____ by _____.

6. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Anne E. Simon and Burton W. Mattson are the assigned ALJs for this proceeding.

Findings of Fact

1. Allowing the use of TRECs for RPS compliance will give RPS-obligated LSEs increased options for RPS compliance.

2. The use of TRECs for RPS compliance will be compatible with existing RPS flexible compliance rules.

3. As the California TREC market develops, it is likely to provide support for the development of new RPS-eligible generation.

4. In view of the benefits of the use of TRECs for RPS compliance and the development of a viable TREC market, it is reasonable to allow the use of TRECs for RPS compliance, subject to reasonable conditions.

5. In the early years of a California TREC market, prior to LSEs' attaining the goal of 20% of retail sales from RPS-eligible generation resources, demand for TRECs is likely to exceed supply.

6. In the early years of a California TREC market, it is reasonable to protect ratepayers from the potential for volatility and high spikes in TREC prices.

7. In order to provide temporary protections for ratepayers without damaging the basic structure of the TREC market or undermining the financial incentives for new renewable construction that are among the longer-term benefits of a TREC market, it is reasonable to impose a reviewable price cap of $50/REC for TREC purchases by IOUs.

8. Since RPS-obligated LSEs are likely to need other sources in addition to the available TRECs in order to meet their RPS compliance obligations, it is not necessary to impose preconditions on the use of TRECs for RPS compliance other than those required by the RPS statute.

9. In order to promote liquidity in the TREC market, it is reasonable to impose a limit on the period of time that TRECs used for RPS compliance may be held in an "active" WREGIS account before being retired for RPS compliance.

10. In order to promote liquidity in the TREC market and provide RPS compliance flexibility, it is reasonable to allow LSEs to unbundle and sell RECs from bundled contracts for RPS-eligible energy, on both a spot and forward basis.

11. In order to preserve the Commission's ability to determine compliance with RPS obligations and to eliminate the potential for double-counting of some RECs, it is reasonable to prohibit the earmarking of any bundled RPS contract from which RECs have been unbundled and traded from the first three years of anticipated or actual deliveries.

12. Because it is not possible for the viability of REC-only contracts to be assessed in the same way as bundled contracts, it is reasonable to prohibit the earmarking of REC-only contracts.

13. In view of the uncertainties involved in the early years of a new TREC market, it is reasonable to provide for regular assessments of market performance by Energy Division staff and, as needed, review of the market rules set forth in this order.

Conclusions of Law

1. The use of TRECs for RPS compliance should be authorized.

2. Trading of RECs that meet the requirements of D.08-08-028 and any subsequent Commission decision, or any applicable legislation, characterizing RECs should begin not earlier than January 1, 2009.

3. Only TRECs properly tracked in WREGIS should be allowed to be used for RPS compliance.

4. Existing RPS flexible compliance rules should be applied to the use of TRECs for RPS compliance, with the following adjustments needed to account for differences between REC-only transactions and bundled transactions, or for special characteristics of REC-only transactions:

   a. REC-only contracts may not be earmarked;

   b. Bundled contracts from which RECs have been unbundled in the first three years may not be earmarked.

5. RECs associated with RPS-eligible generation under contracts signed prior to 2005 that do not allocate ownership of RECs and contracts with QFs signed after January 1, 2005 may not be unbundled or used for RPS compliance separate from the associated energy.

6. In order to allow flexibility in RPS procurement and compliance, IOUs should be able to enter into voluntary TREC transactions even if their cost limitation, as set out in § 399.15(d), has been reached.

7. In order to promote consistency in RPS procurement and protect ratepayers from excessive costs, so long as the CEC accepts as RPS-eligible those transactions with RPS-eligible generation facilities that are not sited in California and do not have their first point of interconnection with the WECC grid in California, in which the RPS-obligated LSE buys RECs and energy from the RPS-eligible facility, sells the energy back to the generation facility, and then "matches" the RECs for RPS compliance purposes with energy delivered into California from a second power purchase agreement PPA and/or with imports under a pre-existing PPA, such transactions should be treated as REC-only transactions for purposes of RPS compliance.

8. A cap on the price a utility may pay for TRECs should be imposed; the price cap should not be treated as a per se reasonable price for a TREC.

