Decision **PROPOSED DECISION OF ALJ MATTSON** (Mailed 8/24/2010)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	Rulemaking 08-08-009 (Filed August 21, 2008)

DECISION ADOPTING THE RENEWABLE AUCTION MECHANISM

TABLE OF CONTENTS

Title **Page**

TABLE OF CONTENTS
(Cont'd)

Title **Page**

TABLE OF CONTENTS
(Cont'd)

Title **Page**

TABLE OF CONTENTS
(Cont'd)

Title **Page**

TABLE OF CONTENTS
(Cont'd)

Title **Page**

TABLE OF CONTENTS
(Cont'd)

Title **Page**

TABLE OF CONTENTS
(Cont'd)

Title **Page**

DECISION ADOPTING THE RENEWABLE AUCTION MECHANISM

1. Summary

~~We ordered the use of tariffs and standard contracts in July 2007 for some transactions up to 1.5 megawatts (MW) within~~

This decision authorizes a new procurement process called the Renewable Auction Mechanism, or RAM, for the procurement of smaller renewable energy projects that are eligible for the California Renewables Portfolio Standard (RPS) Program. ~~We provided for further study of limited issues to complete implementation of this part of the RPS Program. We resolved the first limited issue in September 2008.~~

~~We address the remaining issues today in part. The result is that we adopt a new procurement protocol that we call the Renewable Auction Mechanism, or RAM, for transactions up to 20 MW. RAM employs standardized contracts and applies to the three largest investor-owned utilities up to a program total of 1,000 MW. Individual prices are determined by each seller submitting a non-negotiable bid, with buyers selecting purchases in the order of least-costly first. We summarize the adopted program in Appendix A. This proceeding remains open.~~ The RAM is a simplified and market-based procurement mechanism for large investor-owned utilities (IOU). The Commission adopts RAM as a primary contracting tool for this market segment because doing so will promote competition and elicit the lowest costs for ratepayers, encourage the development of resources that can utilize existing transmission and distribution infrastructure, and contribute to RPS goals in the near term. We expect RAM to complement the RPS Program by reducing transaction costs and providing a

procurement opportunity for smaller RPS-eligible projects, which have not been able to effectively participate in the annual RPS solicitations to date.

RAM evolved from the Commission's inquiry into expanding the existing feed-in tariff program for generators 1.5 MW and below, pursuant to Public Utilities Code Section 399.20 and Decision (D.)07-07-027. However, RAM is distinct from a feed-in tariff as that term has traditionally been used. While it is a streamlined contracting mechanism and utilizes a standard contract, RAM relies on market-based pricing, utilizes project viability screens, and selects projects based on least cost rather than on a first-come first-served basis at an administratively determined price.

The rules adopted for RAM in this decision are intended to reduce transaction costs, promote regulatory certainty, and provide value to the market, utility, regulator, and ratepayer. For this initial implementation of the program, we direct Pacific Gas and Electric (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison (SCE) to use RAM to procure at least 1,000 MW, allocated proportionally by retail sales to each IOU, over two years. All projects solicited through RAM must be 20 MW or less and located within one of the IOU's service territories. We require each IOU to determine upfront the types of products (e.g. baseload, peaking as-available, non-peaking as-available) they intend to procure under RAM to ensure their procurement is consistent with their portfolio needs. This will also provide developers and investors greater clarity and certainty regarding the market opportunity this program provides.

In each RAM solicitation, bids will be screened for viability and selected based on price, using a streamlined utility bid evaluation process that serves to expedite the procurement and review process and increase market transparency. While IOUs must follow these protocols for bid selection, they have the

discretion to reject bids if they determine that there was market manipulation and/or if the bid prices are not cost-competitive. Executed contracts resulting from RAM solicitations that fall under the IOU's allocated capacity cap, as described below, can be submitted through a simplified (Tier 2) advice letter process. This pre-approval process benefits all stakeholders by reducing the ratepayer's exposure to risk and allowing regulators to monitor the market before authorizing more RAM procurement.

Our intent in establishing RAM is to create a standardized procurement process for projects up to 20 MW in size in order to promote robust competition and reduce the administrative burden associated with these projects. Going forward, RAM should be the primary procurement vehicle for projects in this size range, though projects may still participate in the annual RPS solicitations and Commission-approved utility solar photovoltaic programs. It is contrary to the intent of this program to allow projects in this size range to use other procurement options, in particular voluntary programs that target the same market segment or bilateral negotiations. Thus, going forward, to the extent SCE wishes to continue to pursue this market segment, SCE shall conform its Renewables Standard Contract (RSC) program to the guidance and framework provided herein. However, SCE may count contracts already executed pursuant to its 2010 RSC towards its capacity cap to the extent they are approved by the Commission. Furthermore, SCE may submit additional contracts resulting from its 2010 RSC solicitation via a Tier 3 advice letter for Commission approval, however, these additional contracts will not further reduce SCE's procurement obligation under the RAM program.

Within 60 days, each IOU will file an implementation advice letter with its allocation of megawatts per product category, procurement protocols, and a standard contract that is consistent with the requirements in this decision.

Further, we authorize the Director of Energy Division to explore methodologies for evaluating the utilities' need for system-side renewable distributed generation up to 20 MW in coordination with Commission procurement planning and how we might integrate this need determination into the RAM program. In addition, we expect Energy Division and parties to continually monitor the RAM program, and recommend modifications based on evidence, if and as necessary. We authorize the Director of Energy Division to act on its own motion to revise any aspect of the RAM program through resolutions proposed for Commission approval. We summarize the adopted program in Appendix A. This proceeding remains open.

2. Background

2.1. Legislation and Initial Implementation

~~The Commission, in 1979, ordered the use of standard contracts for utility purchases of electricity from certain sellers at a price equal to the utility's full avoided cost. (See Decision (D.) 91109, D.07-07-027.) These sellers included projects generating electricity using renewable resources. As we described in earlier orders, this very successful program quickly grew to about one-third of California's electricity resource base. It evolved over time consistent with market restructuring. Related initiatives began in 2002 in the form of the California Renewables Portfolio Standard (RPS) program, seeking even more electricity generated by renewable resources. (See D.02-10-062, D.07-07-027 at 3-4.)~~

Beginning in 2007, California law required, as part of the RPS program, that every electrical corporation have a feed-in tariff ~~for~~(FIT) to purchase

electricity ~~sales by its~~at the market price referent (MPR) from renewable facilities up to 1.5 MW owned by public water and wastewater agency customers.~~[1]~~[1] ~~The tariff established terms for the sale to electrical corporations of electricity generated by water and wastewater agency retail customers using certain eligible facilities powered by renewable resources up to 1.5 MW at a price equal to the market price referent (MPR).~~[2] The tariffs were available until the combined statewide cumulative capacity of those facilities equaled 250 MW~~. The law also permitted the terms of the tariff to be offered in the form of a standard contract~~.

We implemented this law in July ~~2007. (See~~2007 in D.~~07-07-027.) We also ordered a limited expansion of this tariff~~07-07-027 and expanded the program at that time from water/wastewater agency retail customers to other customers ~~on the same basic terms and conditions (T&C) in the service areas of~~in the Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) service territories on the same basic terms and conditions. This added an additional 228 MW to the program, bringing the ~~combined statewide total of the two parts of this~~required FIT program total to 478 MW. We ~~did not close the inquiry, but directed that further consideration be given to limited issues for the purpose of completing implementation of the law. On August 1, 2007, the Administrative Law Judge (ALJ) sought parties' comments regarding those remaining issues. We~~ resolved applications for rehearing of D.07-07-027 in February ~~2008. (See~~2008 in D.08-02-010.~~) The tariffs~~ The resulting IOU tariffs –

[1] Pub. Util. Code § 399.20, added by Assembly Bill (AB) 1969 (Stats. 2006, ch. 731) effective January 1, 2007. Unless noted otherwise, all subsequent statutory references are to the Public Utilities Code.

~~[2] See Appendix B for a complete list of acronyms.~~

which we refer to as the "Existing FITs" and the entire program as the "Existing FIT"- became effective over the course of the next few months.

~~After considering parties' comments regarding remaining issues, an~~An Amended Scoping Memo and Ruling was filed on June 5, ~~2008.~~2008 (June 2008 Amended Scoping Memo and Ruling). The assigned Commissioner identified five issues for consideration, and set a schedule for comments and motions. The five issues were:

1. **Program Extension for San Diego Gas & Electric Company (SDG&E)**: Whether or not to extend the tariffs for water/wastewater customers to other customers in the service territory of SDG&E (as we had already done for other customers in the service territories of PG&E and SCE);
2. **Eligible Project Size**: Whether or not to increase the eligible project ~~(transaction)~~ size from 1.5 MW to 20 MW;
3. **Excess Sales**: How to count electricity purchased pursuant to an excess sales arrangement toward program limits;
4. **Third Party Ownership:** What changes, if any, are necessary to permit third party ownership; and
5. **Other**: Anything else a party recommends be considered by the Commission to complete implementation.

On July 3, 2008, comments were filed by 16 parties.[~~3~~2] On July 14, 2008, reply comments were filed by 13 parties.[~~4~~3]

[~~3~~2] Comments were filed by PG&E; SCE; SDG&E; PacifiCorp; Sierra Pacific Power Company (Sierra); Division of Ratepayer Advocates (DRA); Green Power Institute (GPI); Independent Energy Producers Association (IEP); Alliance for Retail Energy Markets (AReM); California Farm Bureau Federation (Farm Bureau); Sustainable Conservation; The Vote Solar Initiative (~~VSI~~Vote Solar); Recurrent Energy, Inc. (Recurrent); Solar Alliance ~~(SA)~~; The California Solar Energy Industries Association (CALSEIA); and GreenVolts. Comments of Sempra Energy Solutions LLC were served but not filed. These comments are referred to herein as Initial FIT comments.

[~~4~~3] Reply Comments were filed by PG&E, SCE, Sierra, GPI, AReM, ~~VSI~~Vote Solar, Recurrent, ~~SA~~Solar Alliance, CALSEIA, GreenVolts, The Utility Reform Network

The first of five issues was whether or not the existing program for public water and wastewater agency customers should be extended to other customers in the SDG&E service area. No party filed comments in opposition to the extension and, on September 18, 2008, the extension was adopted. (See D.08-09-033.) This added an additional 20 MW to the Existing FIT program, bringing the statewide combined total from 478 MW to 498 MW.

~~On September 28, 2008, the Governor signed Senate Bill (SB) 380 (Stats. 2008, ch. 554), amending § 399.20 effective January 1, 2009. Among other things, the new law requires that each electrical corporation have a tariff for the purchase of electricity from a retail customer (not limited to public water and wastewater agency customers) up to a combined statewide total of 500 MW.~~

~~On October 11, 2009, the Governor signed SB 32 (Stats. 2009, ch. 328), amending § 399.20 effective January 1, 2010. Among other things, the new law requires a tariff for the purchase by each electrical corporation of electricity up to 3 MW from any eligible facility (removing the retail customer provision) up to a combined statewide total of 750 MW (including approximately 250 MW for local publicly-owned electric utilities, also known as municipal utilities) at a price equal to an adjusted MPR. We will turn to implementation of SB 32, along with final implementation of AB 1969, after we address the new procurement protocol adopted here.~~

~~2.2. Project Size and Other Limited Issues~~

The second issue ~~(~~ - whether or not the eligible project size should be increased from 1.5 MW to 20 MW~~)~~ - involved considerable additional work. Among the comments, for example, some parties stated that additional ~~T&C are~~

(TURN), Farm Bureau and Sustainable Conservation. These comments are referred to herein as Initial FIT reply comments.

~~needed if~~terms and conditions would need to be added to the Existing FITs to accommodate increased project size ~~is increased~~.

On October 10, 2008, the Commission's Energy Division (ED) sought further data from parties on this issue. The information and comments were received on October 24, 2008. A second ED data request was issued on January 28, 2009, focusing specifically on contract ~~T&C~~terms and conditions. Parties submitted data responses and comments on February 4, 2009. On February 10, 2009, ED held a workshop regarding standard ~~T&C~~terms and conditions for a ~~feed-in tariff (~~FIT~~)~~.[5]

ED staff used this material to develop a proposal to expand the size of the Existing FIT. By ruling dated March 27, 2009, the ED staff proposal titled "Feed-in Tariff for Renewable Generators Greater than 1.5 MW" was filed and served ~~on~~to parties for comment. Among other things, ED stated that price level and rate structure are essential to FIT program success, and would be addressed in a future phase of the proceeding. Dates were set for comments and motions.

On April 10, 2009, comments were filed by 21 parties.[~~6~~4] On April 17, 2009, reply comments were filed by 10 parties.[~~7~~5] Some parties stated that price cannot

---

~~[5] In July 2007, we found that our adopted tariff with standard contract is a form of FIT. (See D.07-07-027, Finding of Fact 27 at 57, and footnote 40 at 44.) We refer herein to the current program up to 1.5 MW as FIT (existing).~~

[~~6~~4] Comments were filed by PG&E; SCE; SDG&E; DRA; TURN; Center for Energy Efficiency and Renewable Technologies (CEERT); GPI; Solutions for Utilities, Inc. (SFUI); Sustainable Conservation; Sierra Club ~~California~~ (Sierra Club); Community Environmental Council (Environmental Council); IEP; FuelCell Energy, Inc. (~~FCE~~FuelCell Energy); Redwood Renewables (RR); Los Angeles Community College District (~~LACCD~~LA Community College District); City of Santa Monica (Santa Monica); CALSEIA; ~~SA~~Solar Alliance and ~~VSI~~Vote Solar (jointly); First Solar, Inc. (~~FS~~First Solar); and AReM. These comments are referred to herein as the ~~T&C~~Terms and Conditions Comments.

be separated from FIT ~~T&C~~terms and conditions. Some stated that price is a critical element and its consideration should not be deferred. Others questioned the Commission's jurisdiction to set a FIT price.

By ruling dated May 28, 2009, parties were directed to file briefs on the jurisdiction issue, along with recommended pricing mechanisms consistent with their views on jurisdiction. Opening briefs were filed by 14 parties.[~~8~~6] Reply briefs were filed by 10 parties.[~~9~~7]

ED staff then prepared a pricing proposal, which forms the basis of the Renewable Auction Mechanism, or RAM, that we adopt today. RAM was developed by Paul Douglas, Jaclyn Marks and Sara Kamins of ED. Among the important features, the proposal ~~uses an~~abandoned the Existing FIT fixed price approach, instead proposing to use a market-based competitive auction mechanism to set the price paid to each energy seller.

By ruling dated August 27, 2009, the ED-recommended pricing proposal titled "Supply-Side Renewable Distributed Generation Pricing Proposal" was filed and served on parties for comment. Parties were also provided an opportunity to file final comments on pricing approaches, structures, designs and issues. Dates were set for comments and motions.

[~~7~~5] Reply Comments were filed by PG&E, SCE, DRA, GPI, CARE, Environmental Council, RR, CALSEIA, ~~SA~~Solar Alliance and ~~VSI~~Vote Solar (jointly). These reply comments are referred to herein as the ~~T&C~~Terms and Conditions Reply Comments.

[~~8~~6] Opening Briefs were filed by PG&E, SCE, SDG&E, DRA, California Attorney General (AG), GPI and Sustainable Conservation (jointly), Santa Monica, ~~FCE~~FuelCell Energy and CALSEIA (jointly), Cogeneration Association of California (CAC), Energy Producers and Users Coalition (EPUC, joining in the brief of CAC), ~~SA~~Solar Alliance and ~~VSI~~Vote Solar (jointly).

[~~9~~7] Reply Briefs were filed by PG&E; SCE; DRA; CAlifornians for Renewable Energy, Inc. (CARE); IEP; CEERT; ~~VSI~~Vote Solar; SFUI; and ~~FCE~~FuelCell Energy and CALSEIA (jointly).

On October 19, 2009, comments were filed and served by 24 parties.~~10~~[8] On October 26, 2009, reply comments were filed and served by 18 parties.~~11~~[9] No hearings were requested on any of the issues, and no hearings were held.

3. The Need For A Simplified Procurement Process For Small Generators

~~We now address the remaining four issues: project (transaction) size, treatment of excess sales, third party ownership and other. We address the biggest and most complex issue first: whether or not the project size and sales eligible for the FIT should be increased~~The inquiry initiated by the June 2008 Amended Scoping Memo and Ruling began with the question of whether or not to expand the Existing FIT program from 1.5 MW to 20 MW. ~~We cover this along with specifics for the new program in several chapters. We then turn to the remaining three issues.~~

~~The result is a new procurement tool. RAM applies to projects (transactions) up to 20 MW, uses an auction approach to price-setting, and is applicable to the three largest investor owned utilities (IOUs).~~

~~We begin our consideration of the issues by examining whether or not there is a need for an expanded FIT.~~

~~10~~[8] Comments were filed by PG&E; SCE; SDG&E; DRA; TURN; CARE; GPI; SFUI; CEERT; Santa Monica; FIT Coalition (~~FITC~~FIT Coalition); L. Jan Reid (Reid); CALSEIA; ~~VSI; SA; FS~~ Vote Solar; Solar Alliance; First Solar; IEP; Axio Power, Inc. (Axio); Recurrent; GreenVolts; ~~FCE~~FuelCell Energy; California Energy Storage Alliance (CESA); and Sempra Generation (Sempra). Separate joint comments were filed by PG&E, SCE, SDG&E, ~~SA~~Solar Alliance, GreenVolts, Sierra Club and Reid. These comments are referred to herein as Pricing Comments.

~~11~~[9] Reply Comments were filed by PG&E, SCE, DRA, TURN, GPI, SFUI, Reid, Sustainable Conservation, Sierra Club, Santa Monica, AReM, CALSEIA, ~~VSI, SA~~Vote Solar, Solar Alliance, Recurrent, ~~FCE~~FuelCell Energy, CESA, and Fortistar Methane Group (~~FMG~~Fortistar Methane). These reply comments are referred to herein as Pricing Reply Comments.

~~3. **Need for Expanded FIT**The inquiry began with the question of whether or not to expand the existing FIT program from 1.5 MW to 20 MW.~~ The desirability and need for ~~FIT program expansion~~a procurement mechanism to address the 1.5 MW to 20 MW market segment – which are still considered smaller generators - depends upon whether the current RPS bid solicitation and contract negotiation process ~~works reasonably well for smaller projects~~is adequate for procuring smaller projects. If the annual procurement process is not adequate for smaller RPS projects, the Commission should consider whether these projects provide a particular value to the market, utilities, ratepayers and regulators, and whether these projects should be pursued through a more targeted procurement process.

Parties present differing views on the efficacy of the current RPS program for small projects. For example, Environmental Council, CEERT, DRA, First Solar, GPI, IEP and others assert that the RPS program is currently not working successfully for small projects, while TURN ~~and others argue~~initially argued that it is successful and no change is necessary.[10] Nonetheless, there is considerable agreement that ~~even if not necessary,~~ it is feasible and desirable to streamline the process for smaller projects.

Many parties[11] also argue that renewable system-side distributed generation (DG) projects that interconnect on the utility side of the meter[12] present unique value to California ratepayers that is not captured in the annual

[10] TURN initially argued in its Terms and Conditions Comments that an expanded FIT was unnecessary, but in its comments on the Staff Pricing Proposal, TURN stated its support for a more streamlined and expedited process for small projects since they can not effectively participate in RPS solicitations.

[11] CEERT, CESA, FIT, Solar Alliance/Vote Solar, First Solar, CalSEIA, and the Community Environmental Council.

[12] Referred to as "system-side DG" in this decision

RPS solicitations. According to CalSEIA, these benefits include: rapid development timeline, electricity production close to demand, reduced congestion on distribution feeder line circuits, reduced demand for peak power, job creation in a local community, and compliance with the state's renewable energy targets.[13] CEERT similarly states, "These [system-side DG] projects are critical to rapid deployment of renewables because of their shorter development timelines, minimal site control and permitting constraints, and proximity to load."[14] CESA also notes that DG located near load centers should play an increasing role in the California RPS because they face fewer permitting and siting problems than central station RPS facilities.[15] Solar Alliance's comments, consistent with Energy Division staff's findings in its 33% RPS Implementation Report[16], say that smaller RPS projects can "act as an important hedge or safety valve for the RPS to meet the 20% and 33% goals, should the larger RPS projects not come on-line at the pace that is expected."[17]

We agree that ~~additional simplification~~it is desirable to simplify the procurement process for relatively smaller ~~projects. We streamline the process here to facilitate development in this project size range, while mitigating cost~~RPS projects and that these projects provide unique value to the RPS program because of their potential to be deployed quickly with a relatively smaller environmental footprint and minimal transmission need. Such streamlining

[13] CalSEIA Terms and Conditions Comments at 2.

[14] Terms and Conditions Comments at 2.

[15] Pricing Comments at 2.

[16] For the complete report, see http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm

[17] Pricing Comments at 3.

should also facilitate development of projects up to 20 MW by mitigating costs and administrative ~~burden~~burdens on projects, developers, utilities, and regulators. Further, the majority of parties support ~~FIT program expansion~~a simplified procurement process if there is the right balance of terms, conditions, and prices. We agree. All elements of ~~a FIT~~the procurement process must be considered, and we do so in adopting the right balance of terms, conditions, and prices ~~for the expansion~~ here in the form of the RAM.

~~It is important to note that we provide RAM as an additional tool for the IOUs to reach RPS targets and goals, along with other state goals,[12] but do not foreclose any project from using an alternate approach which works better for the seller. Some alternative approaches include, for example, annual RPS Procurement Plan competitive bid solicitations, bilateral negotiations, the qualifying facility (QF) market, procurement pursuant to each IOU's long term procurement plan (LTPP), the existing FIT to 1.5 MW (which may be expanded up to 3 MW pursuant to SB 32), Self Generation Incentive Program (SGIP), California Solar Initiative (CSI) program, SCE photovoltaic (PV) program,[13] PG&E PV program,[14] net metering program, IOU voluntary programs, and the California Independent System Operator (CAISO) short-term (day ahead) market. We continue to seek additional efficiencies and improvements in all RPS procurement, including reasonable uniformity in procurement documents and model contracts used in the annual bid solicitation.[15] Procurement generally, and~~

~~[12] For example, the loading order in Energy Action Plan II, resource adequacy goals, greenhouse gas (GHG) goals, reduction of reliance on foreign fuels, sustainable economic development, public health and safety.~~

~~[13] See D.09-06-049.~~

~~[14] See D.10-04-052.~~

~~[15] We have said this repeatedly, and most recently, for example, in D.09-06-018 at 52-53.~~

RPS procurement in particular, must be no more complex than necessary to achieve the state's goals. We secure additional efficiencies for smaller RPS-eligible projects here, and continue to encourage IOUs and parties to propose additional efficiencies and improvements.[16]

Our determination to expand the FIT raises issues about project size, optimal pricing approach, jurisdiction to set the price, and the right balance of T&C. We first turn to project size.

4. **Project Size**

4.1. **Positions**

Parties present a wide range of project sizes that should be eligible as part of reasonable FIT expansion. That range varies from keeping the existing program (i.e., up to 1.5 MW per project) to unlimited MW per project.

CARE, AReM, SCE and others, for example, believe project size should remain at 1.5 MW.[17] TURN supports two MW for a fixed price FIT,[18] or between three and 10 MW if the price is based on an auction.[19] PG&E and others argue project size should be limited to three MW for several reasons, including recognition of the legislature's most recent guidance in SB 32. SDG&E asserts system impacts on smaller utilities necessitate a limitation of five MW. ED staff

---

[16] The proposed efficiencies and improvements may include combining programs, where reasonable, to ensure that we have no more programs than are manageable while meeting legitimately different stakeholder needs and legislative requirements.

[17] If based on a competitive market price, CARE supports greater than 3 MW to less than 20 MW. (Pricing Comments at 4.)

[18] T&C Comments at 3.

[19] Pricing Comments at 1, assuming SB 32 implementation of a fixed price FIT up to three MW.

and others recommend a must-take FIT for projects up to 10 MW, with utility discretion to take or reject contracts for projects between 10 MW and 20 MW.[20]

IEP, DRA, Sierra Club, Environmental Council and others recommend FIT project size be increased to 20 MW. GPI and others argue that a must-take FIT should apply to projects larger than 20 MW. GPI prefers a must-take FIT up to at least 60 MW.[21] CEERT says it would eventually "like to see the cap on project size removed so that projects of all sizes may be eligible for the must-take FIT program."[22] LACCD does not support a project size cap, believing a FIT should be available to any size project.[23]

4.2. **Discussion**

4.2.1. **20 MW**

We adopt a project size of 20 MW. We do this as part of our goal to streamline the entire RPS program where feasible and reasonable. This can be done here for projects up to 20 MW. We adopt this limit for many reasons.

The California Energy Commission (CEC) has repeatedly recommended that we study and implement a FIT for projects up to 20 MW.[24] We do so

---

[20] FIT (existing) is a must-take tariff. Must-take here means the IOU must enter into the standard contract and purchase electricity a project sells pursuant to the terms and conditions of the tariff and standard contract. The terms and conditions may include maximum limits on IOU contracts (e.g., a MW cap, such as the initial FIT (existing) 250 MW total program cap pursuant to AB 1969). Terms and conditions may also include provisions under which an IOU may decline to take the electricity under a signed contract (e.g., system emergencies or other curtailments).

[21] T&C Comments at 5.

[22] T&C Comments at 4.

[23] T&C Comments at 3.

[24] See California Energy Commission 2006, *2006 Integrated Energy Policy Report Update*, CEC-100-2006-001-CMF, January 2007 at E-6; California Energy Commission 2007, *2007 Integrated Energy Policy Report*, CEC-100-2007-008-CMF, January 2008 at 6; California

consistent with CEC's recommendations. CEC also recommends continued evaluation of a FIT for projects over 20 MW.[25] We will do so as part of our ongoing assessment of the RPS Program, including consideration of how well other tools are working (e.g., bilateral negotiations, QF market, annual RPS competitive bid solicitation, RPS FIT (existing), combined heat and power (CHP) tariffs,[26] IOU PV programs, IOU voluntary programs, SGIP, CSI, net metering, CAISO day-head market).