9. IOUs should include proceeds of the sale of TRECs in their ERRA or ECAC accounts, or equivalents (such as power purchase accounts) for the benefit of ratepayers. Any IOU not currently having an appropriate accounting method should file an advice letter within 60 days of the date of this decision proposing an accounting method.

10. In order to allow multi-jurisdictional utilities to recover the reasonable costs of REC-only contracts for California RPS compliance, such contracts should be submitted for Commission approval via advice letter.

11. In order to facilitate the integration of REC-only transactions into the RPS flexible compliance rules, the Director of Energy Division should be authorized to make revisions to the RPS compliance spreadsheet and other RPS reporting

formats to implement the requirements and conditions set forth in this order. Such revisions should include but not be limited to reports on TREC purchases, sales, and prices.

12. In order to allow the use of unbundled RECs for RPS compliance as soon as practicable, this order should be effective immediately.

O R D E R

IT IS ORDERED that:

1. Renewable energy credits (RECs) that are procured unbundled from the energy eligible for the renewables portfolio standard (RPS) with which they are associated may be used for RPS compliance.

2. Unbundled RECs may be traded in accordance with the rules set out in this decision.

3. Trading of RECs in accordance with the rules set out in this decision may commence not earlier than January 1, 2009.

4. Only RECs properly tracked and retired in the Western Renewable Energy Generation System (WREGIS) shall be used for RPS compliance.

5. Any RECs properly tracked in WREGIS that conform to the requirements of Decision (D.) 08-08-028 and any subsequent Commission decision or any applicable legislation characterizing RECs may be used for RPS compliance, subject to the restrictions in Ordering Paragraphs 6 and 7, below.

6. RECs associated with RPS-eligible energy delivered under procurement contracts signed prior to 2005 that do not allocate ownership of the RECs shall be used for RPS compliance only if they are not transferred to an entity other than the generator or original buyer in WREGIS prior to being retired for RPS compliance.

7. RECs associated with RPS-eligible energy delivered under procurement contracts with qualifying facilities signed after January 1, 2005 shall be used for RPS compliance only if they are not transferred to an entity other than the generator or original buyer in WREGIS prior to being retired for RPS compliance.

8. RECs that are used for RPS compliance may be held in "active" accounts in WREGIS for no more than three compliance years (inclusive of the year in which the RECs are created) from the date they are created before being retired in WREGIS for use for RPS compliance.

9. Once RECs are retired in WREGIS for use for RPS compliance, they may be banked for use in future years in accordance with the RPS flexible compliance rules.

10. The RECs from bundled contracts currently delivering RPS-eligible energy may be unbundled and traded separately from the associated energy, so long as, once the RECs have been sold, the associated energy is not used for RPS compliance.

11. The RECs from bundled contracts scheduled to deliver RPS-eligible energy in the future may be unbundled and traded on a forward basis separately from the associated energy, so long as, once the RECs are generated, they are properly tracked in WREGIS and, once the RECs have been sold, the associated energy is not used for RPS compliance.

12. Any bundled contract from which any RECs generated in the first three years of deliveries under the contract are unbundled and traded may not be earmarked to apply to a shortfall in meeting an RPS-obligated load-serving entity's (LSEs) annual procurement target in the year the contract was signed.

13. Contracts for REC-only transactions may not be earmarked to apply to a shortfall in meeting an RPS-obligated LSE's annual procurement target.

14. No RECs for which the levelized amount paid is greater than $50.00 per REC may be used for RPS compliance by any investor-owned utility (IOU).

15. So long as the California Energy Commission accepts as RPS-eligible those transactions with RPS-eligible generation facilities that are not sited in California and do not have their first point of interconnection with the Western Electricity Coordinating Council grid in California in which the RPS-obligated LSE buys RECs and energy from the RPS-eligible facility, sells the energy back to the generation facility, and then "matches" the RECs for RPS compliance purposes with energy delivered into California from a second power purchase agreement (PPA) and/or with imports under a pre-existing PPA, any such transactions which have not been approved by this Commission prior to the effective date of this decision shall be treated as REC-only transactions for purposes of RPS compliance.