Twenty MW is also consistent with Commission decisions. We have established certain contract provisions for small sellers because we have found they are unable to bid into a utility request for proposal, and generally do not have the resources or expertise to negotiate and enter into a bilateral contract. We define the size of those small sellers as 20 MW and less. (See D.07-09-040 at 121.)

Several existing programs use a 20 MW threshold and influence our decision here. For example, SCE has a standardized contract program for any project using renewable technology up to 20 MW. (See D.09-06-018 at 59.) For its Renewables Standard Contracts (RSC) program, SCE uses a simplified version of the pro forma (model) RPS contract used by SCE in its annual competitive solicitation. SCE says the RSC program addresses difficulties faced by smaller projects (i.e., those up to 20 MW) when they try to participate in annual RPS

Energy Commission 2008, *2008 Integrated Energy Policy Report Update*, CEC-100-2008-008-CMF, November 2008 at 29; California Energy Commission 2009, *2009 Integrated Energy Policy Report*, Final Commission Report, December 2009, CEC-100-2009-003-CMF at 230.

[25] California Energy Commission 2008, *2008 Integrated Energy Policy Report Update*, CEC-100-2008-008-CMF, November 2008 at 27.

[26] See D.09-12-042.

solicitations, and eliminates the need for complex negotiations. (See D.08-02-008 at 42-44.[27]) In recent discussion on SCE's RSC program, we stated that we see great merit with increased standardization, recognized SCE's initiative and innovation with its program up to 20 MW, and encouraged other utilities to adopt a similar approach for projects up to 20 MW.[28] (See D.09-06-018 at 62.)

In 2009, PG&E proposed a solicitation as part of its solar PV program for projects up to 20 MW. (Application 09-02-019.) A 20 MW size potentially has merit in many contexts, and we agree with DRA that PG&E's recommendation for a project limitation of 10 MW here is inconsistent with PG&E's proposal for 500 MW of PV installations up to 20 MW for its PV program.[29] We recently approved PG&E's PV program for projects up to 20 MW. (See D.10-04-052.)

---

[27] SCE recently said of its RSC program for projects up to 20 MW: "Through this program, SCE has sought to remove some of the barriers that smaller projects may have had when participating in SCE's annual solicitations. Such barriers have been especially evident for projects with smaller generating capacities. By offering standardized contracts for smaller projects, SCE hopes to increase opportunities for such projects to execute contracts with SCE and contribute to the State's RPS goals." (Advice Letter 2356-E (July 1, 2009) at 3.)

[28] SCE's RSC program initially set the price at MPR. SCE reports that late in 2009 it received a large number of applications for its RSC program, representing nearly double the program goal of 250 MW. SCE says it completed negotiations and executed contracts with 13 projects by early January 2010. On March 29, 2010, SCE filed Advice Letter 2457-E seeking approval of the 13 contracts. SCE also reports that it suspended the RSC program after executing the contracts in January 2010, and conducted an analysis of options to restart the program in 2010. SCE states that, based on its analysis and after consultation with its Procurement Review Group (PRG), it has initiated a revised RSC program with a new goal of 250 MW. SCE says the 2010 program will not offer a price at MPR, but will award contracts based on Requests for Offers conducted twice per year. (June 17, 2010, SCE Second Amended 2010 RPS Procurement Plan, Attachment 1 at 28-30.) SCE officially launched its 2010 RSC Request for Offers on August 2, 2010. It is open to all RPS technologies of 20 MW or less.

[29] DRA T&C Reply Comments at 7.

State law requires electrical corporations to have tariffs and standard contracts for purchases of electricity from certain customers up to 20 MW. (See § 2840 et seq. regarding CHP.) Federal regulations draw an important distinction for similar projects at 20 MW.[30] Small and large generators are differentiated at 20 MW for purposes of interconnection requirements.[31]

For all these reasons we find smaller projects, which are those up to 20 MW, should be eligible for the new RAM procurement program adopted here.[32] We address in our discussion below (regarding Program Design) whether or not RAM should be a must-take obligation.

4.2.2. Other Arguments

We consider but reject other arguments for a lower project size.

4.2.2.1. Interconnection, Stability, Cost

SDG&E and several parties argue for a lower limit, asserting that large projects may create significant problems with interconnection, system stability, or other concerns. We are not convinced.

Each project must successfully navigate the interconnection process before it can be interconnected. This process includes performing system stability and cost studies, and determining necessary interconnection equipment to permit

---

[30] 18 CFR 292.309(d)(1) establishes a rebuttable presumption that a QF with capacity at or below 20 MW does not have nondiscriminatory access to the wholesale electricity market. Also see 18 CFR 292.601 regarding certain exemptions from federal and state law for QFs at or below 20 MW.

[31] For example, see SCE 2009 RPS Procurement Plan Request for Proposals at Section 7.04.

[32] FERC applies a 30 MW threshold for some purposes. (See 18 CFR §§ 292.601(b) and 292.602(a).) We decline to use 30 MW here, but will consider amounts greater than 20 MW in relationship to CEC's recommendation for continued evaluation of expanding the FIT to projects larger than 20 MW.

safe and reliable operation. An interconnection does not occur unless and until the project successfully passes necessary and reasonable requirements, and agrees to pay appropriate costs. This is true for any size project, from less than one MW to several hundred MW. Synchronized operation is not permitted unless and until the system may be operated safely.

Projects of all sizes may interconnect with IOU systems. No evidence shows that interconnection requirements differ depending upon whether the electricity price is reached via bilateral negotiation, annual competitive bid solicitation, FIT, full avoided cost QF standard contract, auction, or another process. Furthermore, CAISO, a party to this proceeding, presents no concerns with increasing eligible project size to 20 MW. The evidence demonstrates that existing stability studies, reliability studies, cost studies, and interconnection requirements adequately address these concerns for all projects, including those at and below 20 MW, whether the project price is determined via a FIT or some other process. In addition, we have more than 30 years of experience with projects of 20 MW and less paid the utility's avoided cost (e.g., QF program), and no evidence presented here shows any particular problems.[33]

SDG&E argues that:

> "As project size increases to 5 MW, the probability that system upgrades will be required also increases. As shown in the illustrative example in Attachment A [to SDG&E's T&C Comments], system upgrades that could be required to

[33] The California QF program began in 1979. It included, among other things, an IOU must take requirement when the seller elected to enter into the standard contract; standard contracts without the need for further negotiation; fixed prices, or some portion of the prices subject to known changes (e.g., heat rates times current oil/gas prices updated monthly for the energy price component).

accommodate projects sized greater than 5 MW would be prohibitively expensive."[34]

This is not an impediment. We are convinced by Solar Alliance and Vote Solar that prohibitive costs deter developers:

> "Many of the IOUs' concerns fall by the wayside when one considers SDG&E's acknowledgement (comments at p. 11) that generators are responsible…for interconnection and distribution upgrade costs. In other words, interconnection costs…are likely to be a potent deterrent for developers to interconnect a system beyond what the interconnected distribution system can handle without significant upgrades. This more than adequately addresses SDG&E concern regarding the maximum size limit for projects in SDG&E's service territory. As SDG&E acknowledges (comments at p. 11), '[p]rojects sized above 5 MW are likely to require significant system upgrades…making such projects poor candidates for the FIT Program.' "[35]

We also disagree with SDG&E's argument that project size must be 5 MW or less to avoid burdensome upgrade costs that will bog down the FIT program. Projects of any size can clog FIT or RAM program implementation. Other program elements can successfully address this concern. We adopt a timeframe, administrative process and program requirements below which obligate RAM projects to interconnect and begin operation or face removal from the RAM option and be subject to financial consequences (e.g., 18 months to begin commercial operation, with limited extensions; project viability criteria; deposit forfeiture). This will naturally channel projects that will take a longer amount of time to other procedures (e.g., annual bid solicitation, bilateral negotiation).

[34] T&C Comments at 5-6.

[35] Joint T&C Reply Comments at 3.

~~SDG&E states that the project size capable of interconnection is limited by conductors and other equipment at the point of interconnection. SDG&E says its distribution voltages are four kilovolt (kV) and 12 kV, in contrast to PG&E's 21 kV and 34.5 kV and SCE's 66 kV and 115 kV.[36] SDG&E concludes that what may work for PG&E or SCE will not work for SDG&E. We agree.~~

~~Different size systems and circuits may permit interconnection of different size projects without large interconnection costs or effects. Others may not. We need not adopt different size project limits by circuits, systems or utilities, however. The evidence shows that existing interconnection procedures and resulting equipment satisfactorily protect systems, while costs screen economic from uneconomic interconnections.~~

~~4.2.2.2. Number of Projects~~

~~TURN asserts that expansion beyond two MW is unnecessary since a significant number of projects between two and 10 MW have RPS contracts. We are not persuaded for four reasons.~~

~~First, program improvements may be made at all MW size levels by increased standardization, uniformity and transparency. We particularly think this is true in the range up to 20 MW, and this is independent of the number of projects that now do or do not have contracts. Second, we have previously found that small sellers are generally unable to participate in a competitive solicitation, and do not have the resources or expertise to negotiate and enter into a bilateral contract. Several parties renew that concern here, and we continue to be convinced. Third, SA, VSI and Environmental Council reasonably show~~

~~[36] T&C Comments at 5. SCE says a 12 kV circuit is a common distribution voltage for SCE, and identifies a 66 kV circuit as "subtransmission." (T&C Comments at 8.)~~

~~TURN's conclusion about the number of projects being significant is overstated.[37] In fact, the number is modest. Fourth, TURN presents no evidence that the current number of signed projects reasonably exhausts the potential in this size range. To the contrary, ED staff and others show that there is opportunity for potentially thousands of projects totaling thousands of megawatts in this small size range if the program is reasonably designed.[38] We do that here, with not only reasonable design but also appropriate limits to ensure that the RAM program grows in a manageable and efficient way.[39]~~

~~4.2.2.3. **Risk**~~

~~PG&E says FIT project size must be limited to no more than 10 MW. PG&E argues that larger projects pose greater risk to the buyer and seller, including the risk of system imbalances. We have addressed the risk of system imbalances above, and we do not agree with PG&E's recommendation.~~

~~[37] See, for example, Environmental Council T&C Reply Comments at 6-9; SA Pricing Reply Comments at 7.~~

~~[38] FITC states that the amount of generation capacity that could be connected at the distribution level is over 27 gigawatts (GW) in 2008, and is estimated to be over 40 GW by 2020. (Pricing Comments at 12-13, citing "Distributed Renewable Energy Assessment Final Report, Navigant Consulting, August 11, 2009, CEC at 30.) SA says there is 27.5 GW of potential distributed PV generation next to existing electrical substations. (Pricing Comments at 24, citing Renewable Energy Transmission Initiative, Phase 1B (January 2009) at 6-25.) For comparison, CEC reports that the installed capacity of in-state power plants (greater than 0.1 MW) is 67.5 GW. (See CEC Energy Almanac on CEC web page: http://www.energy.ca.gov/.)~~

~~[39] For example, we adopt a total capacity (MW) limit so that we do not repeat the overly successful QF program experience from the 1980s, wherein MW subscriptions exceeded expectations before we were able to suspend the standard offer. In adopting that suspension, we acknowledged that "rapid changes in the QF market have outstripped the pace of our regulatory process." (D.85-04-075, 17 CPUC2d 521, 535.) We learn from that experience, and take a pragmatic approach here.~~

~~PG&E also says larger projects increase the risk of harm to the buyer if the generator fails to achieve commercial operation or satisfactorily perform.[40] We are not convinced.~~

~~Reasonable risk balancing among all RPS program stakeholders is a consideration at all project sizes, from less than 1 MW to hundreds of MWs. PG&E's recommended MW limit is not necessarily the most effective tool to address this potential risk. Rather, contract terms and conditions (e.g., deposit amounts) are better tools to address and allocate risk among buyer, seller and other stakeholders.~~

~~Moreover, risk is relative to several factors and must be considered at several levels. For example, there is systematic risk.[41] No evidence shows that systematic risk changes at a project size of 10 MW or 20 MW. To the contrary, systematic risk is likely to affect all projects subject to the particular risk factor independent of project size.~~

~~There is also project specific risk.[42] In general, project risk is diversified when spread over many projects. It is also addressed by contract T&C (e.g., deposits, damage provisions). California's resource base is in excess of 67,000 MW, and there are hundreds of electric generators. No party presents~~

~~[40] T&C Reply Comments at 4.~~

~~[41] Systematic (un-diversifiable) risk is the risk of (or to) an entire market. It includes exposure to wide-spread project failure due to economy-wide variables (e.g., recession; inflation; financial market dysfunction; changes to input prices affecting all firms, such as labor, fuel, cost of capital). It also includes exposure to wide-spread project failure of all projects using one type of technology (e.g., suspension of operation or new development of one technology type for a reason that applies to all projects using that technology).~~

~~[42] For example, project specific risk is the failure of a particular project to reach commercial operation, or perform reasonably over time, due to problems that are individual or unique to that project.~~

~~compelling evidence that the concentration or number of projects in the instant range (20 MW or less) is likely to be so great due to the procurement choices presented here (compared to other procurement methods or pricing protocols within a procurement method) as to materially affect risk in an adverse way not reasonably addressable by contract T&C. Nor is any compelling evidence presented that this risk, if any, is materially affected by selection of a project size less than 20 MW when this risk is reasonably addressable by contract T&C. Finally, the risk is moderated by the adopted program cap of 1,000 MW.~~

~~4.2.3. Transactions~~

~~PG&E, SCE and SDG&E must offer existing FIT customers the choice of selling electricity under an arrangement of either (a) full buy/sell or (b) excess sales. (See D.07-07-027 at 33-38.) Under full buy/sell, the customer sells its entire output to the utility, and buys back the electricity it needs to meet its load. Under excess sales, the customer sells only the electricity that is excess to its own needs.[43]~~

~~We clarify that the 20 MW limit adopted for RAM applies to the amount of the transaction. It is not a size limitation on the seller's facility. For full buy/sell, this is 20 MW for the transaction, which is the entire project. For excess sales, this is 20 MW of sales to the IOU (i.e., the amount of the transaction), which is the amount the seller is selling, the IOU is buying, and the IOU may count for RPS counting purposes (e.g., annual procurement target). This is consistent with treatment under the existing FIT,[44] and our discussion below regarding the excess sales option (e.g., how to count excess sales capacity toward maximum~~

~~[43] A project using an excess sales arrangement pursuant to the existing FIT may be greater than 1.5 MW, but the sale (transaction) is limited to 1.5 MW.~~

~~[44] See D.07-07-027 at 36-37.~~

~~total statewide capacity). Thus, for purposes of RAM, just as with FIT (existing), project means the size of the transaction, not the size of the facility.~~

~~4.3. Conclusion~~

~~Therefore, we adopt a project (transaction) size of 20 MW. This is up to 20 MW of sales, whether from the full project or excess sales. We next address the pricing approach, and whether the rate should be fixed or market-based.~~

4. ~~5. Pricing Approach~~Pricing Approach – The Renewable Auction Mechanism

~~This section considers policy, practical and other arguments regarding whether the rates in the expanded FIT should be (a) fixed by the Commission or (b) market-based.[45] We adopt, for the reasons explained below, the market-based RAM recommended by ED.~~

4.1. ~~5.1.~~ Background ~~and Options~~

The ~~existing~~Existing FIT for projects up to 1.5 MW uses a fixed ~~rates~~price set by the Commission, equal to the MPR, and stated in a published tariff. ~~Upon implementation of SB 32, the FIT for projects up to three MW will use a fixed rate equal to the MPR, subject to adjustment for current and anticipated environmental compliance costs and limited by a ratepayer indifference test. This statutory, Commission-determined, MPR-based fixed pricing approach~~

~~[45] A market is any structure that allows sellers and buyers to exchange goods or services. A market may be competitive, non-competitive, or partially competitive. Market-based is used here to distinguish this rate-setting approach from one where the rate is set by the Commission. Market-based used in this decision means the rate is determined by the seller and buyer, not the Commission. (The rate for a particular contract is determined by the seller via seller-submitted non-negotiable bids; it is determined by the buyer via the buyer's selection of projects by price in least-costly order; the two elements interact to determine the unique price for each selected project.) In both cases (market-based and Commission-set), the rate is determined before the product exchange occurs between seller and buyer.~~

~~applies, and will continue to apply, to FIT (existing) tariffs independently of anything decided here.~~ For the RPS annual solicitations, sellers submit bid prices to a utility and these prices are subject to negotiations, which can take up to a few years, before the contract is finalized. The initial inquiry into expanding the ~~FIT~~Existing FIT in the June 2008 Amended Scoping Memo and Ruling did not separately scope ~~the FIT rate~~pricing as an issue. In August 2009, ED proposed that the ~~expanded FIT rate~~price for the new program be established by use of a market-based competitive auction mechanism ~~named~~- the RAM. The RAM employs an auction, wherein sellers which meet certain minimum criteria are eligible to submit non-negotiable price bids. The buyer then selects winning sellers based on the lowest ~~price.~~ priced bids first, and signs non-negotiable standard contracts with the winning sellers, incorporating the prices bid by that seller. The cost of RAM, as proposed by ED, would be contained with an authorized revenue requirement for the program.

The Staff Proposal suggests that using an auction to set contract prices may induce developers of system-side renewable DG to bid the lowest prices they would be willing to accept to develop renewable energy projects. This mechanism would also allow the state to pay developers a price that is sufficient to bring projects online but that does not provide surplus profits at ratepayers' expense.

4.2. Parties' Positions

In response to ED's proposal, parties argue in favor of ~~several ways by which the expanded FIT rate might be determined. In summary, the options are rates that are either (a) fixed and published, (b)~~two primary pricing methodologies: (1) fixed and published rates; or (2) contract prices established

via a market~~, or (c) a hybrid approach (combining fixed and market elements). These methods include, but are not limited to:~~ .

- ~~**Fixed and Published:** Fixed and published in a public source based on (a) cost of the seller (plus or minus adjustments),[46] (b) cost of the buyer (e.g., buyer's avoided cost, plus or minus adjustments) or (c) pragmatic approaches (e.g., increasing or decreasing a fixed FIT rate based on actual delivered energy and desired quantity).[47]~~
- ~~**Established via Market:** Determined by the market based on (a) auction or (b) bilateral negotiation.~~
- ~~**Hybrid Approach:** Hybrid (combination of setting the rate and using the market) such as (a) market price derived from a market based referent (e.g., MPR; MPR plus or minus adjustments or caps) or (b) a fixed FIT rate set in year x+1 based on competitive market price results in year x.[48]~~

~~[46] SFUI recommends the price be set at the seller's cost including a 15% profit, be technologically indifferent, and be available up to three MW, with the generator maintaining ownership of the REC. (Pricing Comments at 8.) Santa Monica recommends a 5% after tax return for certain small projects. (Pricing Comments at 3.)~~

~~[47] IEP recommends that the initial FIT rate for the first tranche (group) of projects be increased or decreased for the next tranche based on whether a target quantity of renewables is reached in the first tranche. IEP contends this approach retains the simplicity of a true FIT but provides price adjustments prospectively based on market feedback. (Pricing Comments at 2.) CALSEIA recommends that a ratesetting Committee (consisting of major stakeholders convened by the Commission) adjust the initial FIT rate on a regular schedule to achieve the necessary trajectory to reach a stated goal, such as 33% by 2020. This approach will achieve the ultimate goal at least cost, according to CALSEIA. (Pricing Comments at 6.)~~

~~[48] FSI says the reference rate in year x may be set based on one of several metrics from other competition-based programs (e.g., competitive bidding in PG&E and SCE solar PV programs). Metrics include using the weighted average of winning bids, the median winning bid, the highest bid, or the lowest bid. This rate becomes the fixed rate in year x+1. The rate is updated each year (e.g., the rate in year x+2 is based on updated data using the same approach applied to determine the rate in year x+1.) This approach moderates the uncertainty of an unknown price (by setting a fixed price) and increases~~

Several parties advocate ~~a~~for an administratively determined fixed-rate FIT.[~~49~~18] In support, they assert a fixed rate set in advance in a published, publicly available tariff makes the price transparent and easily known to all stakeholders. In their view, the advantages of this approach include providing price certainty for project evaluation and cost recovery, reducing transaction costs, moderating program administrative costs, and protecting ratepayers against excessive prices.

Other parties recommend a fixed ~~FIT~~ rate FIT for projects up to a certain size (e.g., ~~three~~3 MW in Senate Bill [SB] 32[19]), and ~~a~~the RAM for larger projects.[~~50~~20] Among the reasons in support, advocating parties say this approach provides transactional efficiencies for the smallest projects, employs the latest guidance from the legislature, and secures the benefits of competitive markets for relatively larger projects.

~~transparency while meeting the Commission's need to use a market mechanism, according to FSI. At the same time, FSI says the approach avoids concerns raised by a blind bid. (Pricing Comments at 5-6.)~~

[~~49~~18] These parties include ~~FITC~~FIT Coalition, Santa Monica, SFUI, CALSEIA, GPI, IEP, ~~CESA~~CEERT, Solar Alliance and Sierra Club ~~California. Sierra Club California, for example, says: "There is no need to introduce a complicated mechanism like Reverse Auction Method. RAM introduces complexities that will imperil the workability of the entire FIT enterprise." In addition to the potential for price collusion, Sierra Club California says "we add to this the risk of a nominally competitive market based system … namely that combining 1) a government mandated demand under the RPS with 2) a market price bidding system that 3) has constrained supply, can drive up prices." In contrast, Sierra Club California says "having the buyer of renewable energy provide a set standard price – as in a Feed-in Tariff – removes the seller's power over the market and gives the pricing power to the buyer." (Pricing Reply Comments at 5-6.)~~.

[19] Stats. 2009, ch. 328

[~~50~~20] This is a primary recommendation for some, and an alternate recommendation for others, including DRA, GreenVolts, Axio and CARE.

Many parties support setting the ~~FIT rate via the RAM.[51]~~price for the new procurement mechanism through ED's proposed auction approach – the RAM.[21] In their view, this approach ~~provides that~~, where bidders receive the price they bid, captures changing market prices in a timely way, is easy to implement, and can provide ~~cost-containment along with cost certainty for ratepayers, IOUs and projects.~~ competitive market prices for ratepayers, IOUs, and sellers. TURN, for example, supports RAM over an administratively set fixed-rate program since RAM "provides greater developer certainty to promote DG projects while minimizing the potential for significant windfall profits at ratepayer expense."[22] Solar Alliance argues that RAM's competitive process drives down electricity costs, which can offer ratepayers rapid price adjustments.[23] Further, Recurrrent prefers RAM over a fixed rate because it avoids the ratepayer backlash of setting the rate too high, as occurred in Spain and Italy. [24]

~~Finally, some parties recommend a hybrid approach. In support, they assert this secures the benefits of competitive results but provides transparency, price certainty, transaction cost savings and ratepayer protection.~~

~~5.2. Competitive Market Approach~~

~~We adopt a competitive market approach for setting the FIT price. Within that approach, we adopt RAM as the particular mechanism for price determination. RAM is a form of auction, wherein projects which meet certain minimum criteria are eligible to submit non-negotiable price bids. The buyer~~

~~51~~21 These parties include PG&E, SCE, SDG&E, Recurrent, Reid, TURN, ~~SA~~Solar Alliance and ~~VSI~~Vote Solar.

22 Pricing Comments at 1.

23 Pricing Comments at 11.

24 Pricing Comments at 2.

~~then selects winning projects based on the lowest price. We adopt this approach for several policy, practical and other reasons.~~

~~5.2.1.~~

4.3. Discussion

4.3.1. Policy

~~Our overall policy is to offer every reasonable opportunity for stakeholders to meet the state's many goals and targets, including RPS, GHG, resource adequacy, portfolio mix, and others. We do this differently in different markets based on the underlying market structures and statutes. In all cases, we do this in a way that results in just rates, reasonable rates, avoidance of undue discrimination, economic efficiency, equity among stakeholders, and optimal outcomes. In particular, this requires different policies in the QF and RPS markets. We first briefly look at the QF market given its close relationship to the RPS market, including jurisdictional issues discussed below.~~

~~The QF market was initially a monopsony (single buyer). It was established, and continues to function, under its own set of statutes and regulations. It remains carefully regulated to produce an economically and socially optimal outcome (parallel to state regulation of monopoly markets to reach an economically and socially optimal outcome). Some electricity markets, or market segments, are in the process of change, but it is clear that sufficient competition does not exist in all cases to fully protect buyers, sellers and other stakeholders.[52] For example, as recently as 2007 we said that QFs of 20 MW and less generally do not have the resources or expertise to negotiate individual contracts with an IOU. (See D.07-09-040 at 118-119.) This market segment, absent one side having the resources or expertise to negotiate, cannot rely on~~

~~[52] Some segments may be an oligopsony (few buyers) or an oligopoly (few sellers).~~

~~pure competition to reach optimal outcomes. We reaffirm that here. Consistent with our conclusion, the Federal Energy Regulatory Commission (FERC) has established a rebuttable presumption that projects of 20 MW and less do not have nondiscriminatory access to the wholesale electricity market. (18 CFR § 292.309(d)(1).)~~

~~Therefore, the wholesale market for QFs of 20 MW and less is not sufficiently competitive to relax regulation and rely solely on buyers and sellers determining prices, terms and conditions to reach a just and reasonable result. We cannot, and do not, expect the transactions of private parties in the QF market, absent responsible regulation, to result in an optimal outcome.~~

~~We have typically used standard contracts with fixed rates set at full avoided costs in the QF market. Statutes provide that we employ fixed rates in some other markets (e.g., CHP; small RPS projects up to 1.5 MW, expandable up to 3 MW pursuant to SB 32). We will continue to use fixed rate tariffs and other tools in the QF, CHP and other markets, as appropriate, and need not duplicate that here.~~ **and Practical Considerations**

The RPS statute and program~~, by contrast,~~ were conceived, initially designed, and remain focused on ~~this~~the renewable market segment being competitive. We ~~continue that focus. We adopt necessary safeguards to protect stakeholders from adverse outcomes if the market is not sufficiently competitive to reach just, reasonable, efficient, and optimal results. Those safeguards include, for example, total program capacity, a reasonableness threshold for simplified contract review, and ongoing reporting.~~use this preference in our consideration of the appropriate RAM pricing mechanism. In addition, as discussed in Section 3, we see the need to adopt a new procurement tool that simplifies the procurement process for the system-side renewable DG market.

To accomplish this objective, and to design an efficient and effective program, the pricing mechanism should satisfy staff and parties' policy and administrative priorities. These goals include, but are not limited to: 1) lowering transaction costs for the buyer, seller, and regulator, 2) executing contract prices that are financeable for the developer but also not an overpayment from a ratepayer perspective, 3) the ability to respond quickly to market changes, and 4) promoting the development of a long-term sustainable market.

~~We also note that most, if not all, RPS sellers may obtain QF certification.[53] That is, where appropriate and desirable, an RPS seller may obtain QF certification and avail itself of the QF program.[54] This provides necessary protections against monopsony (or other) bargaining advantage and non-optimal market outcomes in the smaller project size RPS market at issue here. It provides smaller RPS sellers with another venue for transactional efficiencies when they have limited resources and expertise (i.e., QF standard contract at a just and reasonable avoided cost rates). We adopt policies below which depend on the RPS market being competitive, but rely on this link with the QF market as an additional protection for sellers. It also provides a check and balance between the two markets so that the each market result should be just, reasonable, nondiscriminatory, and optimal.~~

~~[53] One category of QF is that of small power producer (SPP). An SPP must use for its primary energy source biomass, waste, renewable resources, geothermal resources or a combination thereof, with a limit on the total energy input from any other source, and subject, in some cases, to a maximum size of 80 MW. Another type of QF is a hydroelectric SPP located at a new dam or diversion, subject to certain environmental and other limitations. (18 CFR § 292.203.)~~

~~[54] An RPS-eligible seller of 1 MW or less who is also eligible to be a QF (e.g., SPP powered by renewable resources) is exempt from FERC filing requirements to obtain QF status. (130 FERC ¶ 61,214 (March 19, 2010); 18 CFR § 292.203(d)(1).)~~

~~These policy considerations give us reasonable confidence that we may employ RAM as the pricing tool.~~

~~5.2.2. Practical Considerations~~

~~In addition to the underlying market structure, statutes, regulations and other policy factors mentioned above, we consider several practical reasons in adopting RAM.~~

~~Advocates of a fixed-rate approach contend that a fixed, tariff-published rate is necessary for relatively small projects because it provides certainty for project evaluation and cost recovery. RAM provides a similar result. This is the case because a rational bidder will bid no less than its best cost estimate. Whatever it elects to bid (i.e., its cost or higher), this information gives the bidder adequate certainty to do an economic evaluation of its project.[55] If the bid is later selected, the rate is set and known over the life of the project. This process gives reasonable certainty to projects for the purposes of both initial evaluation and subsequent cash flow for cost recovery.~~

~~We also consider project cost. Projects at issue here, even if relatively small, are costly. The evidence is that each project will require investments from several million dollars to as much as $80 million or more for the largest projects.[56] It is reasonable to expect developers of these projects to undertake an economic~~

~~[55] Our adopted program does not permit price negotiation.~~

~~[56] Recurrent Pricing Reply Comments at 2. See also PG&E T&C Comments at 14 (a 10 MW wind or biomass plant could easily cost $20 million to $30 million in construction costs; absent economies of scale this is $2 million to $3 million per MW). SFUI T&C Comments at 5 (investment in excess of $7 million per MW; absent economies of scale a 20 MW project at $7 million per MW would cost $140 million). SCE T&C Reply Comments at 5-6 (installed costs of between $2,100/kW (e.g., wind) and $5,000/kW (e.g., solar) would mean installed costs per MW of $2.1 million to $5 million).~~

~~assessment.[57] We can expect these developers to either be reasonably sophisticated in financial analysis, or to hire a specialist to provide advice. Moreover, it is not unreasonable to expect developers of such projects (or the financial specialist they hire) to be comfortable with a range of input variables as part of the analysis. This is true whether the developer of the projects under consideration here (20 MW or less) is a homeowner adding a solar photovoltaic system; a dairy farmer installing a biogas digester/generator; a water company installing in-conduit hydro generation; or an independent project developer building a geothermal project, wind farm or any other RPS-eligible project. Reasonable economic assessments require a price input, but such assessments can be done with either a fixed tariff-published rate, the price the project will submit as a bid, or a range of candidate prices. Thus, we are neither persuaded by the claim that a fixed tariff-published rate is necessary for the relatively small projects here, nor that it is unreasonable to expect a project developer to be able to undertake an economic assessment using either its bid price or assumed prices for a range of variables.~~

~~[57] We have for decades employed regulatory policies and tools that rely on electricity consumers (e.g., ratepayers) making economically rational decisions. For example, we adopt rate levels, rate designs, and other policies based on this expectation (e.g., use of rate design tiers, time-of-use (TOU) rates, smart meters). We do this to give consumers relevant price signals (information) in order to make optimal investment and consumption choices. These rates often vary by only a few cents/kWh (e.g., between tiers), with resulting monthly bill variations (based on changes in consumption) of only a few dollars. Moreover, the rates (and resulting changes in monthly bills) vary over time (e.g., we do not fix ratepayer rates for 20 years; as a result, rates increase and decrease over the economic life of a ratepayer's investment). We rely on the ability of ratepayers to make economically rational decisions even with the uncertainty of future rate changes. It is no less reasonable to expect project developers to be economically rational in the face of even less uncertainty (i.e., since the RAM-determined rate is fixed, including fixed or known escalation factors when specified in the contract, over the life of the sale).~~

~~Another practical consideration identified by advocates of a fixed-price approach is the level of transaction costs. In their view, the fixed price approach minimizes transaction costs while RAM increases transaction costs. In response, others argue transaction costs under RAM are minimal. No credible estimates are presented on the cost of either approach. Absent quantitative evidence, we are left to evaluate the assertions qualitatively.~~

No party suggests that prices for this program be negotiated in the same manner as the annual RPS solicitations. We agree. We have already determined that the transaction costs of submitting bids that are subject to further negotiations is not appropriate for the smaller system-side DG market. ~~RAM opponents argue~~ Both Energy Division's RAM proposal and party comments supporting a fixed-rate FIT argue that their respective approaches will reduce transaction costs. RAM opponents assert that the cost of bid preparation can be significant, while it is zero under a fixed- price FIT. ~~We~~However, no credible estimates are presented on the cost of either approach, and we are not convinced~~. A~~ that the costs differ significantly.[25] Even with a fixed price program, a rational project developer must have some level of understanding about the economics of the project, including a price or range of prices that is likely to make the project economic. ~~This is true whether the FIT rate is or is not fixed in advance in the tariff. No party presents a compelling reason why the~~

[25] Recurrent convincingly says: "The developer resources required to bid for these projects through an auction process are a small percentage of the projects' total expense and certainly should not present an insurmountable obstacle for responsible developers, whether small or large, who are willing to make the investment and take the development risks that these projects entail." (Pricing Reply Comments at 2.)

~~cost of putting a bid on paper is significant.[58] The RAM adopted below~~The RAM adopted here does not permit negotiation over price, terms, or conditions. Under these circumstances, there is minimal cost to put a bid on paper, and no transaction cost related to price negotiation. Thus, we are not persuaded by a qualitative argument that the cost of RAM bid preparation is burdensome as compared to preparing a project for a fixed price program.

We also consider the regulatory cost of determining ~~a~~the appropriate fixed ~~rate~~price to put in a published tariff. There are costs for data collection and analysis. IOUs, parties, and staff will incur costs to participate in Commission proceedings, the outcome of which may be appealed. The time and cost of an administrative process to set a fixed price is not zero, and could be the same as or more than the sum of all bid preparation costs. Accordingly, we find that the price as bid and standard contracting aspects of RAM would reduce transaction costs for the seller, utility, and regulator.

~~5.2.3. Other Considerations~~

Next, we evaluate whether the fixed price approach and/or the market-based RAM proposal result in contract prices that are reasonable – i.e. financeable to the developer and competitive for the ratepayer. Advocates of a fixed-price approach contend that a published fixed price FIT is necessary for relatively small projects because it provides certainty for project evaluation and cost recovery, which will increase investor certainty and facilitate simpler financing. RAM provides a similar result. This is the case because a rational

---

~~[58] Recurrent convincingly says: "The developer resources required to bid for these projects through an auction process are a small percentage of the projects' total expense and certainly should not present an insurmountable obstacle for responsible developers, whether small or large, who are willing to make the investment and take the development risks that these projects entail." (Pricing Reply Comments at 2.)~~

bidder will bid no less than its best cost estimate. Whatever it elects to bid (i.e., its cost or higher), this information gives the bidder adequate certainty to do an economic evaluation of its project.[26] If the bid is later selected, the rate is set and known over the life of the project, and is reflected in a long-term contract with a creditworthy off taker. This process gives reasonable certainty to projects for the purposes of both initial evaluation and subsequent cash-flow for cost recovery.

In addition, unlike an administratively established fixed price, however, RAM also balances the ability for a small project to secure financing and attain a reasonable price, with the assurance that the ratepayer is not overpaying. Parties are concerned that a fixed price could result in ratepayer backlash if the price is set too high, as occurred in Spain and Italy.[27] We agree that there is potential for a fixed price to be set too high or too low, and either option could create financial and regulatory uncertainty. If the price is too high, it would be unreasonable for ratepayers. If it is too low, no projects would be built.

Recurrent attests to the reasonableness of a RAM mechanism for projects in the 1 ~~MW~~ to 20 MW range. Recurrent reports that it is an independent power producer successfully developing projects via auctions in this size range. Recurrent welcomes the healthy competition that an auction can stimulate and which, according to Recurrent, brings value to IOUs, ~~customers~~ratepayers, and society. In response to parties who express concern that small sellers are unduly burdened by market mechanisms, Recurrent states:

> ~~"~~As one of those ~~'~~"small sellers~~'~~" that concern these parties, Recurrent Energy categorically disagrees that competing in a RAM is unduly burdensome, unreasonably costly, or somehow

[26] Our adopted program does not permit price negotiation.

[27] TURN, Recurrent Energy, Vote Solar, and the Solar Alliance (Pricing Comments).

> unfair. … We are much more concerned by the specter of administrative price-setting gone bad, than by the need to compete through an auction process to meet our buyers' need.~~"[59]~~[28]

> Recurrent opposes a ~~cost~~ fixed price based FIT, saying that:
>
> ~~"…setting~~… [S]etting too high an energy rate (by accident or design) at the expense of utilities, ratepayers and society can result in hostility to solar development that undermines the longer-term stability of our markets.~~"[60]~~[29]

We endorse healthy competition and seek to avoid regulatory approaches that result in hostility from ratepayers or undermine long-term market stability. We also look for an approach that can quickly respond to changes in cost (both increases and decreases). Administrative determination of ~~cost (whether fixed rate or hybrid)~~contract prices is less likely to be as responsive to cost changes than is a seller determining the price it wishes to seek in ~~reasonably frequent auctions~~an auction based on its understanding of the underlying project costs, and changes in those costs.~~[61]~~

~~[59]~~[28] Recurrent Pricing Comments at 5-6.

~~[60]~~[29] Recurrent Pricing Comments at 11.

~~[61] Our experience is that market changes can outpace regulatory process. (D.85-04-075, 17 CPUC2d 521, 535.) At the same time, regulatory process, when appropriate, can be designed to update prices often (e.g., monthly, as with gas procurement charges for core customers, or short run avoided costs for QFs). We do not foreclose the use of responsive regulatory processes, but determine here for initial RAM implementation that sellers have a unique self-interest to accurately and quickly respond to cost changes. This should, if competition is effective, help bring prices down quickly (e.g., to the extent seller's costs for new RPS technologies decline, as we hope). Moreover, if competition is effective, this will happen automatically, without Commission action. Similarly, a competitive market will quickly reflect cost increases suffered by the seller (in prices bid by the seller) without Commission action.~~

~~We could use other market-based approaches (e.g., bilateral negotiations, other auction schemes). We standardize the expanded FIT as recommended by ED, however, and do not permit negotiation of prices, terms or conditions. This eliminates the use of a market-based approach based on bilateral negotiations. RAM is the market-based auction approach presented here, and we adopt it.~~

~~The risk with a market approach, however, includes the seller bidding a price far in excess of its cost. This might occur if the market is thin (e.g., few sellers) and does not place sufficient pressure on each bidder to control its price. It might also occur if one or more participants devise ways to manipulate the auction in ways we cannot now predict. We mitigate against this adverse outcome below by establishing a simplified preapproval threshold (SPT) for Tier 1 contract review.[62] This permits us to let buyers and sellers determine the price, with protection for ratepayers against an unjust and unreasonable outcome via additional Commission scrutiny of the IOU's prudence of the transaction if either our assumption about the market being competitive is incorrect, or the market is competitive but not sufficiently so.~~

~~The risk with a market approach also includes sellers succumbing to unreasonable pressures from a buyer if the market is not competitive.[63] We~~

~~[62] The SPT does not foreclose the buyer and seller agreeing to a higher price and submitting the contract for other Commission review (e.g., Tier 3 advice letter or application). The contract review in each case (via Tier 1, Tier 3, application or other Commission procedural device) would result in eliminating the need for after-the-fact reasonableness review (other than contract administration). (§ 454.5(d)(2).)~~

~~[63] Sellers may be unwilling to come to the Commission and report problems with a buyer if sellers know that the buyer can disadvantage one or more sellers who report problems when there is effectively only one (or a limited number of) buyers. In that case, the Commission may not have specific knowledge of this competitive market failure. To the extent this unequal pressure occurs, however, it reduces the~~

~~mitigate against this adverse outcome by adopting policies to maximize the potential for effective competition (e.g., below we permit sales in any service territory to increase the number of buyers and the competition between buyers). We also adopt monitoring and periodic review of RAM results to permit modifications, if necessary. This allows us to let buyers and sellers determine the price, with protections for all stakeholders against bad outcomes if the market is not sufficiently competitive.~~

~~5.3. Conclusion~~

~~We adopt a RAM market-based approach relying on policy, practical, and other considerations enumerated above. We next turn to questions of jurisdiction.~~

~~6. Jurisdiction~~

~~There is no dispute among parties that the Commission may order IOUs to file a FIT. Positions vary on Commission jurisdiction to set the FIT rate. The range of views is essentially from no jurisdiction to complete jurisdiction, with a middle ground that elements of jurisdiction reside with the FERC but that several aspects reside with the state. Some parties with the middle ground view suggest the Commission seek FERC approval of a Commission-established FIT rate to overcome any ambiguity regarding Commission~~

By allowing developers to bid in their price and also eliminating further price negotiations, the RAM appropriately balances the goals of maintaining a competitive market and reducing transaction costs for small renewable projects. We note that experience to date in the California Solar Initiative, as well as SCE's Solar Photovoltaic Program and the Renewables Standard Contract (RSC)

~~give-and-take the Commission relies upon to produce economically optimal, just and reasonable outcomes that can otherwise result from effective and vigorous competition.~~

program suggests that the market for smaller scale projects appears robust with a significant number of competing sellers. However, as discussed later, we adopt necessary safeguards to protect stakeholders from adverse outcomes in case the market is not sufficiently competitive to reach optimal results. Those safeguards include a cap on total program capacity that can be submitted for simplified contract review, IOU discretion to procure less than the authorized cap in instances of market manipulation or uncompetitive pricing, and ongoing monitoring and reporting. Additionally, the Commission retains discretion to reject contracts submitted for its consideration pursuant to this program if they are not found to be in ratepayers interests.

4.3.2. Jurisdictional Considerations

When commenting on contractual terms and conditions, a number of parties opined that the Commission has no jurisdiction to establish ~~the rate.~~

~~6.1. **Summary of Positions**~~

~~We briefly summarize the positions of parties.~~

~~IOUs and some parties argue that the Commission has no jurisdiction to set a FIT rate because FERC has exclusive jurisdiction over sales of electric energy in wholesale transactions, including exclusive authority to set rates for wholesale sales. The only exception, according to these parties, is that the Commission may set the rate for utility purchases of electricity from QFs at the buying utility's avoided cost, pursuant to~~a fixed rate FIT. By ruling dated May 28, 2009, parties were directed to file briefs on this legal issue. In summary, there is significant dispute among the parties regarding the Commission's jurisdiction to set a fixed price FIT. There is, however, no dispute that the Commission has jurisdiction to set prices at avoided cost for IOU purchases from qualifying facilities (QFs) pursuant to § 210 of the Public Utility Regulatory Policies Act ~~of~~

~~1978 (PURPA) and FERC regulations. Parties with this view assert that the rate must be based on consideration of all (not a subset of) resources, and is strictly limited to avoided cost, as defined by federal statute and FERC regulations.~~

~~DRA and other parties contend the Commission has complete authority to set the FIT rate because the FIT does not set the wholesale rate at which the generator must sell. Rather, a FIT is a standard tariff that requires an IOU to make certain purchases, but the generator has discretion to sell or not sell at that or any other rate. Some parties with this view also contend that these are intrastate sales by state-created load serving entities (LSEs) at the distribution level for transactions that are not in interstate commerce and, as a result, these sales are not within federal jurisdiction.~~

~~The California AG and others assert the Commission has jurisdiction to set the FIT rate. The AG says the Commission may do so for QFs at avoided cost, for example, and the Commission has considerable discretion in its determination of avoided cost. According to the AG, determination of avoided cost no longer requires a solicitation from all sources, and incremental energy increasingly does not come from fossil-fuel based generation. The AG explains that this is due to constraints created by RPS portfolio requirements and climate change laws. The RPS solicitation, as a result, may specifically be for electricity generated by renewable resources, and may potentially be by technology. The AG also asserts that renewable energy credits (RECs) may be used as a component of the FIT, for either QFs or non-QFs, to meet RPS portfolio requirements, climate change mandates, and encourage generators to sell to the grid. GPI and Sustainable Conservation characterize this approach as including green adders with the avoided cost rate.~~

SA, VSI and others with a middle ground view assert FERC has jurisdiction over wholesale sales but the Commission has authority to do several related things. These things include setting FIT rates at avoided cost, establishing IOU procurement practices (including resource-specific procurement targets), regulating the sale of RECs, and determining tariff treatment of distribution costs and benefits. The FIT rate, according to this view, may include avoided transmission and distribution line losses and congestion costs, avoided or deferred investment in transmission and distribution upgrades, avoided environmental costs, and avoided RPS non-compliance penalties. FCE and CALSEIA characterize this view by saying FERC has jurisdiction over electricity, capacity and ancillary services for wholesale transactions, but the state has plenary authority over any product or attribute in wholesale transactions other than electricity, capacity or ancillary services. These other things may include encouraging renewables via RECs, treatment of GHGs, technology-specific incentives,[64] tax structure and direct subsidies. CAC and EPUC assert the Commission may set the FIT rate using either a market approach or a cost basis but, under either approach, they propose that the Commission seek FERC approval to remove the possibility of a utility challenge.

6.2. **FERC**

We briefly summarize FERC's regulation of wholesale markets in order to place the jurisdiction discussion in context.

FERC regulates sales of electricity in wholesale markets under several statutes, including the Federal Power Act (FPA) and PURPA. The statutory

[64] As examples, FCE and CalSEIA cite incentive payments pursuant to the SGIP and the CSI Program.

~~requirements are that rates must be just, reasonable, and not unduly discriminatory. FERC fundamentally does this in one of two ways.~~

~~First, in markets that are not competitive, FERC uses cost of service. These are markets in which either the seller or buyer has some unacceptable degree of market power. In most noncompetitive markets, FERC sets the just and reasonable rate equal to the cost of the seller. This approach is used in monopoly (single seller) markets. In some noncompetitive markets, FERC sets the just and reasonable rate in relationship to the cost of the buyer (i.e., the cost the buyer would incur absent certain conditions). This approach is used in monopsony (single buyer) markets. In the case of the QF market, the rate (with some exceptions) is set equal to the cost the buyer would have incurred but for the purchase from the QF. PURPA and FERC regulations authorize determination of the buyer's avoided cost by state commissions.~~

~~Second, in markets that are competitive, FERC permits market-based rates. Each seller submits a technical study showing it has no market power. In the absence of market power, FERC gives approval for the seller to enter into contracts at any price to which the buyer and seller agree. Sellers in this market are not subject to cost of service regulation, and the market-based rate is determined by FERC to be just, reasonable and not unduly discriminatory. The seller files the contract, including applicable rates, with FERC. These sellers are sometimes referred to as independent power producers.~~

~~6.3. QFs~~

~~There is no dispute that we have jurisdiction to set prices for IOU purchases from QFs. One approach for an expanded FIT here would be to~~

~~require that the FIT be~~(PURPA.).[30] Further, there is no dispute that the Commission has jurisdiction to rely on a market-based mechanism to set prices. Thus, to avoid this legal dispute and implement a new procurement mechanism as quickly and efficiently as possible, the Commission may either comply with PURPA and establish an avoided cost price, or it may adopt a market-based approach. If it pursues the first option, the Commission could develop a fixed price tariff applicable to QFs at avoided cost, and implement the recommendations of the ~~AG~~attorney general and others to update avoided costs for new market conditions and additional factors. ~~We decline to do so, however, because we already have a program for QFs. Changes and updates to the QF program and avoided costs for QFs should be made in a QF and/or avoided cost proceeding, not here.~~

~~Further, the statute provides that the RPS program does not constitute implementation of the QF program.[65] The legislature could have combined the two programs but did not. We apply reasonable harmony between the two programs to facilitate stakeholder and program efficiencies, but do not treat them as one program.~~

~~Thus, the RPS program is not the QF program. While there is considerable overlap, there are also differences. We have thus far considered them separately, and continue to do so here.~~

---

[30] 16 U.S.C. § 824a-3 (2006); *see generally* 16 U.S.C. § 2601 *et seq.* (2006).. This authority was most recently affirmed in Order on Petitions for Declaratory Order, 132 FERC ¶ 61,047 (July 15, 2010).

~~[65] "The establishment of a renewables portfolio standard shall not constitute implementation by the commission of the federal Public Utility Regulatory Policies Act of 1978 (Public Law 95-617)." (§ 399.15(e).)~~

~~6.4. RAM~~

~~We do not set the rate here for projects up to 20 MW by relying on our QF program. We must, therefore, still consider jurisdiction.~~

~~For policy, pragmatic and other reasons explained above, we adopt the market-based RAM recommended by ED. RAM, as parties explain, avoids or eliminates the jurisdictional issue.~~

~~For example,~~ PG&E and several parties assert that RAM avoids the jurisdiction question. PG&E ~~says~~states:

> ~~"~~The proposed auction process would resolve the issue parties briefed previously in this proceeding; namely, whether the Commission has authority to establish prices for wholesale energy sales in interstate commerce … The RAM, by employing a competitive solicitation, should yield market-based prices and avoid the issue of Commission jurisdiction to set prices in the wholesale generation market.~~"~~[66]~~[31]

SCE says the Commission's authority is to set FIT prices either (a) at avoided costs for QFs or (b) to "use a market-based pricing structure."~~[67]~~[32] SCE describes RAM as providing "a competitive, market-based mechanism which appropriately looks to the market for pricing."~~[68]~~[33]

IEP points out that we have for several years required IOUs to undertake competitive solicitations to procure conventional and renewable resources. The results do not conflict with ~~FERC's~~the Federal Energy Regulatory Commission's

~~[66]~~[31] PG&E Pricing Comments at 4.

~~[67]~~[32] SCE Pricing Comments at 4.

~~[68]~~[33] SCE Pricing Comments at 6.

(FERC) jurisdiction, according to IEP, precisely because the solicitations produce market-based prices.[69][34] IEP concludes:

> "…no conflict with FERC's jurisdiction is created if the Commission requires or encourages the utilities to pursue competitive solicitations for specific products. In this approach, the Commission acts within its jurisdiction by requiring or encouraging a competitive approach to the products that might be the focus of a feed-in tariff and by accepting the market-based prices that result from that competitive procurement. The resulting prices are just and reasonable and are authorized by FERC through its market-based rate authority."[70][35]

These We agree with these parties are right. Under RAM does we do not result in our setting set the price, but relies rely on a market-mechanism that is compatible with FERC's rate-setting in wholesale markets. RAM avoids or eliminates the jurisdictional issue, and we adopt it, in part, for precisely this reason.

The reasonableness of this approach, however, relies on a critical assumption: the market is— and remains— sufficiently competitive to produce just and reasonable rates, result in efficient and optimal outcomes, and protect both buyers and, sellers, and ratepayers. We address competitive aspects of the market below when we discuss Commission oversight of the RAM program and appropriate ratepayer protection mechanisms. First, we address details of program design.

5. Must-Take Requirement

The Existing FIT is a must-take obligation based on a first-come first-served basis at a known price (MPR) up to a program limit. It includes a

[69][34] IEP Reply Brief at 4.

[70][35] IEP Reply Brief at 4.

wait-list for additionally interested developers. ED's original proposal would require each IOU to have an auction soliciting projects up to 10 MW for up to 1,000 MW, and allow IOUs to solicit projects from 10 to 20 MW.[36] ED's proposal recommended that the total cost of procurement for projects up to 10 MW would be limited by a revenue requirement cap, so that utilities must accept all bids for projects up to 10 MW, starting with least cost projects first, until the revenue requirement cap or capacity cap is exhausted, whichever comes first.[37] All other procurement would be voluntary.

The proposed decision would have required the utilities to solicit eligible projects up to 20 MW and accept all bids offered through RAM up to a pre-established price and a capacity cap. Parties dispute the legality of this approach based on both federal and state law.[38] The federal law issue is rendered moot in

---

[36] March 2009 Proposal at 5.

[37] August 2009 Proposal at 8.