16. Investor-owned utilities (IOUs) that have reached the RPS procurement cost limitation set forth in § 399.15(d) may enter into voluntary TREC transactions.

17. REC-only contracts of IOUs may be reviewed by the Director of Energy Division in the same manner and according to the same procedures as the RPS procurement contracts of analogous type and length.

18. IOUs shall promptly set up an appropriate accounting method to apply proceeds of the sale of RECs for the benefit of ratepayers. Any IOU not currently having an appropriate accounting method shall file an advice letter within 60 days of the date of this decision proposing an accounting method.

19. Any REC-only contracts for which a multi-jurisdictional utility seeks recovery of costs must be submitted via advice letter.

20. The Director of Energy Division is authorized to review existing RPS reporting formats and tools and undertake appropriate revisions to allow complete reporting and monitoring of the provisions in this order.

21. The Director of Energy Division may require the submission of appropriate documentation to verify compliance with any of the requirements set forth above.

22. The assigned Commissioner or assigned administrative law judge in Rulemaking (R.) 08-08-009 or its successor is authorized to:

a. Upon motion of any party made at the time that utilities submit their annual RPS procurement plans, initiate a review of the REC price cap.

b. Issue any rulings necessary to facilitate revision of the RPS reporting methods to accommodate the use of unbundled and tradable RECs for RPS compliance.

23. Three related issues identified in this proceeding shall be addressed in R.08-08-009:

a.. The revision of utilities' least-cost best-fit methodologies to include evaluation of REC-only contracts.

b. The process of approval of utilities' bundled energy and REC-only short-term contracts (whether bilateral or the result of solicitations) and long-term bilateral contracts.

c. The development of price benchmarks for evaluating the reasonableness of utilities' short-term bundled contracts (whether bilateral or the result of solicitations) and long-term bilateral bundled contracts.

24. R. 06-02-012 is closed.

This order is effective today.

Dated _____, at San Francisco, California.

APPENDIX A

§ 399.16. Use of renewable energy credits to satisfy the requirements of the renewables portfolio standard

(a) The commission, by rule, may authorize the use of renewable energy credits to satisfy the requirements of the renewables portfolio standard established pursuant to this article, subject to the following conditions:

(1) Prior to authorizing any renewable energy credit to be used toward satisfying annual procurement targets, the commission and the Energy Commission shall conclude that the tracking system established pursuant to subdivision (c) of Section 399.13, is operational, is capable of independently verifying the electricity generated by an eligible renewable energy resource and delivered to the retail seller, and can ensure that renewable energy credits shall not be double counted by any seller of electricity within the service territory of the Western Electricity Coordinating Council (WECC).

(2) A renewable energy credit shall be counted only once for compliance with the renewables portfolio standard of this state or any other state, or for verifying retail product claims in this state or any other state.

(3) The electricity is delivered to a retail seller, the Independent System Operator, or a local publicly owned electric utility.

(4) All revenues received by an electrical corporation for the sale of a renewable energy credit shall be credited to the benefit of ratepayers.

(5) No renewable energy credits shall be created for electricity generated pursuant to any electricity purchase contract with a retail seller or a local publicly owned electric utility executed before January 1, 2005, unless the contract contains explicit terms and conditions specifying the ownership or disposition of those credits. Deliveries under those contracts shall be tracked through the accounting system described in subdivision (b) of Section 399.13 and included in the baseline quantity of eligible renewable energy resources of the purchasing retail seller pursuant to Section 399.15.

(6) No renewable energy credits shall be created for electricity generated under any electricity purchase contract executed after January 1, 2005, pursuant to the

federal Public Utility Regulatory Policies Act of 1978 (16 U.S.C. Sec. 2601 et seq.). Deliveries under the electricity purchase contracts shall be tracked through the accounting system described in subdivision (b) of Section 399.12 and count toward the renewables portfolio standard obligations of the purchasing retail seller.

(7) The commission may limit the quantity of renewable energy credits that may be procured unbundled from electricity generation by any retail seller, to meet the requirements of this article.

(8) No electrical corporation shall be obligated to procure renewable energy credits to satisfy the requirements of this article in the event that the total costs expended above the applicable market prices for the procurement of eligible renewable energy resources exceeds the cost limitation established pursuant to subdivision (d) of Section 399.15.