[38] PG&E, SCE, and SDGE assert that a requirement to procure all bids up to a pre-established price set at the market price referent plus a 50% premium violates state and federal law. They argue that it violates state law (Pub. Util. Code Section 399.15[d]) which sets a limitation on the IOUs' obligation to procure renewable energy at above-MPR costs. They also argue that it violates federal law because it would require them to purchase power at a rate above avoided cost.

FIT Coalition, Vote Solar, Solar Alliance and IEP oppose the IOUs' arguments about the legality of the proposed decision. For example, Vote Solar opposes the IOUs' arguments about state law and contends that the IOUs' arguments are based on the erroneous assumption that RAM prices will exceed the MPR. IEP states that the proposed decision does not violate federal law because it would only set targets for the IOUs' procurement of specific products and the contract prices would be determined through a market mechanism.

We disagree with the IOUs' contention that the RAM violates state law. The limitation imposed by Pub. Util. Code Section 399.15(d) on procurement of energy used for RPS compliance at prices above the MPR applies to contracts selected through the IOUs' annual RPS solicitations. *See* Pub. Util. Code Section 399.15(d)(2)(A). State law,

this decision because we preserve the IOUs' discretion to reject bids in instances of market manipulation or non-competitive pricing compared to other renewable procurement opportunities. See Section 6.3 for details on project bid selection.

6. Utility Applicability

ED proposes limiting RAM to the three largest IOUs. We agree.

In comments to the Proposed Decision, SCE and SDGE argue that they should be able to separately design and offer their own procurement programs that target the same market sector, instead of using RAM. SCE also suggests that all megawatts procured through its RSC program should draw down on its RAM capacity requirement.

We agree in part. RAM is the Commission's preferred approach for pursuing projects in the 1 to 20 MW size range for all the reasons already stated. As Vote Solar notes, allowing the utilities unlimited discretion in designing their own, utility specific programs poses certain challenges to both independent power producers (IPPs) and the Commission.[39] IPPs must contend with potentially substantial differences in eligibility requirements and contracting terms that were not developed through a transparent Commission proceeding, and the Commission then must evaluate the resulting contracts that have not been substantially vetted to ensure the contracts and underlying projects are sufficiently viable to merit approval. By adopting RAM, we create a program that provides greater consistency and embodies program rules and contracting terms that facilitate relatively quick review via a Tier 2 advice letter. Accordingly, in the interest of promoting competition and streamlining of the administrative

---

however, does not preclude the Commission from using other mechanisms to ensure compliance with California's RPS requirements.

[39] Comments on Proposed Decision at 3.

process, the utilities should pursue this market segment specifically via RAM. In other words, while IOUs may use RAM, annual RPS solicitations, or Commission-approved solar photovoltaic programs to procure system-side DG projects up to 20 MW, they may no longer use bilateral negotiations or voluntary programs like SCE's RSC.

Nonetheless, we recognize that SCE has recently executed contracts through its RSC program.[40] In the interest of market continuity, SCE may count any of these contracts approved by the Commission towards its capacity cap.[41] See Section 7.1 for details on how SCE can count contracts already executed through SCE's 2010 RSC to SCE's capacity cap. Furthermore, SCE may submit additional contracts resulting from the RSC solicitations that have been conducted to date, however other than those contracts executed as of the effective date of this decision, these contracts will not reduce SCE's obligations under RAM.

SCE, TURN, and Redwood Renewables also argue that the RAM program should apply to all CPUC-jurisdictional load-serving entities (LSEs). Additionally, § 365.1(c)(1) requires the Commission to ensure that "other providers" (which do not include community choice aggregators) are subject to the same requirements applicable to the three largest IOUs that are implemented pursuant to the Commission authority under the RPS program.

Notwithstanding the arguments that the RAM program should apply to all CPUC-jurisdictional LSEs, we will not apply RAM to CPUC jurisdictional LSEs

---

[40] SCE's press release (November 19, 2010) reports that it has executed 21 contracts for nearly 259 MW from its 2010 RSC program. See http://www.edison.com/pressroom/pr.asp?bu=&year=0&id=7502

[41] We note that these projects are subject to a Tier 3 review process, and the Commission reserves the right to approve or reject those projects based on their merits.

beyond the IOUs. We apply fundamental RPS program basics to all LSEs (e.g., targets, reporting, penalties), including not only the largest IOUs, but also small and multi-jurisdictional utilities (SMJUs), community choice aggregators (CCAs), and electric service providers. We are considering expansion of these requirements to electric service providers (ESPs) pursuant to PU Code § 365.1(c)(1).[42] In consideration of that expansion, we recognize that Commission requirements regarding specific RPS program elements necessarily vary among LSEs based on the Commission's regulatory authority, responsibilities, and duties with regard to each type of LSE.[43]

With these distinctions in mind, we limit RAM to the three largest IOUs. As CCAs are expressly exempted by § 365.1(c (1), and they have not had an opportunity to comment here, we decline to apply any RAM requirements to CCAs. It would also be inappropriate to apply the RAM to ESPs for different reasons. The Commission has no regulatory authority over ESP contracting processes. Such authority extends from the Commission's regulatory rate authority over IOUs, and serves no purpose with regard to ESP contracts since the Commission has no regulatory rate authority over ESPs. In addition, because the ESPs do not submit their contracts to us for approval, and a key benefit and objective of RAM as a procurement vehicle is to provide streamlined contract approval for projects that conform to the RAM eligibility requirements, it is not relevant to the ESPs.

---

[42] SB 695 (Kehoe), Stats. 2009, ch. 337. Section 365.1(c)(1) directs the Commission to "ensure that other providers are subject to the same requirements that are applicable to the state's three largest electrical corporations…" The provision was triggered upon issuance of D.10-03-022 on March 15, 2010. Pursuant to a Ruling dated March 25, 2010, parties have filed briefs and reply briefs, and a proposed decision is being prepared.

[43] See, for example, D.05-11-025, D.06-10-019, D.08-05-029.

We also do not impose the RAM requirement on SMJUs. SMJUs are not addressed in § 365.1. Further, application of the RAM to SMJUs is impractical given their size. PacifiCorp, the largest SMJU, has been allocated 0.405% (less than one-half of one percent) in the Existing FIT program.[44] The total allocation to the four SMJUs combined is 0.599% (less than six-tenths of one percent).[45] Allocation to PacifiCorp (the largest of the four SMJUs) of its share of the 1,000 MW RAM total program adopted here would be about 4 MW (and to all four of the SMJUs would be about 6 MW). PacifiCorp would be allocated about 1 MW (and all four SMJUs would be allocated about 1.5 MW) in each of the four auctions adopted above. We are not persuaded that, as a practical matter, it is rational to apply the RAM program (up to 20 MW per transaction) to each SMJU with allocated shares of 4 MW or less for the total program (and 1 MW or less per auction). We employed this same practical consideration in 2007 when we limited the required FIT offering by the SMJUs in the Existing FIT to 1 MW rather than 1.5 MW. (See D.07-07-027 at 26.) We do so again here.

7. ~~Program~~Auction Design

Having decided above to ~~extend FIT eligibility~~adopt a simplified and standardized contracting program for renewable system-side DG up to 20 MW in the form of RAM and employ an auction mechanism for determining contract price~~ determination~~, we next consider specific ~~program~~auction design elements. These include a ~~maximum program cap, eligibility requirements, uniformity of terms and conditions, negotiations, and project viability criteria.~~

[44] 1,013 kW divided by 250,000 kW is 0.405%. (See D.07-07-027 at 9.)

[45] 1,497 kW divided by 250,000 kW is 0.599%. (*Id.*)

~~7.1. **Goals**~~

~~The adopted design elements are influenced by the goals of FIT expansion. The overall goals are: the provision of safe and reliable service to satisfy demand without shortage or surplus at just and reasonable rates; economic efficiency; equity among all stakeholders; and optimal resource mix and use consistent with RPS, climate and other state and national statutes and goals. Particular goals for the expanded FIT (to the extent feasible within the policy framework of a competitive structure) are reasonable simplicity, ease of administration and transparency.~~

~~In pursuit of these goals, we begin with FIT (existing). We also consider making the RAM program as parallel as possible with other existing programs (e.g., RPS annual bid solicitations, QF program, voluntary programs of IOUs). We take the best of each program, to the extent reasonable, using lessons learned from other programs, and our experience of over 30 years procuring electricity from non-utility sources. We need not be more specific or resolve other differences of opinion among parties with respect to the goals. Rather, this context gives sufficient guidance to allow determination of necessary elements below.~~ program capacity authorization, number of auctions per year, project selection criteria, and a simplified contract review process.

7.1. ~~7.2.~~ Program ~~Cap~~Capacity Authorization

~~7.2.1. **Proposal**~~

7.1.1. Background

~~ED proposes FIT program expansion differentiated between (a) projects up to 10 MW and (b) projects between 10 and 20 MW. For projects up to 10 MW, ED initially proposed a program cap of 1,000 MW allocated to the three largest IOUs. As further developed in its August 2009 paper, ED recommends the program cap~~

~~be based on~~In its August 2009 Pricing Proposal, Energy Division suggests that the procurement authorized for the RAM program be capped by a revenue requirement~~, allocated yearly or every two years, equivalent to approximately 1,000 MW. According to ED, this provides a program cap that is both a cost-containment and a cost-minimization mechanism. ED says it provides streamlined, pre-approved cost recovery for IOUs; cost certainty for ratepayers; and regulatory certainty for the market. ED proposes that the revenue requirement cap in the future be based on a utility's need for the products solicited. Since the methodology will~~.[46] A revenue requirement, or a total program cost cap, would be calculated for each IOU to reflect how much renewable system-side DG each utility needs to procure compared to other renewable procurement strategies. The amount of RAM procurement needed and its associated cost would be based on an evaluation of cost, development risk profile, and development timeframe of each procurement strategy. Since the revenue requirement would reflect the types and costs of resources needed by the utility, it would be reasonable for all RAM contracts signed within that cap to be given a streamlined contract review.

Since it would take some time to ~~develop and roll into RPS~~implement a methodology to determine IOU renewable DG procurement need, and it must be coordinated with other aspects of IOU procurement planning, ~~however, ED recommends~~the ED's proposal offers that an interim revenue requirement cap ~~equivalent to approximately 1,000 MW allocated proportionately among the three IOUs over the next four years. Some parties proposed, at ED's request, a~~

[46] Pricing Proposal at 8

~~methodology to calculate the interim revenue requirement, along with examples.~~[71] reflects an estimated cost of 1,000 MW of RAM procurement over four years.

7.1.2. Party Comments

Several parties support the revenue requirement approach.[72][47] Two parties oppose the approach.[73][48] SCE and Vote Solar propose methodologies for calculating a revenue requirement. SCE's recommended approach would use the MPR multiplied by the energy solicited for a particular auction (assuming an average capacity factor for California's renewable energy mix). Vote Solar suggests that the revenue requirement be calculated based on the costs of a proxy technology for each auction, using publicly available information about the cost of that technology (e.g. data from the Renewable Energy Transmission Initiative), multiplied by the energy in MWhs solicited for in a particular auction.

~~7.2.2. **Revenue Requirement Cap**~~

~~We adopt a relatively simple total capacity cap of 1,000 MW for the reasons explained below, and decline to adopt a more complex revenue requirement cap. The current revenue requirement proposal is not yet sufficiently concrete, and we need a more complete understanding of the mechanics, advantages, disadvantages and implications before its adoption.~~[74]

~~[71] See, for example, SCE Pricing Comments at 12; VSI Pricing Comments at 11; SA Pricing Comments at 26.~~

[72][47] CALSEIA, Recurrent, ~~SA~~Solar Alliance, Vote Solar, TURN, ~~VSI.~~

[73][48] DRA, ~~FS~~First Solar.

~~[74] Some parties provided example calculations at ED's request. These examples show annual revenue requirement caps that range from $60 million (for 250 MW) to $896 million (for 2,000 MW). Before adopting a revenue requirement cap, we need a detailed calculation that is more fully vetted. We also need an analysis of the gaming~~

~~The revenue requirement examples use a range of variables. For example, one calculation derives a revenue requirement from maximum energy deliveries at an applicable MPR.[75] Other calculations rely on a mix of projects (which meet various criteria), capacity factor and project cost.[76] A revenue requirement determination either requires evidence on these variables, or the making of various assumptions. Parties may legitimately dispute these and other variables, along with the relevant values, but did not sufficiently do so here for us to reasonably adopt an interim revenue requirement cap.~~

~~Moreover, the range of final selected variables would, under ED's proposal, involve pre-approval of cost recovery for hundreds of millions of dollars, in which IOUs, ratepayers and other stakeholders will have substantial interest. The variables involve potentially disputed issues of material fact. There is too much complexity, uncertainty and risk of litigation to follow this path now.~~

~~We agree with DRA that:~~

~~opportunities that might lead to excessively high prices, along with proposed mitigation options.~~

~~[75] SCE's example is: $60 million annual revenue requirement based on 250 MW*25% capacity factor*8760 hours*$110/mWh. (Pricing Comments at 12.) The variables include capacity factor and applicable MPR (e.g., start date and contract duration, which relate to assumptions about projects and contracts).~~

~~[76] CALSEIA's example is: $165 million to $465 million annual revenue requirement based on project mix, project output and project cost. (Pricing Comments at 7.) SA's example is: $896 million annual revenue requirement based on a mix of renewable projects (75% of which are peaking as-available solar) using staff-based cost estimates. (Pricing Comments at 26.) VSI does not present an example and believes details are best worked out at a workshop, but suggests a revenue requirement based on an ED staff-identified proxy technology for each renewable product category selected by using several criteria (e.g., technology must be (a) commercialized, (b) least-cost in its category and (c) capable of scalability to meet program demands). (Pricing Comments at 11.) These three examples use variables that include project mix, project cost, project output, and project criteria.~~

> "The revenue requirement approach introduces unnecessary complexities into the RAM process and requires that long-term assumptions be made about the capacity factor of the winning bidders in order to determine where to draw the line. Such assumptions may pave the way for protests by losing bidders that the line has been drawn too low. The revenue requirement concept, while innovative, will complicate the determination of how many bids should be accepted, because estimating the costs of a renewable contract over a 20 year lifespan, or even in the year it comes online, is speculative."[77]

We are also concerned that the proposed revenue requirement approach (in conjunction with ED's proposed must-take obligation for projects up to 10 MW) fails to adequately protect against unreasonably high prices. This could occur, for example, if the response to RAM is low. Bidders may have an inclination (or take the risk) that the number of bidders (supply) may be low relative to the program cap (demand). If so, each bidder may submit a bid substantially above its cost on the chance that the bid must be accepted. While a revenue requirement limit would cap the total cost of the program, no evidence in this record demonstrates that a revenue requirement cap will sufficiently protect ratepayers against the risk of too few projects being selected at too high a price.[78]

---

[77] Pricing Comments at 10.

[78] ED proposes that this protection be provided by adoption of other program requirements, such as a minimum seller concentration ratio (e.g., no one seller can contract for more than 50% of the auction cap). We address this below when we discuss Market Elements. We conclude that this approach introduces complexities that are unlikely to provide reasonable offsetting protections. Moreover, no examples are provided that show results over a range of assumed variables (e.g., concentration ratios, sales, revenue requirement cap) to demonstrate the resulting prices are just and reasonable.

~~7.2.3. **Capacity Cap**~~

Several parties provide alternatives to a revenue requirement. Both DRAand First Solar propose a hard megawatt capacity cap instead of a revenue requirement. DRA argues that a revenue requirement, while an innovative approach, would be too complex to calculate at this time.[49] First Solar asserts that a firm capacity cap provides more market certainty, and suggests 3,000 MW.[50]

In response to ED's proposed 1,000 MW cap, Solar Alliance, Sierra Club, First Solar, FIT Coalition, LA Community College District, Vote Solar and others argue for a higher or no cap. For example, Solar Alliance recommends a cap of 2,000 MW; Sierra Club recommends 3,000 MW (with all FIT contracts included); FIT Coalition recommends 4,000 MW (with a minimum of 1,000 MW auctioned per year); LA Community College District and Vote Solar recommend no cap (i.e. unlimited).

7.1.3. Discussion

~~In the absence of a revenue requirement cap we agree with DRA and adopt a nameplate capacity cap.[79] We adopt~~We adopt an interim capacity authorization of 1,000 MW, and allocate this to the three ~~affected~~large IOUs using the same allocation used now for the ~~program up to 1.5 MW~~Existing FIT, as shown in ~~more detail~~Table 1 below. We do this in light of the following considerations.

SCE argues that no cap can be determined in the absence of prices and other variables. We ~~disagree. A total capacity (MW) cap provides a measure of~~

[49] Pricing Comments at 10.

[50] Pricing Comments at 8.

~~[79] Pricing Comments at 16.~~

~~risk mitigation against an overly successful program. Absent a total cap of 1,000 MW, for example, subscription might reach several times that amount before RAM can be suspended.[80] Alternatively, if too many contracts are signed and submitted to the Commission by the advice letter procedure adopted below, the Commission, in the absence of a predetermined total program cap, might be required to suspend and reject numerous advice letters, even after the IOU and bidder have spent precious time and resources to consummate a contract. A better approach is one that is controlled and incremental, allowing testing of this program expansion with paced growth based on experience and need. We do that via a reasonable total capacity cap~~agree that in the long-term we should authorize a capacity amount based on a utility's need for the product and relative costs of the viable alternatives, as recommended by Energy Division's revenue requirement proposal. However, at this time this methodology is not in place and we therefore find that an initial 1,000 MW procurement requirement is reasonable. It provides an adequate quantity to test the program and mitigates against potential adverse outcomes if the program needs adjustment.

~~DRA argues the cap should be reduced to 500 MW given both the increase to the FIT program cap by SB 32 and a desire to cap the cost of the program.[81] We disagree. The cap under SB 32 includes municipal utilities. Preliminary indications are that the amount to be allocated to IOUs is about the same as is allocated now. Further, parties present no convincing data on an optimal total program cost cap. We adopt later in this order a simplified preapproval~~

~~[80] The QF program produced more subscriptions than expected before the Commission was able to suspend certain standard offers. (See, for example, D.85-07-021, 18 CPUC2d 315 and D.86-05-024, 21 CPUC 2d 124 cited in D.07-09-040 in footnote 29 at 15.)~~

~~[81] Pricing Comments at 9-10.~~

~~threshold (SPT) for streamlined contract review, thereby facilitating the essential cost containment goal without also necessitating a reduction in the capacity cap.~~

SDG&E asserts that the cap should be 1,000 MW allocated to each IOU, but further limited by an IOU's RPS targets. That is, an IOU should be able to suspend its RAM when its RPS program target is reached. We disagree. RPS program targets are minimums, not maximums. Twenty percent by 2010 is the minimum. An IOU may not procure less than 20% without the potential for penalty, but may procure more than 20% without penalty. Moreover, the risk of over-procurement given the amount of allocated RAM MW is minor (e.g., 81 MW allocated to SDG&E).~~82~~51 If over-procurement becomes a serious risk, IOUs may slightly reduce new contracts selected pursuant to the annual solicitation~~, voluntary,~~ or other programs ~~which~~that do not have specific allocated capacity at this time. We seek relative simplicity here, and capping the program at 1,000 MW subject to further reductions ~~adds~~would add unnecessary ~~potential~~ confusion and complexity.

~~SA, Sierra Club California, FSI, FITC, LACCD, VSI and others argue for a higher or no cap. For example, SA recommends a cap of 2,000 MW; Sierra Club California recommends 3,000 MW (with all FIT contracts included); FSI recommends 3,000 MW; FITC recommends 4,000 MW (with a minimum of 1,000 MW auctioned per year); LACCD and VSI recommend no cap.~~

~~82~~ 51 SDG&E has voluntarily committed to 33% by 2020. (D.08-12-058 at 265). In approving the Sunrise Powerlink Transmission Project, we said we do not take this commitment lightly, and fully expect SDG&E to follow though. ~~(~~(Id.) SDG&E is concerned with the quantity and cost of over-procurement, absent the ability to suspend RAM when its RPS program targets are reached. Given its commitment to 33%, SDG&E's concern is misplaced.

~~We decline to adopt a higher cap or no cap. We may adjust our 1,000 MW cap at any time based on evidence of response and need. An initial cap of 1,000 MW is reasonable. It provides an adequate quantity to test the adopted program expansion while mitigating against adverse outcomes if the program needs adjustment. We may later remove the cap entirely if experience with the program demonstrates that the market itself successfully reaches an optimal outcome~~Parties provide a variety of recommendations on the appropriate cap level, from an unlimited authorization, to support of ED's 1,000 MW proposal. We have had mixed experience with uncapped programs~~, however,~~ and decline to adopt this expansion without a program limit, at least before we have some evidence of the results.[83] ~~One lesson from our experience is not to be pure ideologues but to be responsible pragmatists. GPI convincingly says:~~ We decline to adopt a higher cap or no cap. The 1,000 MW cap allocated to three IOUs is sufficiently large to provide market opportunities, while being sufficiently small to provide protection against bad outcomes. In the absence of a revenue requirement cap, we agree with DRA and First Solar and adopt a nameplate capacity cap of 1,000 MW to be procured between the IOUs over the next two years. We may adjust our 1,000 MW cap at any time based on evidence of response and need.

> ~~"Given the fact that renewable energy markets currently are not in a state of competitive equilibrium, and are not likely to become so in the foreseeable future, it seems to us that prudent policy prescriptions should be designed around the markets as they~~

---

[83] ~~For example, the QF market began in the 1980s without a MW cap, and by about 1985 resulted in contracts for more capacity than some believed was needed. The Commission responded to these and other concerns by suspending certain standard offers. Market restructuring began in the late 1990s without effective caps on market results, and by the early 2000s California suffered a loss of several billion dollars.~~

~~actually are, not the idealized competitive markets that we might wish we had."[84]~~

~~7.2.4. **Cap Adjustment**~~

~~There is no dispute about maintaining the option to update the adopted program cap. The issue is the proceeding in which that might occur. ED recommends that the cap be adjusted in either an annual RPS procurement plan proceeding or LTPP proceeding. Some parties assert that all adjustments should be in an LTPP proceeding, where a comprehensive examination of procurement will take place.~~

~~We do not limit possible updates to an LTPP proceeding. The adopted program parameters (MW and SPT) and any other program elements adopted here may be adjusted in any appropriate proceeding (e.g., annual RPS, LTPP) based on any and all relevant factors (e.g., need, cost, rate effects, reliability issues, resource mix goals, GHG goals). We intend all resource and procurement issues to eventually be in one periodic LTPP proceeding, including the FIT, FIT adjustments, RAM, and all other RPS matters. This may or may not occur by the time an adjustment is necessary in some aspect of the adopted RAM.~~

~~7.2.5.~~

If an IOU would like to procure more than its allocated share of the 1,000 MW cap, it may request an increase in its implementation advice letter. If approved by the Commission, the additional capacity can be submitted via the streamlined Tier 2 advice letter process. In addition, we expect the 1,000 MW to be only an initial authorization. After the first authorization is expired, it makes sense to authorize RAM procurement based on a more informed evaluation of a utility's need. While the inputs and methodology are not in place to adopt a

~~[84] Pricing Comments at 4.~~

revenue requirement cap at this time, we authorize the Director of Energy Division to explore methodologies for aligning RAM procurement authority with the Commission's procurement planning process.

In addition, at any time, the Director of Energy Division may issue a resolution, either on its own motion or in response to a utility advice letter filing to update the cap. A utility advice letter request would need to justify the cap adjustment.

7.1.4. Capacity Allocation

~~The~~We ~~apply RAM to the three largest IOUs for reasons explained below under Eligibility. We use the same allocation to these IOUs that we used for the initial program.~~ adopt the same allocation ~~is~~percentages used for the Existing FIT to allocate the 1,000 MW capacity cap as follows:

TABLE 1

TOTAL PROGRAM CAPACITY ALLOCATION

UTILITY	INITIAL ALLOCATION (MW)~~[1]~~[52]	PERCENT OF INITIAL ALLOCATION	EXPANDED ALLOCATION (MW)
SCE	247.7	49.84	498.4
PG&E	209.2	42.09	420.9
SDG&E	40.1	8.07	80.7
TOTAL	497.0	100.00	1,000.0

~~[1] This is the total initial FIT allocation (e.g., the sum of the allocation for water/wastewater and other) found in D.07-07-027 at 9, as expanded for SDG&E in D.08-09-033. The four small and multi-jurisdictional utilities (SMJUs) in the statewide total of 498 MW are not included here. (See Background discussion above.)~~

~~These individual allocations may be updated as needed by an IOU using the same approach already adopted for the existing FIT program (e.g., data collection and allocation with support from CEC, advice letter or other pleading filed with the Commission). (See D.07-07-027 at 10.)~~

ED recommends that the program cap be allocated to IOUs over four years.~~[85]~~[53] We decline to adopt a four-year horizon for this program~~. The 1,000 MW cap allocated to three IOUs is sufficiently large to provide market opportunities, while being sufficiently small to provide protection against bad outcomes. We need not further distribute the 1,000 MW to four years~~.

[52] This is the total initial Existing FIT allocation (e.g., the sum of the allocation for water/wastewater and other) found in D.07-07-027 at 9, as expanded for SDG&E in D.08-09-033. The four small and multi-jurisdictional utilities (SMJUs) in the statewide total of 498 MW are not included here. (See Background discussion above.)

~~[85] August 2009~~[53] Pricing Proposal at 8.

Nonetheless, we are concerned about the degree of competition and take reasonable steps to increase the ~~competitiveness~~competitive environment in which RAM will operate. ~~The competitiveness of each auction can be increased by reducing demand (all else equal, such as the same amount of supply). We have, for several reasons, controlled demand in two recently authorized solar PV programs. (See D.09-06-049 for SCE and D.10-04-052 for PG&E.) We do so here to mitigate against concerns that the market will not be sufficiently competitive. This device also has the beneficial effect of limiting RAM program costs in any one year as we gain experience.[86]~~

Therefore, ~~we require that no one~~each RAM auction ~~include (either solicit for or~~shall result in contracts ~~of) more than~~for 25% of the total allocation[54]:

TABLE 2
TOTAL ALLOCATION PER AUCTION

UTILITY	TOTAL RAM ALLOCATION	ALLOCATION FOR EACH RAM AUCTION
SCE	498.4	124.6
PG&E	420.9	105.2
SDG&E	80.7	20.2
TOTAL	1,000.0	250.0

Given two auctions per year (adopted below ~~in our discussion of Market Elements~~), the 1,000 MW cap can not be subscribed ~~no more quickly~~faster than over a two-year period. It may take longer, depending upon the number of sellers and selected bids per auction. The rate of ~~subscriptions~~procurement is an

~~[86] For example, DRA recommends: "In order to cap the costs of the program, smaller initial auctions are recommended." (Pricing Comments at 10.)~~

[54] This is subject to the IOUs' discretion to reject contracts based on uncompetitive pricing, as discussed in Section 7.3.

important measure of the interest and success of the program, and will help us judge if and when to change the cap. The ~~124.6~~249.2 MW cap per year for SCE compares favorably to SCE's voluntary RSC program cap of 250 MW per year, and is reasonable.

We balance these concerns with the need to assure sellers ~~of a reasonable market~~ that is not so small as to ~~constrain~~limit the number of transactions. To do so, we require each IOU to offer no less than the allocated capacity for each auction.[55] SDG&E, for example, will offer ~~no less than~~ 20.2 MW in each auction~~, and may subscribe no more than 20.2 MW under RAM in any one auction~~.

We make one exception. The exception is that we require IOUs to bring ~~forward~~ unsubscribed amounts (or subscribed amounts that drop out of the program) to the next auction. That will increase the capacity offer (both maximum and minimum) in subsequent auctions by the amount of the unsubscribed (or dropped) capacity that is brought forward. This will promote seller assurance of ~~a reasonable~~the total market size, will assist with meeting California RPS goals, and is consistent with similar treatment in our two recently authorized solar PV programs.

~~7.2.6. **Must-Take**~~

~~The existing FIT is a must-take obligation selected on a first-come first-served basis at a known price (MPR) up to a program limit (e.g., initially 250 MW statewide, now 750 MW statewide). It includes a wait-list for additionally interested developers. ED's proposed expansion continued the must-take requirement for projects up to 10 MW, with an expanded program cap of 1,000~~

[55] As discussed earlier, an IOU may request an increase to this allocation in its initial implementation advice letter or in a future advice letter filing.

~~MW, but without a must-take duty for projects from 10 to 20 MW.[87] ED's revised proposed expansion recommended a revenue requirement cap, but does not allow an IOU to reject projects up to 10 MW until the revenue requirement cap is exhausted.[88]~~

~~PG&E recommends the must-take portion of RAM be limited to projects up to three MW.[89] Other proposals include: each IOU has discretion with respect to each project; the must-take duty is linked to maximum project size; or the FIT, by definition, is a must-take tariff offering and should be so here.~~

~~We include the must-take obligation with RAM, but only up to the level of the SPT or the auction's capacity cap. We agree with ED that a limited must-take requirement results in reasonable certainty for, and balance between, the market (regarding regulatory approach), ratepayers (regarding cost and the resource portfolio), and IOUs (regarding cost recovery). The Commission is authorized to establish IOU procurement practices, including resource-specific targets.[90] We do so here via the adopted RAM, including the must-take obligation up to 1,000 MW consistent with other adopted provisions (e.g., standardized contract, price up to SPT). We may adjust procurement parameters (e.g., project (transaction) cap, total program cap, SPT) in conjunction with the must-take duty, as necessary. We encourage IOUs and parties to monitor the program, including~~

~~[87] March 2009 Proposal at 5.~~

~~[88] August 2009 Proposal at 8.~~

~~[89] Pricing Reply Comments at 2.~~

~~[90] FERC "does not regulate the resource portfolios, including procurement choices, of the buyer (D.09-12-042, p. 8 (citation omitted).) The state has jurisdiction over retail sales service, which includes directing the planning and resource decisions of electric utilities under its jurisdiction. (16 U.S.C. § 824, subd. (b).)" (D.10-04-055 at 5.)~~

~~the effect of the must-take obligation, and, if warranted, propose reasonable modifications based on credible evidence.~~

~~We do not include a must-take obligation for prices above the SPT or beyond the auction's capacity limit. Prices above that level, or capacity beyond that limit, may still be agreed to between seller and buyer, but we require below a more thorough Commission review and consideration of such contracts (e.g., Tier 3 or application). Capacity related to contracts that are not must-take will not apply to the 1,000 MW program cap (as allocated to each IOU). This focuses the streamlined program and does not confuse it with others (parallel to our treatment below of the relationship of RAM to voluntary and other programs).~~

~~7.3. Eligibility~~

~~7.3.1. Location Restrictions~~

~~ED recommends that eligible projects must be located within the CAISO controlled grid. Parties argue eligibility relative to location should be narrower or more expansive.~~

~~We adopt a relatively more expansive approach. We do not limit project location, but require deliveries to be consistent with RPS eligibility standards, as determined by CEC.[91] This is the approach we use for RPS competitive solicitations. (See D.06-05-039 at 15.) We are not convinced to change that approach, or to adopt a different approach for RAM.~~

~~[91] The CEC certifies whether electricity may be used for compliance with the RPS program. (*See*: § 25741 of the Public Resources Code; also see "Commission Guidebook: Renewables Portfolio Standard Eligibility" (Third Edition, January 2008, CEC-300-2007-006-ED3-CMF); web link: http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-ED3-CMF.PDF.)~~
~~There is no reason to treat RAM differently.~~

~~We reject an IOU argument that project location should be restricted to the service territory of the IOU in which the project resides. IOUs contend that confusion may otherwise be created among the FITs offered by the three IOUs. We are not persuaded. We direct below that all tariffs and standard contracts be substantially similar, if not precisely the same. We are confident that reasonably talented project developers and sellers will be able to work with limited, if any, differences.~~

~~Moreover, an IOU service area limitation eliminates competition. RAM is not a viable price-setting option if the market is not competitive. Competition must be increased, not eliminated, for RAM to be effective, and the result to be just and reasonable.[92] We are persuaded by ED and parties that an area beyond each IOU's service area stimulates competition and provides reasonable flexibility for developers to locate in the most cost-effective locations.~~

~~We do not limit the area to the CAISO controlled grid. IEP convincingly argues that some of California's best renewable potential is outside the CAISO grid, such as in the Imperial Valley. There is no reason to limit the potential usefulness of the RAM by restricting it from some of the potentially best sites. We are comfortable relying on RAM and the market to best determine project location. This is the case for all electricity that CEC certifies is RPS eligible.~~

~~IOUs argue that such an expansive approach will increase costs by necessitating construction of additional transmission and distribution (T&D). We are not persuaded. First, below we adopt a requirement that projects be~~

~~[92] Elimination of competition would make the market a monopsony and preclude the use of RAM. The economically efficient, just, reasonable and not unduly discriminatory result in a monopsony RPS market would be the same as in a monopsony QF market (i.e., set the price at the full avoided cost of the buyer).~~

~~on-line within 18 months (subject to limited extensions). This provision will tend to focus projects on areas with available T&D. Second, when T&D is required, each project must pay reasonable T&D interconnection costs related to the project. This will naturally channel projects away from seeking interconnection that is cost prohibitive. Third, system (infrastructure) T&D costs generally apply to more than one RPS project. These costs are reasonably balanced with benefits in the decision whether or not to authorize T&D project construction. (See, for example, D.08-12-058, Sunrise Powerlink Transmission Project.) Reasonable costs are then allocated and charged to projects, if appropriate, or charged to users (e.g., via transmission charges). This allows the market to direct project selection decisions based on the economics. Fourth, SA and VSI convincingly argue that the issue of the cost of T&D upgrades to move power from IOU "A" to IOU "B" is actually overstated. There is little or no actual delivery in many cases. Rather, these transactions are more frequently solved by an accounting transaction, not the actual movement of power over long distances.[93]~~

~~In short, the limited time to completion criterion will tend to focus projects on areas with available T&D. Also, each project must pay the costs of project-specific new T&D, usage charges (e.g., transmission rates), and/or appropriate accounting charges. A rational bidder will include these costs in the bid as part of the RAM. Uneconomic projects will not be selected. Additional T&D construction associated with winning projects will be economic when projects are selected in least-cost order. We are comfortable relying on RAM and the market to best determine project location.~~

~~[93] Pricing Reply Comments at 6.~~

~~Reliance on the market, however, requires that all bids be on the same basis. We require below that IOU's propose necessary methods, if any, as part of the advice letters to implement RAM to ensure bidders submit bids on a comparable basis.~~

~~Finally, we reject a Sierra Club proposal to give community choice aggregators (CCAs) and energy service providers (ESPs) the right of first refusal for electricity from an RPS project in their service areas.[94] We seek to promote, not limit, competition. Tipping the scale in favor of CCAs or ESPs would unreasonably constrain the competition upon which this market is premised.~~

~~7.3.2. Retail Customer~~

~~ED recommends that the seller need not be a retail customer of the IOU. We agree.~~

~~The retail customer requirement was in the original legislation (AB 1969) and our initial implementation. It is not in the current FIT statute for projects up to 3 MW (§ 399.20 amended by SB 32 effective January 1, 2010). It is also not in our existing RPS program (annual bid solicitation), nor is it required in the QF program or as part of the LTPP. We adopt ED's recommendation for consistency with current law and other programs. We address related items below when we discuss third party ownership (i.e., that the facility need not be located on property owned or under the control of the retail customer).~~

~~[94] T&C Comments at 12.~~

7.3.3. **Utility Applicability**

ED proposes limiting RAM to the three largest IOUs. We agree.

SCE, TURN and RR argue that the RAM program should apply to all CPUC jurisdictional LSEs. We are not persuaded. We apply fundamental program basics to all LSEs (e.g., targets, reporting, penalties), including not only the largest IOUs but also SMJUs, CCAs and ESPs. Commission requirements regarding specific program elements vary by type of LSE, however, based on Commission regulatory authority, responsibilities and duties.[95] The degree to which such requirements may vary between LSEs, if at all, is under further consideration as a result of newly effective § 365.1(c)(1).[96]

For now, we limit RAM to the three largest IOUs. ED's proposal is made in the context of the three largest IOUs. We need further information before considering whether and how to apply RAM to other LSEs. We also make this decision in view of the following.

CCAs are expressly exempt from the provisions of § 365.1. There is no need to consider whether or not CCAs are required to implement RAM at this time.

SMJUs are not addressed in § 365.1. There is no obligation to require that SMJUs implement RAM at this time. Moreover, direct application to SMJUs is impractical. The largest allocation percentage for the existing FIT program is to

[95] See, for example, D.05-11-025, D.06-10-019, D.08-05-029.

[96] SB 695 (Kehoe), Stats. 2009, ch. 337. Section 365.1(c)(1) directs the Commission to "ensure that other providers are subject to the same requirements that are applicable to the state's three largest electrical corporations…" The provision was triggered upon issuance of D.10-03-022 on March 15, 2010. Pursuant to a Ruling dated March 25, 2010, parties have filed briefs and reply briefs, and a proposed decision is being prepared.

PacifiCorp, at 0.405% (less than one-half of one percent).[97] The total allocation to the four SMJUs is 0.599% (less than six-tenths of one percent).[98] Allocation to PacifiCorp (the largest of the four SMJUs) of its share of the 1,000 MW RAM total program adopted here would be about four MW (and to all four of the SMJUs would be about six MW). PacifiCorp would be allocated about one MW (and all four SMJUs would be allocated about 1.5 MW) in each of the four auctions adopted above. We are not persuaded that, as a practical matter, it makes sense to apply the RAM program (up to 20 MW per transaction) to each SMJU with allocated shares of four MW or less for the total program (and one MW or less per auction). We employed this same practical consideration in 2007 when we limited the required FIT offering by the SMJUs in the existing FIT to 1.0 MW rather than 1.5 MW. (See D.07-07-027 at 26.) We do so again here.

ESP obligations relative to RAM requirements, if any, need further development. We will hear from parties at a later time regarding whether or not to require ESPs to implement RAM, and if so under what terms and conditions. If appropriate, we may also at that time address additional considerations, if any, regarding CCA and SMJU implementation of RAM.

7.4. Uniform Terms or Uniform Contract

ED proposes that each IOU start with its existing 1.5 MW FIT tariff/standard contract and add or amend terms as needed to develop RAM, with the three IOUs having consistent T&C for the new terms. ED recommends that a uniform standard contract for all three IOUs be required over time, with IOUs filing a uniform standard offer no later than July 1, 2010 (about 15 months

---

[97] 1,013 kW divided by 250,000 kW is 0.405%. (See D.07-07-027 at 9.)

[98] 1,497 kW divided by 250,000 kW is 0.599%. (*Id.*)

~~after ED's proposal), to be in effect no later than January 1, 2011. Parties dispute the need and desirability of uniformity, with IOUs generally in opposition and some parties in support.~~

~~We adopt ED's recommendation. Each IOU must start with its existing FIT tariff/standard contract. It must add or amend terms as needed, and must employ consistent T&C for new terms, as it implements the orders herein. Each IOU must make every reasonable attempt to harmonize its RAM tariff, including the standard contract, with that of the other two IOUs.[99] Each IOU must undertake all reasonable efforts to work with the other two IOUs, staff and parties to develop uniform RAM tariffs.~~

~~Uniformity does not require that each contract be identical but, absent particularly compelling reasons otherwise, each should have the same form, same format, and substantially common (if not identical) language. For example, items should be addressed in the same order within the standard contracts. Language should be the same, or substantially similar, except for required differences. The hours and months included in a time of delivery (TOD) period, for example, might be different among IOUs, but the format and language regarding TOD should be the same.[100] Similarly, insurance provisions should be the same, even if the dollar amounts of coverage might differ.[101]~~

~~[99] Tariff, as used here, includes all applicable and appropriate related implementation documents, such as the accompanying standard contract and bid protocols.~~

~~[100] One approach is for the tariff and standard contract to be uniform among the three IOUs with appendices to address unique terms, such as TOD periods. (PG&E makes this proposal in its T&C Comments at 8-9.) In this case the form and format of each appendix should be the same, but with different values as necessary (e.g., hours or months for different TOD periods).~~

~~[101] SA and VSI T&C Reply Comments at 4.~~

We are not persuaded when IOUs contend that each has unique internal processes which necessitate differences. We see no reason for tariff language to differ between IOUs on common items (e.g., price, eligibility, deposits, performance standards, default, damages, applicable law). Unique items regarding different internal processes, if any, should nonetheless be in the same part of the tariff (e.g., same form and format), or accompanying document.

The advice letters ordered herein must be filed when due even if IOUs are unable to develop fully uniform tariffs, standard contracts and language by that deadline. ED may reject any one advice letter (or all three advice letters) if the tariffs fail to be sufficiently uniform. ED may require the IOU (or all three IOUs) to re-file the advice letter with a revised tariff. Once re-filed and accepted by ED, the IOUs may proceed with the first auction, whether or not the documents are fully uniform. Initiation of RAM should not wait for perfect uniformity.

Nonetheless, we agree with ED that uniform tariffs must eventually be developed. IOUs must work diligently with other IOUs, ED and parties to make substantial progress toward, if not reach, the uniformity goal by the time advice letters are filed to first implement the RAM (21 days after the date this order is mailed). If unable to reach that goal within 21 days, IOUs must reach the goal no later than nine months from the date of issuance of this order.

7.5. Negotiations

ED proposes that RAM standard contract T&Cs not be negotiable. Similarly, bid prices are not negotiable.[102] We agree.

We streamline procurement with RAM by adopting a standard contract with uniform T&Cs, program capacity cap, market mechanism to determine

[102] August 2009 Proposal at 9.

price, SPT (for simplified standard contract review of eligible contacts), and other standardized provisions. The result is to provide IOUs and the state with a simplified additional opportunity to meet RPS, GHG and other goals. This makes it relatively easier and less costly for all stakeholders.

We decline to allow negotiations within RAM since this will add time, cost and complexity. Buyers and seller have other opportunities that permit negotiations if and when necessary (e.g., bilateral negotiations, the annual RPS solicitation, IOU voluntary procurement programs). In this context, it is reasonable to make the RAM tariff take-it-or-leave-it (non-negotiable) up to the level of the SPT. Price is determined by the market (auction), with the seller submitting its bid, and the buyer making its selection on the basis of price. This reasonably promotes the goal of streamlining and simplification without the Commission influencing the pricing or foreclosing any other alternative.

7.6. **Project Viability**

ED proposes that projects meet four minimum project viability criteria before being eligible to submit a bid. These include, for example, site control and equipment standards.

Parties present a range of views. Those in support argue the criteria will streamline review and facilitate program success. Those in opposition assert the criteria unreasonably increase project costs and risks.

We adopt ED's proposed minimum project viability criteria, and add one, as explained below. The five adopted criteria provide an initial screen of likely more viable from possibly less viable projects. This will substantially simplify bid review and selection.

7.6.1. Discussion

Some parties argue for little (or no) upfront screening with lenient (or unlimited) extensions on the amount of time to begin commercial operation. In support, advocates of this approach say this will reduce cost and increase supply. We are not persuaded.

We accept their assertion that project viability criteria will increase upfront costs for project participation, and increase investor risk of not recovering those costs if the project is not selected. We have no credible estimates of the amount of increase in upfront costs or investor risk, however, and no way to concretely assess the incremental effect. On the other hand, RAM is an option for IOUs and projects. If investors are unwilling or unable to shoulder those costs and risks within the context of the RAM, they may use other procurement options.[103] Further, the risk of failing to recover upfront costs provides a modest incentive for submission of a realistic, competitive price. This should help offset other incentives for the bidder to submit a bid price as high above cost as possible (e.g., if the bidder is otherwise willing to take a gamble that only a few projects will bid).

Reasonable project viability criteria also complement other adopted program elements. For example, we adopt a provision below that projects have 18 months to come on-line, with limited ability to obtain extensions. Minimum

[103] We are persuaded by Recurrent that: "…reasonable project viability requirements are essential to creating sustainable long-term markets for renewable generation, and that responsible developers and IPPs [independent power producers] welcome such requirements. … To suggest that reasonable viability requirements will preclude small developers from participating is disingenuous: what such requirements preclude is bidding unrealistic projects, without regard to a developer's size." (Pricing Reply Comments at 10.)

~~project criteria at the time of bid submission support a limitation on time to commercial operation.~~

~~Project viability criteria also assist with project queue management. Lenient screening and extensions would present an unacceptable risk of clogging the limited project queue (e.g., 250 MW per auction). This would be unfair to other projects that could develop and deliver power but which are otherwise blocked by projects which would fail reasonable upfront screening criteria or which have obtained excessively lenient multiple extensions. A clogged queue is unfair to Californians who expect the state to reach the RPS target of 20% by 2010, and goal of 33% by 2020. The right balance is a timeframe for commercial operation with limited possible extensions complemented with limited project viability criteria before being eligible to submit a bid. This will facilitate screening, evaluation and selection. Reasonable upfront project viability criteria should also reduce the number of requests for extensions.~~

~~We also adopt project viability criteria in recognition of project investment costs. That is, each project will be costly (e.g., hundreds of thousands or millions of dollars per project). At this level of per project investment, we elect to place a modest amount of responsibility upfront and be relatively strict on project milestones (i.e., 18 months with limited extensions). This will advance RPS program success. It is a balance that is reasonable and fair to the selected projects, those waiting to get into the queue, and stakeholders in general.~~

~~We now address the adopted criteria.~~

7.6.2. **Adopted Criteria**

7.6.2.1. **Site Control**

ED recommends the bidder must show 100% site control through (a) direct ownership, (b) lease, or (c) an option to lease or purchase that may be exercised upon award of the contract. We agree.

We want RAM to be available for projects that are not unduly speculative. To do this, it is reasonable to require site control. This makes the project a more likely real choice for the IOU and ratepayers, not a speculative concept dependent upon a string of other variables. Projects that are more speculative may use other procurement vehicles.

7.6.2.2. **Development Experience**

ED recommends that the bidder must show the company and/or development team has (a) completed at least one project of similar technology and capacity or (b) begun construction of at least one other similar project. We agree.

Some parties object, saying this criterion is too subjective and exclusionary. Rather, they assert that the pay-for-performance nature of the program ensures that only viable projects will participate.[104]

We agree that pay-for-performance is a powerful tool that facilitates viable project self-selection. It is not enough for RAM, however. We seek a streamlined process that promotes ease of bid review and selection of projects which can become operational or be removed (to open the queue for another project).

---

[104] Pay-for-performance refers to the payment mechanism wherein projects are paid upon delivery of the product (i.e., electricity), with no payment when there is a failure to perform.

~~Development experience complements pay-for-performance in promoting that objective.~~

~~7.6.2.3. Equipment Standards~~

~~ED recommends that solar PV equipment must be on lists approved by CEC and Underwriter's Laboratories (UL), and other technologies must meet similar standards if such standards exist. We agree.~~

~~Some parties object, saying this criterion is too restrictive. To the contrary, this criterion will promote streamlining of bid review and selection, and facilitate reopening of the queue for stalled projects. It does not foreclose projects with other equipment from selecting another contracting option.~~

~~7.6.2.4. Commercialized Technology~~

~~ED proposes RAM be for commercialized technologies. ED recommends commercialized technology be defined as one currently in use at a minimum of two operating facilities of similar capacity worldwide.~~

~~We agree with a commercialized technology screen. Research, demonstration and development (RD&D) are vital, and we encourage RD&D, but RD&D should be funded in ways other than RAM.[105]~~

~~The RPS program itself is largely intended for commercial technologies. California seeks 20% by 2010 with reasonably proven technologies that will~~

~~[105] RD&D might, for example, be funded by private companies, private foundations, industry-funded entities (e.g., Electric Power Research Institute), universities, venture capital funds, or government (e.g., CEC's Public Interest Energy Research (PIER) Program). We generally agree with TURN that: "It [RAM] should not be revisioned as an RD&D program. There are existing state subsidy programs for renewable technology development (PIER) and for on-site installations of wind, fuel cells and CHP generation to offset on-site load (SGIP). This is not the role of the RAM, which is intended to provide a more streamlined and certain procurement route for small renewable projects." (Pricing Reply Comments at 6.)~~

provide safe and reliable electricity at just and reasonable rates. Experimental technologies may seek a place in the RPS resource mix in other ways and apply via other approaches (e.g., bilateral negotiations).

7.6.2.5. Interconnection Application

Finally, Recurrent recommends that bidders demonstrate they have filed their interconnection application by the time they bid into the RAM.[106] We agree.

An interconnection application requires high-level initial engineering. The process can easily take six months or more for projects up to 20 MW. Given the 18-month deadline for commercial operation, projects will likely have begun the interconnection application process by the time of bid submission. It is also a reasonable screening criterion for bids. IOUs should require bidders to show with bid submission that the interconnection application has been filed. We expect a RAM auction to be held at least every six months, thereby providing reasonable ongoing opportunities to participate if the interconnection application requirement results in a project missing a particular RAM deadline.

7.6.3. Administration

The project viability criteria adopted above use some specific terms (e.g., "similar" project) and equipment standards. We decline to adopt specific definitions or exact equipment lists. Rather, we let IOUs do so with input from projects, parties and staff. This is not a level of detail we need to address here. We expect IOU definitions and lists to be reasonable, and will judge the result as part of overall RPS program administration, as necessary.

We expect IOUs to administer the project viability screen by designing RAM (including bid protocol) to require that each bidder show compliance with

[106] Pricing Reply Comments at 10.

~~the adopted project viability criteria. IOUs may reject bids from projects which fail to meet these minimum criteria.~~

~~Finally, we adopt a provision below to periodically collect information on RAM. We may modify project viability criteria if data show the screening process significantly reduces the number of interested and eligible projects, and reduces the competition and effectiveness of RAM. For initial implementation, however, a modest amount of bidder self-screening will simplify bid review and selection while complementing other program elements and providing an incentive to submit realistic, competitive bids.~~

~~8. Products and Price Design~~

~~8.1. Products~~

~~One of the challenging design issues is identification of the appropriate RAM products.~~

~~8.1.1. Background and Positions~~

~~The existing FIT product is energy (kWh) purchased by TOD. Selection is made in first-come first-served order. The product is subject to a program maximum measured in total statewide capacity (MW). The standard contract contains performance requirements (e.g., good utility practice, prudent electrical practice), minimum general liability insurance amounts, and damage provisions.~~

~~ED recommends RAM be used for predetermined amounts of renewable products based on individual renewable needs of each IOU. ED offers three examples of products: baseload, peaking as-available and non-peaking as-available. ED proposes that annual RPS procurement plans specify how much of each product the IOU will procure, with selection based on price and limited~~

by a revenue requirement cap for each product category.[107] In addition to existing performance obligations, ED proposes that the seller must deliver a minimum of 140% of its expected annual net energy production based on two years of rolling production.[108]

Parties offer a range of views. SCE says that each auction should be open to all technologies and not be limited by specific types of resource categories, such as baseload, peaking as-available and non-peaking as-available. Others, such as FCE, GreenVolts, Inc. (GreenVolts), Sierra Club California and GPI, argue for technology differentiation, asserting that this helps preserve production differentiation and encourages resource diversity.[109]

8.1.2. **Discussion**

For the reasons explained below, we adopt firm, non-firm peaking, and non-firm non-peaking as the three products, but do not specify the amounts of each product to be purchased by each IOU. We authorize each IOU to specify the amounts of each product, subject to Commission reasonableness review of program administration.

In reaching these decisions, we first employ the relatively simple approach in FIT (existing). We there authorize purchase of electricity without additional product differentiation, but use TOD-differentiated rates as an incentive for the seller to offer the product when it is most desired by the IOU.

---

[107] August 2009 Proposal at 8.

[108] March 2009 Proposal at 11.

[109] GPI recommends cost-of-generation based fixed-price tariffs. (Pricing Reply Comments at 5.) Generation costs vary by technology. A cost-of-generation based fixed-price tariff would therefore require different tariffs by technology.