(9) Any additional condition that the commission determines is reasonable.

(b) The commission shall allow an electrical corporation to recover the reasonable costs of purchasing renewable energy credits in rates.

(END OF APPENDIX A)

APPENDIX B

STAFF STRAW PROPOSAL

COMPLIANCE QUESTIONS	STRAW PROPOSAL
Market Participants	
• Who can participate in the California compliance REC market?	There are no limits on market participation.
• Should the REC trading rules differ for third parties (any non RPS-obligated entity)?	To the greatest extent possible, rules should be consistent for all participants.
TREC Usage Limits	
• Pursuant to Pub. Util. Code § 399.16(a)(7), the Commission may limit the quantity of tradable RECs (TRECs) procured for RPS compliance.	To address usage limits, a minimum quota mechanism, similar to the one set forth in D.07-05-028 for short term contracts, will be applied to TRECs.
• Should there be a limit on the quantity of tradable RECs that can be used by LSEs for RPS compliance? Should the limit be different for different classes of LSEs?	The minimum quota will allow, in any calendar year, LSEs to count short-term REC contracts for RPS compliance only if, in the same calendar year, the LSE signs long-term bundled contracts or bundled contracts with new facilities whose aggregated annual expected deliveries[1] total at least 0.25% of its prior year's retail sales.

[1] This is different from the minimum quota framework set forth in D.07-05-028, which requires that the *total* deliveries expected from the long-term contracts and contracts with new facilities are greater than 0.25% of prior year's retail sales before short-term contracts can be signed.

Flexible Compliance: Banking

• Should tradable RECs have an "expiration date"?

• Should RPS-obligated LSEs be able to "bank" tradable RECs without limitation as to quantity?

• Should RPS-obligated LSEs be able to "bank" tradable RECs without temporal limitations?

Note: Currently, there are no temporal or quantity restrictions for banking bundled RPS contracts. Flexible compliance is tracked for each LSE in its Reporting and Compliance Spreadsheet submitted in biannual performance reports required by D.06-10-050.

Banking within WREGIS

In order for tradable RECs to be used for RPS compliance, they must be retired[2] in WREGIS within three compliance years (including compliance year in which it was generated).[3]

Banking after WREGIS

After RECs are retired in WREGIS, they can be banked indefinitely for RPS compliance purposes.

The flexible compliance for RECs and RPS bundled procurement will be tracked by the Compliance Spreadsheets submitted as part of the biannual Compliance Reports (D.06-10-050).

[2] "A Retirement Subaccount is used as a repository for WREGIS Certificates that the Account Holder wants to designate as Retired and remove from circulation (e.g. to demonstrate compliance with a state's RPS). Once a Certificate has been transferred into a WREGIS Retirement Subaccount, it cannot be transferred again to any other Account." (WREGIS Operating Rules, p. 6)

[3] The LSEs should create a banking Active sub-account within WREGIS to 'hold' RECs until they are retired for compliance purposes.

Flexible Compliance: Earmarking	
• Should earmarking[4] be allowed for TRECs?	No tradable RECs can be used for earmarking. No forward REC contracts can be used for earmarking.
Treatment of Bundled[5] Contracts	
• What types of existing and future bundled RPS contracts can be unbundled for REC trading (excluding contracts pursuant to Pub. Util. Code § 399.16(a) for which no RECs will be created)?	Beginning on January 1, 2009, LSEs can unbundle and sell the RECs (that are tracked in WREGIS) from currently operational RPS projects. (Once the RECs are sold, they cannot be used for RPS compliance by the selling LSE. The null power also cannot be used for RPS compliance by any LSE.) Beginning on January 1, 2009, LSEs can unbundle and sell RECs (that are tracked in WREGIS), on a forward basis, from Commission-approved RPS projects that are not yet online. (Once the RECs are sold, they cannot be used for RPS compliance by the selling LSE. The null power also can not be used for RPS compliance.)

[4] Earmarking is a flexible compliance tool that LSEs can conditionally use to defer deficits. See D.06-10-050, Attachment A, pages 9-10.