~~We recognize, however, that some product differentiation is necessary when using a price auction (rather than first-come first-served) to select winning sellers. Ranking only by price without any other differentiation will skew results to the lowest cost projects without reasonable product diversity. For example, one resource type (e.g., non-firm wind) is likely to be the least expensive and, if all bids are ranked only by price, this one resource type might secure all 1,000 MW of RAM. It would, however, almost certainly be unwise to purchase only one type of product (e.g., non-firm versus firm) from one type of technology (e.g., wind). Stakeholders are better served by some product differentiation.[110]~~

~~We decline to differentiate the products in RAM by technology. There are at least nine candidate technologies.[111] We have inadequate data to determine how much of each technology might be reasonable for each IOU.[112] Also, SDG&E's allocation of 81 MW (20 MW per auction), if divided equally by seven technologies, would be about 12 MW per technology (or 3 MW per technology~~

~~[110] We encourage IOUs to diversify resource portfolios to reasonably manage risk. For example, resource portfolios should be composed of a reasonable mix across all relevant variables. Relevant variables might include length of contract (such as short term, medium term, long term), pricing terms (such as flexibility in relationship to market, with fixed prices over a 20-year contract for some purchases and prices subject to periodic adjustment over a 20-year contract in other purchases), ownership type (e.g., purchases from IPPs versus utility-owned generation within our adopted hybrid market approach), and others that result in reasonable risk management and diversification in order to have a robust resource portfolio.~~

~~[111] ED identifies seven technologies: geothermal, biomass, biogas, fuel cells using renewable fuels, solar PV, solar thermal, wind. (August 2009 Proposal at 8.) There is also in-conduit hydro, ocean wave, and there are likely others.~~

~~[112] SA recommends 75% of initial program capacity be allocated to the peaking as-available product on the basis that solar PV has the greatest potential to reach wide-scale penetration at the distribution level. (Pricing Comments at 13-14.) We lack adequate data on the other six or more technologies to make a reasonably informed decision.~~

~~per auction). This is substantially less than one 20 MW project (transaction) eligible for the RAM. This limitation conflicts with the designed availability of the RAM option to projects (transactions) up to 20 MW.~~

~~Instead, we look at the electricity products that utilities largely seek from merchant generators in other procurements (e.g., QF market, RPS solicitations). Those are basically firm and non-firm (as-available).[113] ED recommends differentiating non-firm into peaking and non-peaking given generation profile differences. We agree. It is reasonable to seek three products in the RAM, providing reasonable diversification without excessive complexity.~~

~~We do not have enough information to specifically define the generation profiles and other characteristics that would correspond to each of these products. The IOUs shall include in their initial advice letter filing pursuant to this order a detailed description of the generation profiles and characteristics that~~

~~[113] For example, in the RPS annual bid solicitation, PG&E seeks four products: as-available, peaking, baseload and dispatchable. (See PG&E 2010 Solicitation Protocol, June 2, 2010 at 7-8.) PG&E defines these as:~~

1. ~~as-available is intermittent energy and capacity deliveries that are subject to a fuel source not controlled by the generator~~
2. ~~baseload is energy and capacity delivered on a 24 hour and seven day per week schedule (24x7) with an annual capacity factor of at least 80%~~
3. ~~peaking is energy and capacity delivered on a five days per week and eight hours per day schedule (5x8) during June through September with a capacity factor of at least 95%~~
4. ~~dispatchable is energy and capacity available for delivery on a day-ahead or intra-day schedule with a monthly availability factor or at least 95% in certain months~~

~~"As-available" (or non-firm) said more generally is energy or capacity deliveries that are intermittent for any reason (e.g., wherein the seller does not commit to specific deliveries due to uncontrollable fuel source or any other reason). In contrast to~~

correspond to each of the three adopted product categories. The advice letter filing shall also detail how the eligibility requirements will provide reasonable assurance that a bid for one product will, if selected, deliver energy in a manner that corresponds to the generation profile associated with that product (e.g., non-firm peaking).[114] This concern is most relevant to the two non-firm products given that we adopt performance requirements below for firm products. If a non-firm project is unable to provide reasonable assurance, based on resource availability or other factors, that it will deliver energy consistent with an on-peak product then, provided it meets other eligibility criteria, it may participate but only as a non-peak product.

With regard to performance requirements for non-firm electricity (i.e., constraining non-firm to a TOD period subject to penalty for noncompliance), we believe such requirements are inconsistent with the concept of an as-available (non-firm) product. Non-firm is delivered when it is generated. Non-firm cannot be scheduled and realistically tied to performance requirements by TOD. Nonetheless, as described above, non-firm resources will, in effect, be pre-certified as either peaking or non-peaking based on the criteria identified by the IOUs in their advice letters (and to the extent authorized by us upon review of the advice letters). On the other hand, firm electricity requires a commitment, and, in the discussion below on Performance Obligations, we adopt a performance requirement based on ED's recommendation.

---

as-available (non-firm), the other three products involve various delivery requirements or degrees of "firmness."

[114] For example, if a wind project seeks to bid in as a non-firm peaking product, one potential way of providing some level of assurance that the project will actually produce energy on-peak is to require the project to provide some minimum level of

ED also recommends that RAM use predetermined amounts of product based on individual IOU needs. While we adopt three products (firm, non-firm peaking, and non-firm non-peaking) for the initial roll-out of RAM, we have inadequate data to direct the quantity of each product that each IOU should seek. We require each IOU to establish the amounts of each product for each auction, subject to Commission reasonableness review of IOU administration of the program. The first advice letter filed pursuant to this order (within 21 days to establish RAM) must state the amounts of each product for each of the initial four auctions. The IOU must make its selections consistent with the stated quantities and may not alter the quantities after the auction quantities are first announced. This will provide reasonable stability and certainty to the auctions, and avoid the appearance or actuality of "bait and switch" by the IOU.

8.2. Selection

Rates are fixed under the existing FIT with projects selected on the basis of first-come first-served. With RAM, ED proposes that project viability criteria first be applied to screen out ineligible projects. ED recommends project selection among remaining eligible projects by price, using an auction approach, with no ability by parties to negotiate terms, conditions or prices. Rather, ED advocates that projects submit a price bid and IOUs make selections on the basis of price, first selecting the least expensive projects in each product category.

Many parties support selection based on price in order to secure the least-costly products with the maximum benefits of price competition. SCE supports the use of an auction to determine the price for each project, but recommends only one product with the selection not made on the basis of price,

---

meteorological data demonstrating that the times when the wind resource is available coincide with on-peak periods.

~~but made on the basis of value. According to SCE, this method permits the IOU to select the best combination of resource types and deliveries. Parties mention other alternatives, such as selection based on project viability or lottery.~~

~~First-come first-served works best when prices are fixed in the tariff and known to all parties in advance. It does not work well in the context of an auction with a goal of the buyer securing the least-costly products. Similarly, project viability and lottery each fail to adequately consider cost.~~

~~We agree with ED that selection should be limited to the price variable. We seek relative simplicity and transparency in the RAM program. Selection based on price is consistent with these objectives, particularly if price is expressed in cents/kWh to simplify comparisons. We decline to use value as a selection criterion since it potentially introduces an unacceptable amount of subjectivity into the RAM.[115]~~

~~We expect price to be expressed in cents/kWh based on a realistic production profile of the project. IOUs should include, as part of the RAM bid protocol, a requirement that the bid be in cents/kWh and the bidder include the project's expected production profile. We expect IOUs to use their own judgment about the production profile to eliminate unrealistic bids.[116]~~

~~It is also necessary to require that the bid price be stated on the same basis so the IOU can make a reasonable selection based on least cost first. For example, some projects may exclude costs that are included by other projects (e.g., transmission, firming/shaping). IOUs should normalize bids, if necessary,~~

~~[115] Selections which include subjective elements (e.g., least cost best fit - LCBF) are left to other programs (e.g., IOU voluntary programs, bilateral negotiations).~~

~~[116] An IOU should, for example, reject a firm product bid from a resource that submits a generation profile inconsistent with a firm product.~~

~~to ensure that they may be compared on an equal basis. As part of the advice letters to implement RAM (within 21 days of the date of this order), IOUs should include and explain any normalization procedures the IOU intends to use as part of its bid selection process.~~

~~We allow projects to bid into multiple auctions to promote competition. This may result in a project being selected by more than one buyer. We expect each such bidder (i.e., that has bid into more than one auction and been selected by more than one buyer) to make a decision and inform all interested buyers within a reasonable amount of time after being notified of its selection by the last of such buyers. That should be able to be done within five calendar days. IOUs should include this procedure and timeframe within their bid protocol (to be filed as part of the tariff, discussed more fully below under Implementation). To ensure that RAM can proceed smoothly, we require that each seller execute the standard contract within 15 calendar days of the date the buyer notifies winning bidders.[117] IOUs should propose uniform schedules for simultaneously conducting the RAM, including bid evaluation and notification of bidders, to simplify the process for bidders and facilitate efficient administration of the auctions.~~

~~We agree with the concern expressed by some that selection only by price may tend to skew selection to only the least expensive technology able to serve each of the three products (e.g., geothermal for baseload, solar for non-firm peaking, wind for non-firm non-peaking). This may leave out seven or more other technologies. Parties may recommend changes, based on annual reports~~

~~[117] A seller unable to execute the standard agreement within 15 days after notification is ineligible to continue with the RAM. The buyer and seller may proceed with other options (e.g., next RAM auction, bilateral negotiations, annual RPS competitive solicitation, QF market, CAISO day-ahead market).~~

and evaluations discussed below, if initial results show that the three product choices (firm, non-firm peaking, non-firm non-peaking) and selection criterion (price) unreasonably skew results. For the initial roll-out of this program, however, the adopted elements (e.g., three products selected on the basis of price) with protections against adverse outcomes (e.g., MW cap and SPT for simplified contract review) provide a reasonable basis to proceed, permit learning from the experience, and allow parties to recommend refinements, if necessary, to further improve the program and its results over time.

8.3. Simplified Preapproval Threshold

PG&E and others propose a Commission-established price cap for each product. According to this view, a price cap protects customers from exorbitant prices when competition is otherwise not robust.[118] We agree with the ratepayer protection objective, and accomplish this by use of an SPT. We summarize the proposals, discuss the options and address the SPT.

8.3.1. Proposals

Parties present a variety of price cap proposals. For example, TURN recommends a workshop on the topic, and states that one alternative is a baseload price cap at no more than 75% of the average price of products bid into the peaking as-available auction. GreenVolts recommends the winning price could be limited to no more than 125% of the highest winning bid in the general auction.[119] PG&E recommends a price cap in the form of MPR plus a dollar per megawatt-hour (MWh) premium, with the premium for as-available peaking higher than that for as-available non-peaking so parties can see the renewable

[118] PG&E Pricing Comments at 15-16.

[119] Pricing Comments at 6.

premium associated with each product. Reid recommends that no bid be considered at a price greater than 120% of MPR, rounded up to the nearest $5/MWh.[120]

8.3.2. **Discussion**

We decline to adopt a price cap or similar mechanism based on auction results. The auction itself may or may not include a sufficient number of projects to reflect a competitive, optimal outcome. The purpose of this mechanism is to streamline administration and help prevent adverse outcomes if the underlying market is not sufficiently competitive. We cannot base the mechanism on an outcome that may not itself be reasonable. Doing so would subject the results to unacceptable circularity, and fail to achieve the ratepayer protection goal.

PG&E and Reid propose a price cap of MPR plus a premium. This general approach has merit, particularly when the total does not exceed a reasonable alternative cost, or otherwise result in an excessive price.[121] We decline to adopt a price cap but instead adopt an SPT. The SPT does not consider whether the wholesale rate is just and reasonable. Rather, the SPT focuses on our responsibility to determine whether an IOU wholesale purchase is prudent in relationship to alternatives and preapproved for cost recovery.

The SPT mechanism provides that an IOU batch and submit all standardized RAM contracts in one Tier 1 advice letter for contracts with a rate less than a specified level of SPT. This will permit simplified review and approval of contracts which we have essentially predetermined to be reasonable at a price less than the SPT level. It provides assurance of cost recovery for the

---

[120] Pricing Comments at 2.

[121] The highest reasonable cost would likely be the IOU's cost to provide the same product by utility owned generation.

~~IOU.[122] It allows the IOU to bring contracts at levels at or above the SPT to the Commission for review under other procedures (e.g., Tier 3 or application).[123]~~

~~The SPT does not set the market price, but differentiates the type and level of review to be undertaken by the Commission in our determination of whether the IOU purchase was prudent and reasonable for preapproval of permissible retail rate recovery. Buyers may bid whatever price they seek. We require the utility to take contracts up to the adopted limits (i.e., MW capacity or at prices below the SPT level) as an element of our administration of resource procurement and portfolios. An IOU is not obligated but may also select each and every other contract that it finds reasonable (e.g., above the MW capacity or at prices at or above the SPT level), and file that contract for Commission consideration by other than a Tier 1 advice letter.~~

~~We adopt an SPT recognizing that a 1,000 MW capacity cap provides important protection, but does not itself protect against excessive cost for any one individual contract. The adopted mechanism provides the right balance of streamlined administration, preapproved cost recovery for the IOU, reasonable resource portfolio administration, and focused Commission consideration of the prudence of entering into certain contracts.~~

~~We adopt the SPT level based on PG&E's recommendation of MPR plus a premium, with the premium set at a level of 50% of the MPR. This level is reasonable. It is less, for example, than the price cap adopted for either of two~~

~~[122] § 454,5(d)(2). Cost recovery is predetermined to be reasonable and is assured subject to Commission review of IOU contract administration.~~

~~[123] If approved under those procedures, the IOU also has assurance of cost recovery, subject to Commission review of contract administration.~~

~~recently approved programs (e.g., $0.26/kWh for SCE and $0.246/kWh for PG&E).[124] This will permit the initial roll-out of the RAM.~~

~~The adopted SPT level (the most recently adopted MPR plus 50%) for a 20-year product beginning in 2011 in cents/kWh, for example, is:[125]~~

~~TABLE 3~~
~~CALCULATION OF ANNUAL SPT~~
~~(cents/kWh; 20 year contract beginning 2011)~~

~~ITEM~~	~~RATE~~
~~MPR~~	~~10.10~~
~~RAM SPT (MPR plus 50%)~~	~~15.15~~

~~We allocate the SPT level (MPR plus 50%) to each IOU's TOD periods to reflect reasonable cost avoidance and the differential value between energy delivered during on-peak periods relative to energy delivered during mid- and off-peak periods (using the TOD factors in the existing FIT). This is consistent with PG&E's recommendation and is parallel to our time-differentiation of the~~

~~[124] See D.09-06-049 at 30, 28. Also see D.10-04-052, Appendix A at 2. It is also less than the proposed cost cap of $0.235/kWh for SDG&E's solar PV program. (See July 13, 2010 Proposed Decision of ALJ Ebke in Application 08-07-017.) The maximum SPT adopted here is $0.21636/kWh (which is 150% of the MPR ($0.14424/kWh) for a 25-year contract beginning in 2021). (For MPR see Resolution E-4298 issued December 18, 2009.) We said regarding the PG&E PV Program: "A price cost cap for PPAs will ensure that the costs of the PV Program are not excessive and should be adopted." (Conclusion of Law 6 in D.10-04-052 at 77.) We said regarding the SCE PV Program: "At the same time, capping the price paid to IPP projects at 100% of SCE's LCOE [levelized cost of electricity] provides reasonable protection to ratepayers against the total cost of the program." (D.09-06-049 at 38.)~~

~~[125] See Resolution E-4298, issued December 18, 2009.~~

~~MPR generally throughout the RPS program, including FIT (existing). The SPT will be aligned to the duration of the contract.[126]~~

~~The RAM SPT by TOD by IOU[127] is:~~

~~TABLE 4~~
~~REASONABLENESS THRESHOLD BY TOD~~
~~(cents/kWh; 20 year contract beginning 2011)~~

~~PERIOD~~	~~SCE~~	~~PG&E~~	~~SDG&E~~
~~SUMMER~~			
~~On~~	~~47.41~~	~~33.40~~	~~24.86~~
~~Mid~~	~~20.45~~	~~17.00~~	~~15.75~~
~~Off~~	~~11.36~~	~~10.45~~	~~13.38~~
~~WINTER~~			
~~On~~	~~15.15~~	~~16.02~~	~~18.05~~
~~Mid~~	~~12.57~~	~~14.16~~	~~16.34~~
~~Off~~	~~9.24~~	~~11.57~~	~~12.01~~
~~OTHER~~			
~~On~~	~~NA~~	~~17.36~~	~~NA~~
~~Mid~~	~~NA~~	~~12.82~~	~~NA~~
~~Off~~	~~NA~~	~~9.73~~	~~NA~~

~~[126] That is, for example, 10-year SPT for a 10-year contract, 15-year SPT for a 15-year contract, 20-year SPT for a 20-year contract.~~

~~[127] See each existing FIT for TOD definitions. The periods differ by IOU. (SCE's FIT (existing) calls these TOU periods, but they are treated here the same as TOD periods.) In summary:~~

- ~~PG&E summer is June 1-September 30; winter is October 1-February 28, other is March 1-May 31. The summer on-peak is Monday-Friday (except certain holidays) from 1 p.m. to 8 p.m.~~
- ~~SCE summer is June 1-September 30; winter is October 1-May 31. The summer on-peak is Monday-Friday (except certain holidays) from noon to 6 p.m.~~
- ~~SDG&E summer is July 1-October 31; winter is November 1-June 30. The summer on-peak is Monday-Friday (except certain holidays) from 11 a.m. to 7 p.m.~~

~~PG&E recommends that the premium for as-available peaking be higher than that for as-available non-peaking. Allocation of the 50% premium to TOD accomplishes this result (since the allocation factors to on-peak periods exceed allocation factors to non-peak periods).~~

~~We decline to use Reid's recommendation to adjust the SPT (MPR plus 50%) by rounding the result up to the nearest $5/MWh. This adds an additional step and level of complexity that is unnecessary.~~

~~The generation profile of each project will be different. The SPT level by TOD must be applied to a project's generation profile to determine a project-specific SPT. The project specific SPT may then be compared to the bid price to ensure the bid price is less than the SPT. Projects which pass this screen are then subject to being selected in the order of least costly first. Projects selected at a price less than the SPT level are eligible for a Tier 1 advice letter submission to the Commission, as explained more below (see Chapter below on Regulation and Commission Oversight). Projects selected by the IOU at and above the SPT level may be submitted for consideration by Tier 3 or an application.[128]~~

~~8.4. Summary~~

~~The adopted products are firm, non-firm peaking, and non-firm non-peaking. Bids must state the product for which the bid is submitted. The IOU bidding protocol should require bids to be stated in cents/kWh, and include the project's expected production profile. The price ranking of bids is from least~~

~~[128] There is no must-take obligation for projects priced above the SPT. The IOU may elect to pursue the project, however, and submit the contract for normal Commission review.~~

~~costly to most costly, and is compared to the SPT (developed per project using the project's generation profile). For purposes of each auction, IOUs must use the most current Commission-adopted MPR, and Commission-authorized TOD factors, unless and until superseded by further Commission direction. Projects within each product type are selected in the order of least costly first up to the MW limit or until no projects remain at a price below the applicable SPT level. The selected contracts are must-take and are eligible for submission to the Commission by Tier 1 advice letter. The signing of other contracts (for MWs in excess of the auction limit or a rate at or above the SPT) is subject to the discretion of the IOU, and should be submitted to the Commission under other procedures (e.g., Tier 3 or application). The capacity of these other contracts will not count toward the overall 1,000 MW capacity cap (nor the amounts allocated to each IOU).~~

~~8.5. Rate Design~~

~~8.5.1. Background~~

~~A significant Commission responsibility when an IOU sells electricity to ratepayers is to set the rate level (e.g., $0.12/kWh) and rate design (e.g., tier or TOU structure). Rate level and design can affect many important aspects of the sale. For example, the level and design affect how much and when electricity is purchased. They also affect the stability of the IOU's revenues and profits.[129] We employ many rate design tools when the IOU is the seller, and each tool can provide incentives to either the buyer and/or seller. These tools include customer charges (dollars per customer per month), demand charges (dollars per~~

[129] ~~Profit variability can be a function of how closely rates align with the IOU's costs and changes in those costs driven by changes in sales. Said generically, it depends upon~~

~~kW per month), and energy charges (cents per kWh). Balancing accounts or memorandum accounts are often used to promote rate stability for the ratepayer and cost recovery for the IOU. Adders are used for special programs or purposes (e.g., public purpose program surcharge).~~

~~The same issues arise for the rate level and rate design employed for IOU purchases under a FIT. In particular, when the IOU is the buyer, the FIT rate level and design can affect how much electricity the seller elects to sell and when. They can also affect stability of the selling firm's revenues and profits, which in turn can affect the project's cost of capital and ability to obtain financing. A range of rate designs are available when the IOU purchases RPS electricity, and can be used by the IOU to provide incentives to the seller.~~

~~The current FIT (for projects up to 1.5 MW) pays for electricity using an all-in rate expressed in cent/kWh (i.e., an energy rate) differentiated by TOD.[130] Current model contracts in the annual RPS competitive bid solicitations use energy prices paid by TOD, with some use of capacity prices paid by monthly factors subject to availability adjustments.[131]~~

~~whether the marginal revenue (the price for the last unit sold) is equal to the marginal cost (the cost for the last unit sold).~~

~~[130] "All-in" refers to the inclusion of all fixed costs (e.g., capital) and all variable costs (e.g., fuel, labor, supplies, materials).~~

~~[131] See, for example, PG&E 2009 Solicitation Protocol, Attachment H (Form of Power Purchase Agreement), Section 4.8 and Appendix XIV (Additional Dispatchable Product Provisions and Capacity Price terms), with payment by monthly time of availability and minimum availability factors. Also see SDG&E 2009 RPS Procurement Plan, Appendix B5, Section 4.1 with the capacity price adjusted by a monthly shaping factor and availability adjustment factor.~~

ED proposes that the RAM use energy rates, the same as the existing FIT program (all-in paid by TOD). The August 2009 ALJ Ruling asked parties to address a range of price structure (rate design) issues.[132]

8.5.2. All-In Energy Rate Paid by TOD

Parties are unanimous in recommending the use of existing pricing approaches, wherein prices provide reasonable incentives for performance. We agree.

Parties are nearly unanimous in recommending the use of an all-in energy rate paid by TOD.[133] We agree with parties that an all-in energy rate paid by TOD provides a powerful performance incentive and moderates ratepayer risk. This is the case since payment is made only for delivered electricity. We adopt the continued use of all-in energy rates paid by TOD for the RAM.

Limited comments support use of a capacity rate. For example, TURN recommends an all-in time-differentiated and levelized energy price. TURN also says: "Fixed capacity payments may be appropriate for dispatchable resources

---

[132] At the time of the Ruling, no decision had been made on the type of expanded FIT that might be adopted. Options included: (a) an expansion of the existing FIT from 1.5 MW to 20 MW at a fixed price (e.g., MPR), (b) the ED proposed RAM or (c) any other FIT recommended by a party. Parties were asked to identify or address: the stakeholders with respect to the expanded FIT, stakeholder interests, candidate price components for the expanded FIT, best combination of price components to meet stakeholder interests, and whether or not the Commission should state a preference or a requirement for certain price components. Parties were asked to comment on five possible rate designs and state anything else necessary for a complete consideration of the issues. Finally, parties were asked to state a specific recommended price structure (rate design) for the expanded FIT.

[133] Parties responded to the ALJ Ruling by voting on price structure with the price components identified in the Ruling. (Pricing Joint Comments at 4.) The majority support the use of energy rates: 20 out of 24 party votes for pricing structure elements are for the energy rate (cents/kWh), two for fixed payment (dollars/customer) and two for adjustments (e.g., tied to an index). (*Id.*, Attachment A at 3.)

that provide resource adequacy value recognized by the CAISO."[134] Other parties agree that a capacity payment may be reasonable when capacity is provided.[135]

We decline to direct the separate use of capacity rates, particularly considering the nearly universal opposition. Also, capacity rates involve an additional level of complexity that does not appear necessary for these relatively small resources. For example, SCE does not use capacity prices in its RSC program, even though SCE originally designed this program for bioenergy resources which have the potential to provide dependable capacity.

Thus, we direct the use of all-in energy rates paid by TOD for the expanded FIT. This approach is reasonably simple, pays for performance, and provides an incentive to provide electricity by TOD when it is most needed.

8.5.3. Escalation Factors

SCE says sellers "may choose to include escalation factors in their bids."[136] No party argues otherwise.

We permit bids for the RAM to include escalation factors.[137] Bid prices will be TOD-adjusted and levelized, as necessary, just like other bids in order to compare the bid price to others in the auction. We are confident that each IOU can perform a reasonable net present value calculation and risk assessment to

---

[134] Pricing Comments at 6.

[135] GPI Pricing Comments at 8. Recurrent Pricing Reply Comments at 11.

[136] Pricing Comments at 14. An escalation factor, for example, might be a specific price index, fixed percentage, or formula that is applied to the first-year bid price to yield the second-year price, and similarly applied every year thereafter.

[137] Price escalation is also allowed in the annual competitive bid solicitation. SCE and SDG&E, for example, permit bidders to include escalation factors with bids. PG&E

judge whether to accept or reject such bids in comparison to other RAM bids. IOUs and parties should monitor this approach and recommend changes if necessary.

8.5.4. **Fixed Payments**

IOU revenues can vary widely with sales, and profits can vary widely when marginal revenue (the price charged for the last unit sold) differs from marginal cost (the cost for the last unit sold). Revenue and profit instability have caused particular problems for IOUs when sales decline due to conservation initiatives, efficiency improvements or extremes in weather. We have solved these problems over the years with various regulatory tools.[138]

The same concern can occur with RPS projects. The ratio of fixed to variable costs for RPS projects can vary from high to low.[139] Particularly for those with a high ratio, profits can be unstable if the price (rate) design does not track the cost structure of the seller. Such instability can lead to financing issues, and investors may require a higher rate of return.

IOUs and parties were asked to comment on this in the context of considering the use of fixed payments (e.g., dollars per customer per month) and capacity rates (e.g., dollars per kW per month). Nearly all comments oppose the use of fixed payments asserting, among other things, that fixed payments fail to

---

does not allow use of escalation factors, but achieves the same result by permitting bidders to bid different (escalating) prices each year over the contract term.

[138] For example, we used the Electric Revenue Adjustment Mechanism (ERAM) to decouple sales from revenues for many years, now applied more generically in various revenue adjustment mechanisms.

[139] A solar PV project, for example, may have high fixed costs and low variable costs, resulting in a high ratio of fixed to variable costs. In comparison, a biomass project may have high fixed costs but also high variable costs, resulting in a comparatively lower ratio of fixed to variable costs.

provide reasonable incentives for performance. Only FCE observes that an approach which separately pays the seller's fixed and variable costs "aligns [the] cost recovery mechanism with the nature of the costs."[140]

We decline to adopt a fixed payment scheme as part of the rate design given the overwhelming opposition. We generally agree with parties that fixed payments tend to decouple payment from performance, thereby reducing the incentive for performance. We hear a great deal about the need to provide stability for the RPS industry, however, including stable prices, revenue streams, and regulatory approach to, among other things, facilitate financing. An important part of stability for an RPS project may be aligning changes in its revenues with changes in its costs. This must be balanced with competing ratepayer needs and interests (e.g., low, stable costs for a reliable, safe, clean product). We encourage IOUs and parties to continue to give consideration to the range of rate design issues and bring recommendations, supported by necessary evidence, to our attention as appropriate.

Finally, the ALJ asked IOUs and parties to consider and address five proposed rate designs. We highlight one in Appendix C, including party comments and our observations. We encourage IOUs and parties to continue to give consideration to the tensions identified therein and develop creative solutions where feasible.

9. **Market Elements**

We now turn to a range of proposals on market elements. This includes the number of auctions per year, whether to limit sales to full buy/sell, whether

[140] Pricing Comments at 24.

~~to limit seller concentration, access to information on preferred locations, use of RAM projects in flexible compliance, and other items.~~

In addition, if SCE chooses to apply any capacity from already-executed 2010 RSC program contracts (provided they are approved by the Commission), SCE must detail its net capacity allocation in its initial implementation advice letter. SCE must also propose a schedule for soliciting the remainder of its capacity allocation in RAM solicitations over the next two years.

7.2. ~~9.1.~~ Number of Auctions Per Year

ED proposes a minimum of two auctions per utility per year, staggered between IOUs throughout the year. Parties present a range of views. We require two auctions per year held simultaneously by the three IOUs for the reasons stated below.

DRA, Reid, and PG&E generally support one auction per year, asserting~~, among other things,~~ that multiple auctions are unreasonably costly and time consuming. TURN recommends holding one auction per year at least for the initial two years (asserting that two auctions may be administratively burdensome). TURN says adding a second auction could be based on whether a sufficient number of acceptable bids are submitted. ~~SA~~Solar Alliance recommends a minimum of three auctions per year asserting~~, among other things,~~ that this will enhance competition and developer knowledge of the new market, thereby resulting in lower bid prices. SCE says the number of auctions should be determined in the long-term procurement planning (LTPP) proceeding, and the auctions be held concurrently with other procurement to promote efficiency and administrative cost savings.

One important advantage of a fixed -price FIT is that it is continuously available (i.e., projects can access the tariff at any time). We lose that benefit with

RAM, but in exchange gain potential cost savings from competition. At the same time, we want to minimize the loss of the continuous availability element as much as possible.

We are not persuaded that multiple auctions are unreasonably costly and time consuming. To the contrary, we want the ~~tariff and~~ standard contract to be simplified and easy to implement. We want the auctions and winning bid selections to be streamlined. A requirement of more than one auction per year will provide an incentive for IOUs to accomplish this goal.

Therefore, for the initial roll-out of the program, we require two auctions per year ~~beginning no later than 90 days after the RAM advice letters filed pursuant to this order are effective.~~ . We require the auctions to be held simultaneously by the three IOUs in order to maximize competition. A project may bid into all three auctions. IOUs should propose in their implementation advice letters any methodologies necessary for coordination, including a process for bidders to notify IOUs if they are shortlisted in more than one RAM solicitation.

We expect IOUs, ED, and parties to monitor auctions~~,~~ and make recommendations over time if the number should be changed. We would eventually like the program to be sufficiently routine that auctions may be held even more frequently, if not continuously.~~141~~56

~~141~~ 56 We have encouraged IOUs to explore and propose continuous procurement pursuant to RPS Procurement Plans, and we encourage IOUs to do the same for the RAM. (See D.06-05-039 at 56 regarding annual RPS Procurement Plans.)

7.3. Project Selection

ED proposes that projects submit a price bid and IOUs make selections on the basis of price by selecting the least expensive projects in each product category. ED recommends that projects of the same product type be compared to each other instead of being compared to all renewable products that participated in the auction. ED proposes that the IOUs predetermine the amounts of renewable products they intend to solicit in each auction based on the individual IOU's renewable need. ED offers three examples of products: baseload, peaking as-available, and non-peaking as-available. ED proposes that annual RPS procurement plans specify how much of each product the IOU will procure, with selection based on price and limited by a revenue requirement cap for each product category.[57]

7.3.1. Party Positions

Many parties support selection based on price in order to secure the least-costly products with the maximum benefits of price competition. SCE supports the use of an auction to determine the price for each project, but recommends only one RAM energy product, with the selection not made on the basis of price, but made on the other qualitative and quantitative attributes related to a project's costs and benefits. According to SCE, this method permits the IOU to select the best combination of resource types and deliveries; SCE calls this a "value-based selection process". Parties mention other alternatives, such as selection based on project viability or lottery.

As for ED's recommendation to require three distinct products in each auction, parties offer a range of views. SCE says that each auction should be open to all technologies and not limited by specific types of resource categories,

such as baseload, peaking as-available, and non-peaking as-available. Others, such as FuelCell Energy, GreenVolts, Inc. (GreenVolts), Sierra Club, and GPI, argue for technology differentiation, asserting that this helps preserve production differentiation and encourages resource diversity.[58]

7.3.2. Discussion

We agree with ED that selection should be limited to price. Bid selection based only on price is reasonable because, as recommended by ED, we authorize an IOU to solicit product-specific megawatts in a quantity that reflects an IOU's portfolio need. In each IOU's RAM implementation advice letter, the IOU will choose what portion of their allocated RAM capacity they will solicit from various product buckets. These product buckets are baseload, peaking as-available, and non-peaking as-available. Also, RAM bid prices must be adjusted by an IOU's time of delivery (TOD) factors before the bids are ranked and selected, so that the project's value relative to the IOU's portfolio is considered. As a result, while we do not adopt SCE's proposal to use additional qualitative and quantitative criteria for bid selection, the RAM program does enable a utility to target products that provide specific value to their portfolio. For the initial roll-out of this program, we defer to the utilities to define the products they wish to procure in their implementation advice letter filings. IOUs may choose to procure baseload, peaking as-available, and non-peaking as-available products, or a combination of the products. Once approved, the utilities are to solicit the

---

[57] Pricing Proposal at 8.

[58] GPI recommends cost-of-generation based fixed-price tariffs. (Pricing Reply Comments at 5.) Generation costs vary by technology. A cost-of-generation based fixed-price tariff would therefore require different tariffs by technology.

minimum amounts of products approved through the implementing advice letter.

If an IOU additionally wishes to establish other metrics, such as a seller concentration limit, for the evaluation of RAM bids, it may propose the metric(s) in its implementation advice letter filing for consideration by the Commission. These metrics must fit within the price-only selection framework established for RAM, and would not, for example, include a proposal to add qualitative adders (e.g. transmission cost adders) to the bid evaluation process.

Finally, we provide the IOUs with discretion to reject bids from an auction under two circumstances: there is evidence of market manipulation, or the prices are not competitive. An IOU may reject an entire auction's results based on such an assessment or reject individual bids even before their allocated capacity cap has been reached. In other words, an IOU may evaluate the supply curve of bids received in an auction and assess whether any of the bid prices are unreasonable and uncompetitive relative to the IOU's other renewable opportunities. If an IOU wishes to utilize this discretion, it shall demonstrate in an advice letter filing to the Commission why bids were rejected before the capacity cap was exhausted.[59]

7.4. Use of an Independent Evaluator

DRA has proposed the use of the Independent Evaluator (IE) to oversee the RAM auctions. We adopt DRA's in order to ensure that the competitive solicitations are administered fairly and properly. The IOUs shall use an IE

[59] If an IOU executes contracts from a RAM solicitation, but not sufficient to hit its capacity cap, then it can justify its decision in its Tier 2 advice letter requesting approval of a portion of the projects. If the IOU terminates the entire solicitation, it must file an advice letter with this rationale without the request for approval of any contracts.

consistent with and pursuant to the requirements established in D.07-12-052, as modified by D.08-11-008.

D.07-12-052 ordered the IOUs to develop a pool of at least three IEs to use for all long-term solicitations that involve affiliate transactions or utility-owned or utility-turnkey bids, and for all competitive RFOs. D.08-11-008 modified the circumstances under which an IOU must retain the services of an IE. We believe this requirement is sufficient to ensure a fair and transparent of solicitation. Each IOU shall provide the IE's reports regarding project solicitations in its annual program compliance report to the Commission or in the advice letter submitting the executed contracts.

7.5. Simplified RAM Contract Review

In light of our objective to establish a simple procurement program that reduces transaction costs for the buyer, seller, and regulator, we propose a mechanism for streamlined contract review through a Tier 2 advice letter filing. As discussed above, in the long-term, the amount of generation procured through allowed a simplified review should reflect a utility's need for renewable resources and the comparative costs of various types of generation to meet that need, as identified through a procurement planning process. However, since this methodology is not yet in place, we now discuss an interim approach to authorize a limited amount of RAM procurement through a streamlined contract review process.

The proposed decision would have established a simplified preapproval threshold (SPT) for Tier 1 contract review. The proposed SPT equaled the appropriate MPR plus a 50% premium. This approach would have required IOUs to procure all RAM bids up to the SPT, allowed all procurement below the SPT to utilize the simplified contract review process, and allowed all

procurement at or above the SPT to be filed by Tier 3 advice letter or application. As discussed earlier, parties disputed the legality of imposing a must-take obligation up to the SPT. This issue is rendered moot in this decision because the SPT is eliminated and IOUs are provided the discretion to evaluate whether there is an appropriate price threshold above which bids are not competitive and should be rejected. The simplified contract review mechanism provides that an IOU batch and submit all standardized RAM contracts from an auction in one Tier 2 advice letter for contracts up to the utility's capacity allocation.[60] This will permit simplified review and approval of contracts, which we will have predetermined to be reasonable and prudent for IOU procurement purposes. We note, however, that nothing in this decision diminishes the Commission's authority to reject contracts that the utilities submit based on the RAM program if the Commission finds those contracts are not in the interest of ratepayers. For those contracts that are approved, this mechanism thereby provides assurance of cost-recovery for the IOU.[61]

8. Eligibility

8.1. Eligible Sellers

The original legislation requiring the Existing FIT,[62] and our initial implementation of that program in D.07-07-027, required that a generator serve on-site load and be an existing retail customer of the utility to qualify for the FIT. The requirement has not been carried forward in SB 32, amending the Existing

[60] This capacity allocation may equal an IOU's share of the 1,000 MW, more than its share if requested an approved by the Commission, or less in SCE's case if they adjust their cap with RSC contracts.

[61] § 454,5(d)(2). Cost recovery is predetermined to be reasonable and is assured subject to Commission review of IOU contract administration.

[62] Public Utilities Code Section 399.20.

FIT requirements. It is also not in our existing RPS program (annual bid solicitation), nor is it required in the QF program or as part of the LTPP. We adopt ED's recommendation that the seller need not be a retail customer of the IOU or serve on-site load for consistency with current law and other programs.

8.2. Project and Transaction Size

The Existing FIT program is capped at 1.5 MW. In this proceeding, we asked parties whether or not to increase the eligible project size from 1.5 MW to 20 MW. At that time, § 399.20 limited the program to projects not more than 1.5 MW, and we adopted that as project size limit. The transaction limit in an excess sales scenario was similarly limited.

In contemplating RAM design, we revisit both the appropriate project size, and the appropriate transaction size. In other words, we examine what size projects can participate in RAM and whether projects larger than 20 MW that offset their onsite load can participate in the RAM by selling their excess power up to a transaction size limit. We conclude that the project and transaction limit be 20 MW of nameplate capacity for projects utilizing either the full/buy sell or the excess sales option. This approach is straightforward and easy to implement, and potentially reduces some of the gaming concerns associated with larger projects breaking up transactions in order to participate in the RAM.

8.2.1. Positions

Parties present a wide range of project sizes that should be eligible as part of a new RPS procurement process for small generators. That range varies from retaining the Existing FIT limit of 1.5 MW per project, to an unlimited megawatt size per project. Parties' positions on the appropriate size of the project sometimes depend on whether the price will be fixed in a FIT or subject to a

market mechanism, with several parties advocating fixed FIT prices for smaller projects, and market-based pricing for larger projects.

CARE, AReM, SCE, and others, for example, believe project size should remain at 1.5 MW under a fixed price FIT. However, if based on a competitive market price, CARE supports greater than 3 MW but less than 20 MW.[63] TURN supports 2 MW for a fixed price FIT,[64] or between three and 10 MW if the price is based on an auction.[65] Focusing on a fixed price FIT, PG&E and others argue project size should be limited to 3 MW for several reasons, including recognition of the legislature's most recent guidance in SB 32. SDG&E asserts the risk of system impacts on smaller utilities necessitate a 5 MW limit. ED staff and others recommend a must-take FIT for projects up to 10 MW, with utility discretion to take or reject contracts for projects between 10 MW and 20 MW.[66]

IEP, DRA, Sierra Club, Environmental Council, and others recommend that a streamlined RPS procurement process be available for projects up to 20 MW. GPI and others argue that a must-take FIT should apply to projects larger than 20 MW. GPI prefers a must-take FIT up to at least 60 MW.[67] CEERT says it would eventually "like to see the cap on project size removed so that projects of all sizes may be eligible for the must-take FIT program."[68] LA Community

---

[63] CARE Pricing Comments at 4.

[64] TURN Pricing Comments at 3.

[65] TURN Pricing Comments at 1, assuming SB 32 implementation of a fixed price FIT up to three MW.

[66] In this context, must-take means that the IOU must enter into the standard contract to purchase energy from the generator up to various program caps expressed in MW.

[67] GPI Terms and Conditions Comments at 5.

[68] CEERT Terms and Conditions Comments at 4.

College District does not support a project size cap, believing a FIT should be available to any size project.[69]

8.2.2. Discussion

For all projects, whether utilizing the full/buy sell or excess sales option, we adopt a project size limit of 20 MW. We do this as part of our goal to streamline the entire RPS program for smaller RPS generators where feasible and reasonable. This can be done here for projects up to 20 MW. We adopt this limit for many reasons.

The California Energy Commission (CEC) has repeatedly recommended that we study and implement a FIT for projects up to 20 MW.[70] A 20 MW size limit is also consistent with Commission decisions. We have established certain contract provisions for small sellers because we have found it is difficult for them to bid into a utility request for proposal, and they generally do not have the resources or expertise to negotiate and enter into a bilateral contract. We define the size of those small sellers as 20 MW or less (See D.07-09-040 at 121).

Several existing programs use a 20 MW threshold and those programs influence our decision here. For example, SCE has a standardized contract program for any project using renewable technology up to 20 MW – its RSC program (See D.09-06-018 at 59). SCE says the RSC program addresses difficulties faced by smaller projects (i.e., those up to 20 MW) when they try to

---

[69] LA Community College District Terms and Conditions Comments at 3.

[70] See California Energy Commission 2006, *2006 Integrated Energy Policy Report Update*, CEC-100-2006-001-CMF, January 2007 at E-6; California Energy Commission 2007, *2007 Integrated Energy Policy Report*, CEC-100-2007-008-CMF, January 2008 at 6; California Energy Commission 2008, *2008 Integrated Energy Policy Report Update*, CEC-100-2008-008-CMF, November 2008 at 29; California Energy Commission 2009, *2009 Integrated Energy Policy Report*, Final Commission Report, December 2009, CEC-100-2009-003-CMF at 230.

participate in annual RPS solicitations, and eliminates the need for complex negotiations (See D.08-02-008 at 42-44[71]).

In 2009, PG&E proposed a solicitation as part of its solar PV program for projects up to 20 MW (Application 09-02-019). A 20 MW size potentially has merit in many contexts, and we agree with DRA that PG&E's recommendation that a 10 MW project size limit here is inconsistent with PG&E's proposal for 500 MW of PV installations up to 20 MW for its PV program.[72] We recently approved PG&E's PV program for projects up to 20 MW (See D.10-04-052).

State law requires electrical corporations to have tariffs and standard contracts for purchases of electricity from certain customers up to 20 MW (See § 2840 et seq. regarding combined heat and power). Federal regulations draw an important distinction between QFs at or below 20 MW and those above 20 MW, including exemptions from the Federal Power Act for the smaller QFs, and certain assumptions about the smaller QFs limited ability to access competitive markets.[73] Federal regulations have distinguished between generators at or

---

[71] SCE recently said of its RSC program for projects up to 20 MW: "Through this program, SCE has sought to remove some of the barriers that smaller projects may have had when participating in SCE's annual solicitations. Such barriers have been especially evident for projects with smaller generating capacities. By offering standardized contracts for smaller projects, SCE hopes to increase opportunities for such projects to execute contracts with SCE and contribute to the State's RPS goals." (Advice Letter 2356-E (July 1, 2009) at 3.)

[72] DRA Terms and Conditions Reply Comments at 7.

[73] 18 CFR 292.309(d)(1) establishes a rebuttable presumption that a QF with capacity at or below 20 MW does not have nondiscriminatory access to the wholesale electricity market. Also see 18 CFR 292.601 regarding certain exemptions from federal and state law for QFs at or below 20 MW.

below 20 MW and those above 20 MW for purposes of interconnection requirements.[74]

SDG&E and several parties argue for a lower project size limit, asserting that large projects may create significant problems with interconnection, grid system stability, or other concerns. Among other things, SDG&E states:

> As project size increases to 5 MW, the probability that system upgrades will be required also increases. As shown in the illustrative example in Attachment A [to SDG&E's terms and conditions Comments], system upgrades that could be required to accommodate projects sized greater than 5 MW would be prohibitively expensive.[75]

Solar Alliance and Vote Solar counter that prohibitive costs deter developers:

> Many of the IOUs' concerns fall by the wayside when one considers SDG&E's acknowledgement (comments at p. 11) that generators are responsible…for interconnection and distribution upgrade costs. In other words, interconnection costs…are likely to be a potent deterrent for developers to interconnect a system beyond what the interconnected distribution system can handle without significant upgrades. This more than adequately addresses SDG&E concern regarding the maximum size limit for projects in SDG&E's service territory. As SDG&E acknowledges (comments at p. 11), '[p]rojects sized above 5 MW are likely to require significant system upgrades…making such projects poor candidates for the FIT Program.'[76]

We are not convinced that project size must be limited because of system reliability or interconnection cost concerns. Each project, regardless of size, must

---

[74] For example, see SCE 2009 RPS Procurement Plan Request for Proposals at Section 7.04.

[75] Terms and Conditions Comments at 5-6.

[76] Joint Terms and Conditions Reply Comments at 3.

successfully navigate the interconnection process, including cost allocation, before it can be interconnected. Synchronized operation is not permitted unless and until the system may be operated safely, and projects that will cost too much to interconnect will not be pursued. The evidence demonstrates that existing interconnection requirements adequately address these concerns for all projects, including those 20 MW or less. For all these reasons we find smaller projects, defined here as 20 MW or less, should be eligible for the new RAM procurement program adopted here. IOUs should proposed in their bid protocols how to prevent sellers from breaking up or subdividing larger projects to circumvent the 20 MW project size limit.

8.3. ~~9.2.~~ Full Buy/Sell or Excess Sales

~~The current FIT permits sellers to elect either full buy/sell or excess sales. (See D.07-07-027 at 33-38.) ED proposes that expanded FIT be available only as a full export tariff (full buy/sell).[142]~~ PG&E, SCE, and SDG&E must offer Existing FIT customers the choice of selling electricity under an arrangement of either (a) full buy/sell or (b) excess sales(See D.07-07-027 at 33-38[77]). In a full buy/sell transaction, a renewable facility would sell 100% of its generation to the utility. In an excess sales agreement, a facility would first offset its onsite load and sell its excess generation to a utility.

~~Parties offer a range of views. CALSEIA, SCE and DRA support the full export (full buy/sell) approach. PG&E, TURN, CEERT, GPI, FCE, Sustainable Conservation, SFUI, RR and Environmental Council support either (a) excess~~

~~[142] March 2009 Proposal at 9.~~

[77] The other four utilities (PacifiCorp, Sierra, Mountain Utilities, Bear Valley) must offer to purchase pursuant to full buy/sell, and may offer to purchase via excess sales.

~~sales or (b) the customer having the choice of either full buy/sell or excess sales in most, if not all, cases.~~

~~We continue the existing approach of letting the customer choose either full buy/sell or excess sales. This includes the existing requirement that an excess sales Power Purchase Agreement (PPA) is for all excess generation from the facility that is not used on-site.[143] We do so for several reasons.~~

~~The choice of either full buy/sell or excess sales has been available to QFs since 1979. It remains a permissible option in FERC QF rules. No evidence is presented that this policy has been unworkable over the last 30 years.~~

~~In 2007, we adopted both options for the FIT. No evidence shows this policy to have been unworkable. The reasons for its adoption in 2007 remain valid today (e.g., optimal resource development when retail rates differ from avoided/incremental costs while at the same time providing equitable treatment to stakeholders).[144]~~

~~We dismissed SCE's application for rehearing on this subject. In doing so we concluded that the two sales options are consistent with the plain language of the statute. We also said that the two options further the statutory intent of promoting reasonable development of renewable resources to meet multiple state objectives.[145] The two sales options continue to do so, and should be adopted in the RAM to facilitate the same objectives.~~

~~[143] A seller, for example, may not sell separate portions of generation to multiple programs or in multiple PPAs.~~

~~[144] See D.07-07-027 at 36-37.~~

~~[145] D.08-02-010 at 6-8. Those objectives include promoting stable electricity prices, protecting public health, improving environmental quality, stimulating sustainable economic development, creating new employment opportunities, and reducing dependence on imported fuels. (§ 399.11(b).)~~

ED ~~recommends limiting sales to~~proposes that the RAM be available only as a full buy/sell transaction, asserting that the excess sales option fails to provide the IOU with sufficient certainty regarding the expected output from the project and undermines the IOU's ability to conduct long-term ~~renewables~~procurement planning.[78]

8.3.1. Party Positions

CalSEIA, SCE, PG&E,[79] and DRA support the full buy/sell approach. Solar Alliance, IEP, TURN, CEERT, GPI, FuelCell Energy, Sustainable Conservation, SFUI, Redwood Renewables, and Environmental Council support having the option of either (a) excess sales, or (b) the customer having the choice of either full buy/sell or excess.

8.3.2. Discussion

We are convinced by GPI, TURN, and others that ~~this~~ED's concern is unfounded. GPI correctly contends, for example, that the effect on the integrated electrical system is the same regardless of the type of sale agreement.~~146~~[80] That is, the renewable generator output and the host-site load will exhibit the same levels of variation despite the type of sale arrangement with the IOU, and there is no evidence to show that the output and load are influenced by the type of sales arrangement.~~147~~[81] TURN correctly states that IOUs are capable of reasonably accurate forecasts and have routinely made such calculations in many

---

[78] March 2009 Proposal at 9.

[79] PG&E supported the excess sales option in the March 2009 Proposal, but changed its position to supporting the full buy/sell option in its comments on the proposed decision.

~~146~~[80] Integrated system planning, for example, can be successfully performed whether electricity generation is on the "customer side" or the "utility side" of the meter.

~~147. T&C~~[81] Terms and Conditions Comments at 3.

Commission proceedings. TURN concludes that: "There is no specific reason why providing compensation for net excess sales complicates such forecasts or undermines the accuracy of long-term resource planning."[148]82

9.3. Seller Concentration

The ability of RAM to produce cost savings (compared to a fixed rate or other pricing option) depends largely on the degree of competition among bidders. To address this, ED proposes that the revenue requirement cap be coupled with a seller concentration limit to ensure market competition. In particular, ED recommends that no one seller be permitted to contract for more than 50% of the capacity cap or revenue cap in each auction (across all bids).[149]

9.3.1. Party Positions

Parties offer a range of views. FITC recommends the cumulative awarded bids from a single bidder or equipment manufacturer not exceed 20% of total capacity in any auction. In support, FITC contends that 50% is too much concentration. The Commission should start with rules that clearly encourage competition, according to FITC, and may modify or relax the rules over time if necessary based on evidence.[150]

GreenVolts states that competition should exist both among developers and companies supplying the equipment. At least for a transitional period of five years, GreenVolts says no entity should be the source of equipment or project developer for more than 20% of the winning projects in each auction.[151]

---

[148] T&C82 Terms and Conditions Comments at 6.

[149] August 2009 Proposal at 9.

[150] Pricing Comments at 9.

[151] Pricing Comments at 9-10.