[5] A bundled RPS contract is a power purchase agreement that conveys all energy, capacity and environmental attributes to a load-serving entity.

	However, LSEs cannot unbundle the first year of a bundled contract if it has been set aside for RPS earmarking. - LSEs can unbundle subsequent years of an earmarked bundled contract
Cost Recovery	
• What is the review and approval process for IOU REC contracts? *(Currently, all IOU bundled RPS contracts must be filed by advice letter. The contract review process for short-term bundled contracts is being separately developed in R.06-02-012.)* • What price evaluation mechanism should the Commission use to evaluate whether a REC contract price is reasonable? • Should the Commission establish standard terms and conditions (modifiable and/or non-modifiable) to be contained in REC contracts?	<u>Review process:</u> Long-term REC contracts (either from a solicitation or bilateral) must be filed with the Commission by advice letter. All short-term REC contracts should follow the same approval process that is established in R.06-02-012 for short-term bundled contracts. <u>Price evaluation criteria:</u> IOUs should solicit REC contracts in their annual renewable RFOs. As part of this process, the IOUs must modify their least cost, best fit (LCBF) evaluation methodologies to shortlist the most competitive REC contracts. The LCBF methodology should compare the benefits and costs of bundled contracts with REC transactions and evaluate them relative to the LSE's entire RPS portfolio. A price cap will also be used to protect ratepayers from unreasonable costs. The price cap

for any REC contract (short term, long term, bid into a solicitation, bilateral) is $35/REC levelized using the IOU's approved discount rate.

Bilateral REC contracts are allowed also and are subject to the $35/REC levelized price cap.

Standard terms and conditions:

Each REC contract must contain a Commission-approved term identifying the RECs and their attributes transferred to the buyer. This term is not modifiable.

(END OF APPENDIX B)

APPENDIX C

NEW AND REVISED STANDARD TERMS AND CONDITIONS

STC REC-1 Transfer of renewable energy credits (Applies to all REC-only and bundled contracts)

Non-modifiable

Seller warrants that the renewable energy credits transferred to Buyer conform to the definition and attributes required for compliance with the California Renewables Portfolio Standard, as set forth in California Public Utilities Commission Decision 08-08-028, and as may be modified by subsequent decision of the California Public Utilities Commission or by subsequent legislation.

STC REC-2 Tracking of RECs in WREGIS (Applies to all REC-only and bundled contracts) Non-modifiable

Seller [or Buyer; choose appropriate party] warrants that all necessary steps have been taken to allow the renewable energy credits transferred to Buyer to be tracked in the Western Renewable Energy Generation Information System.

STC REC-3 CPUC Approval (Applies to REC-only contracts of regulated utilities other than multi-jurisdictional utilities)

Non-Modifiable

"CPUC Approval" means a final and non-appealable order of the CPUC, without conditions or modifications unacceptable to the Parties, or either of them, which contains the following terms:

(a) approves this Agreement in its entirety, including payments to be made by the Buyer, subject to CPUC review of the Buyer's administration of the Agreement; and

(b) finds that any procurement pursuant to this Agreement is procurement of renewable energy credits that conform to the definition and attributes required for compliance with the California Renewables Portfolio Standard, as set forth in California Public Utilities Commission Decision 08-08-028, and as may be modified by subsequent decision of the California Public Utilities Commission or by subsequent legislation, for purposes of determining Buyer's compliance with any obligation that it may have to procure eligible renewable energy resources pursuant to the California Renewables Portfolio Standard (Public Utilities Code Section 399.11 *et seq.*), Decision 03-06-071, or other applicable law.

CPUC Approval will be deemed to have occurred on the date that a CPUC decision containing such findings becomes final and non-appealable.

(END OF APPENDIX C)

INFORMATION REGARDING SERVICE

I have provided notification of filing to the electronic mail addresses on the attached service list.

Upon confirmation of this document's acceptance for filing, I will cause a Notice of Availability of the filed document to be served upon the service list to this proceeding by U.S. mail. The service list I will use to serve the Notice of Availability of the filed document is current as of today's date.

Dated October 29, 2008, at San Francisco, California.

/s/ FANNIE SID
Fannie Sid