~~TURN recommends a seller concentration limit of 30%. In support, TURN says a percentage lower than 50% can both (a) prevent larger entities from gaining significant market share by virtue of their superior financing or balance sheets and also (b) prevent an entity from bidding unrealistically low prices for multiple projects that cannot realistically come to fruition.[152]~~

~~FCE recommends a seller concentration cap at a level inversely proportional to the number of unaffiliated participants in each technology-specific group, adjusted in each auction to reflect the number of unaffiliated bidders participating in the previous auction round.[153] SFUI recommends that no one company or individual be permitted to own or operate more than 9 MW, thereby, according to SFUI, creating a potential of 83-84 projects out of a 750 MW allocation.[154]~~

~~PG&E asserts there is no assurance that limiting the number of contracts will result in selection of the most attractively priced projects. PG&E suggests the Commission allow IOUs to rely on their individual credit policies, which are designed to address counterparty concentration risk.[155]~~

~~Axio recommends no seller concentration limit, asserting both that (a) a limit will be challenging to enforce and (b) delivery of the lowest cost renewable power (even if only from one seller) is a more relevant program objective than limiting seller concentration. Axio says seller concentration for mature, viable~~

~~[152] Pricing Reply Comments at 9.~~

~~[153] Pricing Comments at 14.~~

~~[154] Pricing Comments at 7.~~

~~[155] Pricing Comments at 11-12.~~

~~projects should not be discouraged, and a project maturity criterion will be a more effective program tool.[156]~~

~~9.3.2. **Discussion**~~

~~We agree with PG&E and Axio, and decline to adopt a seller concentration ratio. A specific concentration ratio does not guarantee that IOUs will secure low cost power. It would require rejection of all bids when only a few bidders participate (e.g., two bidders with a 50% ratio; five bidders with a 20% ratio). This rejection would be required even when all prices are below a reasonable benchmark (e.g., MPR) and it would otherwise be reasonable to select those projects.~~

~~A seller concentration test adds complexity that is unlikely to provide reasonable offsetting protection. For example, entities may hide behind corporate structures that make determination of concentration ratios both difficult and meaningless. Measurement of concentration is not straightforward. It may include not only bidders but also manufacturers. According to some, it requires adjustment for the number of unaffiliated participants by technology group in a prior auction round. The measurement requires definitions (e.g., bidders, manufacturers, affiliates, technology groups), data collection, and a number of calculations. This introduces the potential for errors and disputes. It substantially increases program complexity.~~

~~Protection of ratepayers against an adverse outcome is accomplished more simply and directly via the capacity cap and SPTs adopted herein. That is not to say that competition is not important. It is. In fact, it is a fundamental and vital premise that underlies the entire RPS structure, not limited to but including~~

~~[156] Pricing Comments at 10.~~

RAM. We deal below with measuring and enforcing competition.[157] We are not convinced at this time, however, that the possible benefits of a specific seller concentration test outweigh potential costs, complexities and disputes.

9.4. Preferred Locations

ED proposes that IOUs make information available on preferred distribution substations based on available capacity of that substation, updated on a real-time basis.[158] This will significantly assist projects locate in preferred locations, according to ED, thereby avoiding potential distribution and transmission upgrade costs and delays.

9.4.1. Party Positions

Parties generally agree with the need for and desirability of this data, but present a range of views on feasibility and cost.

SCE proposes providing potential project areas (in the form of a zip code and geographic area bounded by landmarks or specific streets), along with an estimate of approximate available distribution capacity. SCE states that it will update this information as often as possible (including prior to each auction). SCE says this is the same as its solar PV Program auction proposal.[159]

PG&E believes a real time update may require significant investment in communication platforms and resources for system maintenance while not

---

[157] We suggest the use of seller concentration as one of several potential measures of market competition in our discussion below of the data necessary to measure competition. It is identified there as one potential measure, not as a direct factor in acceptance or rejection of bids.

[158] August 2009 Pricing Proposal at 9.

[159] Advice letter 2364-E (process and criteria for evaluating IPP PV offers) resulting from D.09-06-49 (approving SCE's solar photovoltaic program). See SCE Pricing Comments at 7-8.

providing significant benefits, particularly if the auction is held only once per year. PG&E recommends a working group to study the issue.[160] SDG&E says it is not practical to determine preferred substations and update this list in real-time.[161]

SFUI says IOUs should provide this data on a real time basis, arguing that many cities and water authorities have their water and sewer distribution maps on the internet for immediate access by construction professionals. FITC states that Ontario Power Authority maintains two reports with needed FIT interconnection data, updated weekly. FITC recommends the Commission require each IOU to prepare and maintain an interconnection data report following a specified format, updated in real-time.[162] Recurrent supports ED's proposal with updates as often as auctions occur (not real-time) with information at the zip code level (but not in more detailed to avoid a land rush by developers).[163]

9.4.2. Discussion

No party argues that substation data is undesirable, or that it is unnecessary for making informed interconnection decisions. The real issues are the type and amount of data, and frequency of updates.

We recognize that it may be infeasible for an IOU to provide information on all substations during the initial rollout of this program given the large service areas of each IOU. Therefore, an IOU may initially focus on what it determines are "preferred" areas. Preferred areas are likely to be those near load where the

[160] Pricing Comments at 12.

[161] Pricing Comments at 7.

[162] Pricing Comments at 8-9.

~~IOU has a reasonable expectation of surplus transmission and/or distribution capacity.~~

~~The data must be sufficiently detailed to be useful. We agree with parties who assert SCE's proposed "project areas" (zip code and area bounded by landmarks or streets) fails to provide sufficient detail. To be most useful to potential projects, IOUs must provide data at the substation or circuit level. IOUs must have this information in order to execute their responsibilities for daily operations, system scheduling, and infrastructure planning to meet current and future demand. For the initial rollout, we require IOUs to provide information regarding available capacity at the substation or circuit level, or show why it cannot be provided. If unable to initially provide this level of detail because the information is not available, each IOU must provide the data at the most detailed level feasible, and work to increase the precision of the information over time.~~

~~We do not require real-time provision of, and updates to, this information since auctions will be held only every 180 days. Rather, we require that the information be provided as soon as possible for the initial auction (but no later than 45 days in advance of the initial auction), and updated no later than 90 days in advance of the each subsequent auction. If it has the ability to do so, we expect each IOU to update this information more frequently. We also expect each IOU to pursue all cost-effective improvements to provide this data at a more detailed level with more timely updates.~~

~~We anticipate that each IOU will, over time, provide system-wide information. To not do so requires IOUs to continuously determine what are and~~

~~[163] Pricing Comments at 9.~~

~~are not "preferred" areas. That involves judgment better left to stakeholders. IOUs should eventually provide reasonable data on all areas, and let developers, along with IOUs and other stakeholders, decide if it makes sense to interconnect at various locations.~~

~~We recently adopted similar requirements with respect to SCE and PG&E PV programs.[164] We there expect each IOU to make reasonable initial disclosures, and implement improvements over time. That same approach is reasonable for the RAM. Moreover, we expect SCE and PG&E to simultaneously incorporate data and improvements with respect to their PV programs into the RAM program, and vice versa.~~

~~9.5. Project Milestones~~

~~ED proposes a requirement that project sponsors submit a project development milestone timeline to the IOU upon signing the FIT contract, and provide quarterly progress reports to the IOU. The IOU and Commission can thereby monitor development progress, according to ED. ED recommends the only milestone with a resulting consequence is the commercial operation date (COD). ED proposes the COD must be within 18 months of contract execution, subject to one possible six-month extension, and failure to meet the COD deadline results in contract cancellation.~~

~~No party presents material objection to the requirement for an informational project development milestone timeline submitted upon contract execution, with quarterly updates thereafter. We adopt this requirement.~~

~~We agree with ED and parties that the 18-month milestone should be meaningful, and we decline to adopt other enforceable milestones. We address~~

~~[164] D.09-06-049 at 40. Resolution E-4299 at 5 - 7. D.10-04-052 at Ordering Paragraphs 9 and 10.~~

below the specifics of the 18-month criterion and permissible limited extensions. The result of failing to meet the COD (at the end of 18 months or other authorized extension) in the RAM is contract cancellation.

9.6. Flexible Compliance

ED proposes that an IOU not be allowed to use RAM contracts with projects in the size range of 10 to 20 MW for purposes of flexible compliance (i.e., permissible deferral of some RPS procurement obligations).[165] This is part of ED's recommendation for different treatment between projects up to 10 MW and those from 10 MW to 20 MW. ED says IOUs need not submit an advice letter for projects up to 10 MW, similar to the process with the existing FIT for projects up to 1.5 MW. For projects from 10 to 20 MW, ED recommends IOUs submit a Tier 2 advice letter that will become effective in 30 days, unless suspended. ED says these larger projects should not count for flexible compliance since the Commission will not have an opportunity to review their viability.[166]

IOUs object to ED's proposal because it creates different value for contracts based on size.[167] We agree, and decline to adopt ED's proposed flexible compliance treatment for several reasons.

First, our adopted program does not differentiate between projects that are below 10 MW and those from 10 to 20 MW. Neither should the treatment of flexible compliance.

---

[165] LSEs must meet annual procurement targets as part of their obligations under the RPS program. Flexible compliance permits an LSE to apply excess procurement in one year to subsequent years, or inadequate procurement in one year to no more than the following three years. (§ 399.14(a)(2)(C).)

[166] March 2009 T&C Proposal at 5.

[167] See, for example, PG&E T&C Comments at 6-7; SDG&E T&C Comments at 17-18; SCE T&C Reply Comments at 4.

Second, the adopted program includes the same viability requirements for all projects (e.g., site control, developer experience). This largely addresses ED's concern.

Third, we require below that all projects be submitted by advice letter for our consideration. An advice letter filing provides the Commission and the public with the opportunity for review and consideration of any contract that merits particular assessment.

Finally, we agree with IOUs that all RPS contracts should be eligible to be considered for flexible compliance.[168] To do otherwise will place a different (and likely lower) value on contracts ineligible for flexible compliance. We see no reason to treat contracts for projects between 10 and 20 MW, or submitted by Tier 2 advice letter, any differently.

9.7. Wait List

The existing FIT allocates an IOU's FIT capacity to projects on a first-come first-served basis. (See D.07-07-027 at 11-12.) When the allocated capacity is fully subscribed, the IOU develops a wait-list of interested projects. ED initially proposed the expanded FIT include a wait-list for interested projects developed on a first-come first-served basis.[169]

---

[168] An LSE may earmark the energy from a signed contract, or a pool of contracts, to fill part, or all, of a forecast future deficit. Earmarking must be accomplished by certain deadlines for the energy to apply to the forecast deficit within the following three years. For purposes of flexible compliance, FIT contracts work the same way as contracts that originate from RPS solicitations or bilateral negotiations. As long as the FIT contract is executed by the earmarking deadline, and is scheduled to deliver within three years of the deficit year, it can be used for flexible compliance.

[169] March 2009 Proposal at 7.

We decline to adopt a wait-list provision. The wait-list is reasonable when the price is fixed in the tariff and supply (i.e., the MW capacity from interested projects) exceeds demand (i.e., the allocated MW capacity). A wait-list is unnecessary when the allocation is based on price via a RAM. An unsuccessful project may simply submit a bid in the next RAM auction or pursue any other available option (e.g., annual bid solicitation, bilateral negotiations).

9.8. Relationship to Voluntary and Other Programs

SCE recommends that the 1,000 MW program cap include the existing FIT (up to 1.5 MW, subject to expansion to 3 MW) plus already executed or about to be executed contracts through an IOU's voluntary programs (e.g., SCE's RSC program, solar PV program).[170] VSI and SA disagree.[171] We decline to make the 1,000 MW program cap inclusive of voluntary and other programs for the reasons explained below.

SCE says IOUs should be encouraged to propose voluntary programs or take other action without enforcement. SCE asserts that sellers should not be penalized for responding to market needs and proactively creating other opportunities to meet RPS goals. We do not disagree.

SCE fails, however, to convincingly show how not comingling RAM with other mandatory and voluntary programs penalizes an IOU. To the contrary, RAM is simply another tool to help IOUs and the state reach legislatively mandated targets and administratively set goals. We have recognized SCE's initiative and innovation with its RSC program, and encouraged other IOUs to adopt the same approach. (See D.09-06-018 at 62.) We continue to encourage

[170] Pricing Comments at 9.

[171] VSI Pricing Reply Comments at 6; SA Pricing Reply Comments at 4.

~~IOUs to be creative and vigorous in program development, administration and execution, including both required and voluntary programs.~~

~~We also agree with VSI that SCE's recommendation reduces the size of the RAM program. It does so in unknown ways since voluntary programs contain T&C that differ from the RAM protocols adopted here. This is also true for capacity enrolled in other related programs (e.g., CSI, SGIP, net metering, utility PV). Inclusion of capacity from these other programs in the 1,000 MW capacity for the RAM unnecessarily confuses different programs or tariffs and will complicate data analysis of the RAM program. Thus, the capacity enrolled in any other program or tariff will not be included in the 1,000 MW RAM program cap.~~

~~9.9. FERC Certification~~

~~ED notes that for SCE and SDG&E the current FIT contains a requirement that the project be certified at FERC as a QF. ED proposes that there be no such requirement for the RAM.~~

~~We agree. The RPS program is not the QF program. (§ 399.15(e).) RAM is not a QF program. We decline to impose a QF requirement on RAM.~~

~~This does not prevent a project from certifying as a QF. A project may certify as a QF if it wants (and projects 1 MW and less may be QF certified without action), but it need not do so to be eligible for RAM.~~

~~Our only requirement is that each project ultimately receives necessary certification from each relevant government agency (e.g., certified environmental impact report from a lead agency). That is, each project must satisfy all applicable federal, state and local laws and regulations. For RAM, that does not include being a QF.~~

9.10. **Conveyance of RECs**

The existing program provides that RECs are transferred to the IOU in relationship to the amount of the purchase. For full buy/sell, the IOU buys RECs coincident with the entire generation output. For excess sales, the seller retains RECs for the electricity it uses itself, and the IOU acquires RECs coincident with the excess energy it purchases. (See D.07-07-027 at 33-35.) ED proposes no change relative to the transfer of RECs. We agree.

This treatment of RECs is consistent with the legislative structure of this program, both now and as amended by SB 32.[172] Further, transfer of RECs coincident with the purchased energy (either total energy production or excess only) continues to be reasonable for the reasons explained in our 2007 order. (*Id.*) There is no reason to treat the RAM program differently.

We also decline to complicate these transactions by separating the renewable energy credit (REC) from the energy. Otherwise, for example, the auction will have additional complexity, with bidding for potentially up to nine items (firm, non-firm peaking, non-firm non-peaking electricity for products that are bundled, REC only, and energy without REC). One guiding principle is to keep the RPS Program reasonably simple. This includes the initial rollout of RAM. We may consider separating the REC from the energy in the future, but do not do so here.

10. **Contract Terms and Conditions**

Because there is no technological impediment, and because it meets certain state policy goals, we continue the approach of the Existing FIT by allowing the generator to choose either full buy/sell or excess sales. First, the choice of either

[172] See § 399.20(f), which became § 399.20(h) on January 1, 2010. Also see the REC issue discussion in D.07-07-027 at 33-34.

full buy/sell or excess sales has been available to QFs since 1979. No evidence has been presented that this policy has been unworkable over the last 30 years. Second, in D.07-07-027, we adopted both options for the Existing FIT.[83] Thus, we allow both the full buy/sell and excess sales transactions for the RAM. For both types of transactions, the full project capacity should apply to an IOU's capacity cap.

8.3.3. Location of Facilities Eligible For The RAM

Parties take a wide variety of positions on where a project must be located to be eligible for the RAM – from IOU service territories to the entire CAISO control area. The IOUs support the geographic restrictions of the Existing FIT, wherein generators sell to their interconnecting utility. ED recommends that projects eligible for the RAM program be located within the CAISO control area to facilitate interconnection of projects that efficiently utilize California's distribution and transmission system.

The proposed decision would have allowed any RPS-eligible generator to bid into RAM. That is, all facilities interconnected to the Western Electricity Coordinating Council (WECC) could participate in any of the IOUs' RAM auctions. No parties supported this position.[84] Most parties support limiting eligibility to projects located within California, to California's distribution system, or to a utility's service territory. In support of requiring distribution-level interconnection, TURN notes, "The

[83] We dismissed SCE's application for rehearing of D.07-07-027 on this subject. In doing so, we concluded that the two sales options are consistent with the plain language of the FIT statute. We also said that the two options further the statutory intent of promoting reasonable development of renewable resources to meet multiple state objectives. The two sales options continue to do so, and should be adopted in the RAM to facilitate the same objectives.

[84] Specifically, Axio, DRA, CARE, FCE, FIT Coalition, enXco, Recurrent, SFUI, SDGE, Solar Alliance, and TURN oppose a WECC-wide approach.

original purpose of the RAM was to provide streamlined market opportunities for distributed generation projects connecting to preferred locations within IOU service territories."[85]

We agree that RAM eligibility should be limited to the utilities service territories. RAM provides a specific and well-defined value to ratepayers because small system-side RPS projects that connect to utility service territories incur none of the additional costs associated with some other forms of renewable generation. For example, these expenses may include costs to construct new transmission lines for more remote generation facilities and the expense of firming and shaping transactions for generation that can not be delivered directly to a CA balancing authority area. If projects located outside IOU service territories were included in RAM, then the price-only project selection criteria may not be applicable. Instead, IOUs may have to add transmission and/or firming and shaping adders to the market valuation of bids to evaluate the projects on an apples-to-apples basis. Thus, RAM enables more streamlined RPS program administration by requiring bid evaluation based on price only, which does not allow for other qualitative adders which are used to assess and rank bids' value in the annual RPS solicitations.

Accordingly, we will allow any projects located within PG&E's, SCE's, and SDG&E's service territories to participate in RAM and bid into one or more of the IOUs' RAM auctions. If a project is selected in more than one auction, however, it must notify all affected IOUs which one shortlist it will accept within 10 days of its notice that it was selected in multiple auctions.

Finally, we reject a Sierra Club proposal to give community choice aggregators (CCAs) and energy service providers (ESPs) the right of first refusal

[85] TURN Comments on PD, page 7.

for electricity from an RPS project in their service areas.[86] We seek to promote, not limit, competition. Tipping the scale in favor of CCAs or ESPs would unreasonably constrain the competition upon which this market is premised.

9. RAM Standard Contract

9.1. Contract Negotiations

ED proposes that RAM standard contract terms and conditions not be negotiable. Similarly, bid prices should not be negotiable.[87] We agree.

We streamline procurement with the RAM by adopting a standard, non-negotiable contract for each IOU, a program capacity cap, a market mechanism to determine contract price, and other standardized protocols. The result is to provide IOUs, project developers, and the Commission a simplified approach to accessing a market segment that can contribute substantially to meeting the state's RPS, GHG, and other goals. This makes it relatively easier and less costly for all stakeholders.

We decline to allow negotiations within the RAM since this will add time, cost, and complexity to the RAM program. Buyers and seller in this market segment have other opportunities that permit negotiations if and when necessary, in the form of the annual RPS solicitation. In this context, it is reasonable to make the RAM program "take-it-or-leave-it" (non-negotiable). To allow for contract negotiations is, in our view, in conflict with the goals of this program which is to provide a streamlined approach to renewable procurement for smaller scale RPS projects.

---

[86] Terms and Conditions Comments at 12.

[87] August 2009 Proposal at 9.

9.2. RAM Contract Terms and Conditions

ED proposes that each IOU start with its Existing FIT contract and add or amend terms as needed to develop RAM, with the three IOUs having consistent terms and conditions for the new terms. ED recommends that a uniform standard contract for all three IOUs be required over time. Parties dispute the need and desirability of uniformity, with IOUs generally in opposition and some parties in support.

While we appreciate ED's desire for uniformity across each of the IOUs' RAM contracts – with one uniform contract the goal – we decline to require such rigid uniformity here. We will allow each IOU to develop its own standard contract, which will be non-negotiable and standard for all winning bidders in a specific RAM auction. We also decline to identify which contract each IOU should start with in developing a standard RAM contract. We do strongly encourage the IOUs to begin with an existing standard contract that is simple, currently in use, and that has been vetted through a stakeholder process. Each IOU shall include its proposed standard contract as part of its advice letter filing implementing RAM, as described in Section 12.1 below. While we do not mandate a uniform contract, there are some basic elements within those contracts that we require to be the essentially the same, as described in the section 9.3 below.

~~Standard contract provisions will include several necessary program design-related items discussed above. In addition, we~~We now discuss specific contract terms and conditions raised by ED and addressed by parties. If not addressed in this decision, we intend to defer to the IOUs on contract terms and conditions, subject to Commission approval through an advice letter.

~~10.1. Length of Time to COD~~

~~10.1.1. Background and Positions~~

9.2.1. 18 Month Commercial Operation Date

The ~~existing~~Existing FIT provides that a project must be operational within 18 months or the contract is subject to termination. Termination is not automatic. The IOU must provide notice and opportunity for parties to address termination before termination becomes effective. If unable to reach agreement on a reasonable schedule, the IOU may move forward with termination. (See D.07-07-027 at 38-40.)

For RAM, ED proposes automatic contract termination after 18 months, with developer forfeiture of the proposed project development security deposit. A one-time six-month extension may be permitted, according to ED's proposal, if the project can successfully demonstrate the cause of the delay is due to regulatory processes outside of its control ~~(e.g., transmission permitting, generator~~such as permitting or interconnection ~~application with a showing that necessary documents were filed, and fees paid, on time)~~delays not caused by the developer. ED recommends that delay due to business risk ~~(e.g.~~, such as lack of financing~~,~~ or equipment delivery delay~~)~~ not be an acceptable justification for the granting of an extension. If terminated, ED says the project may participate in another RPS opportunity, such as the next RAM auction or annual competitive RPS solicitation~~, or may negotiate a bilateral contract.~~[173].[88]

9.2.1.1. Party Positions

Parties offer a range of views on the proposed 18-month commercial operation date, and possible extensions. CEERT and some parties support ED's proposal in part or whole. CALSEIA says projects over 5 MW may need more

[173] ~~August 2009~~[88] Pricing Proposal at 8-9.

time to obtain permits, and recommends considering a longer timeframe combined with project milestone requirements.[174]89 FCEPG&E suggests specific times frames, with extensions at the discretion of the IOUs, but proposes that termination only occur when there are true constraints, such as the program cap or transmission or distribution limits.[90] FuelCell Energy does not object to ED's proposal as long as an appropriate force majeure clause covers events outside the parties' control.[175]91 GPI opposes the 18-month provision, asserting it is unnecessary and harmful unless the 1,000 MW program cap is a realisticbinding constraint.[176] that is actually limiting other projects' participation in RAM.[92]

10.1.2. **Discussion**

We think there is merit in a relatively strict length of time provision for RAM, not unlike in the exiting FIT. This streamlines RAM administration, and makes scarce transmission and distribution resources available when they are otherwise tied up in delayed projects.

Strict administration must be balanced with other considerations, however. The future is never certain. Should a legitimate delay occur, a formulaic approach will be harmful to an otherwise viable project and result in higher costs.[177] Loss of, or higher cost relative to, an otherwise viable project is not only detrimental to the project but also to the RPS program and California's

---

[174] T&C89 CALSEIA Terms and Conditions Comments at 4.

[90] PG&E Terms and Conditions Comments at 8.

[175] T&C91 FuelCell Energy Terms and Conditions Comments at 3.

[176] T&C Comments at 4.

[92] GPI Terms and Conditions Comments at 4.

[177] The project forfeits its development security deposit, for example.

~~RPS stakeholders. The requirement need not be blindly applied if neither the RAM 1,000 MW program cap nor T&D limitations are actual constraints.[178]~~

~~We are persuaded by PG&E that the approach which best balances competing recommendations and allows application only when there are true constraints is adoption of a timeframe for termination, with further extensions up to the IOU.[179] Therefore, we adopt an 18-month timeframe, with one or more potential six-month extensions. This adopts ED's proposed one-time six-month extension, but also permits others if reasonable.~~

~~We permit each potential extension to be at the discretion of the IOU in increments of six months. The IOU must provide notice and opportunity for contracting parties to address termination, just as with FIT (existing). We expect IOUs to award an extension only when the reasons for extension have merit, and the T&D or 1,000 MW program limits are not binding constraints. As PG&E says, this approach will allow a viable project close to commercial operation to continue to completion without penalty.[180] This approach will also help a project avoid increased initial financing costs due to the risk of automatic termination outside of the project's control. On the other hand, it will make T&D resources available when T&D is an actual constraint and a project is seriously delayed.~~

~~[178] The MW program limit would be a constraint, for example, if projects remain at a price below the SPT but selection is limited by the program capacity limit. In this case, the IOU should be more cautious about granting an extension since other price competitive projects are available.~~

~~[179] T&C Comments at 8.~~

~~[180] The penalty, for example, would be forfeiture of deposits, and incurrence of additional cost and risk of another RAM auction or annual bid solicitation.~~

~~We agree with Sierra Club California that the criteria for a six-month extension should be broadened beyond those proposed by ED.[181] We would not, for example, expect an IOU to limit the reasons for an extension to regulatory delays. Rather, an IOU might be willing to consider any delay legitimately outside the control of the developer. An IOU should terminate a contract at the end of 18 months (or the end of an authorized extension), however, if the project fails to adequately demonstrate the merits of an extension.[182]~~

~~We expect ED and parties to monitor IOU extensions, and take this into consideration as part of future recommendations relative to IOU administration of the RPS program. For example, one or more six-month extensions may be reasonable when they help an IOU reach program targets and goals.[183] Unreasonably denying extensions when neither the program cap nor T&D are true constraints, however, might be viewed unfavorably by parties and the Commission (absent compelling reasons to the contrary) if an IOU is otherwise subject to a penalty for failing to reach its annual procurement target.~~

~~We decline to adopt other recommendations. For example,~~ IEP contends that ED's recommended strict 18-24 month requirement will limit eligibility to projects that (a) are already interconnected or have strong assurances that no

---

~~[181] T&C Comments at 10.~~

~~[182] Examples of delay outside the developer's control with appropriate justification might be: regulatory delay but the project must show that it filed applications timely, paid fees timely, and is responsibly pursuing the application; financing delays but the project must show it applied for funds timely and is responsibly pursuing financing; equipment delivery delays but the project must show that it ordered equipment timely and continues to responsibly seek equipment acquisition.~~

~~[183] For example, two six-month extensions granted by the IOU may be reasonable if a project is then brought on line within the three-year flexible compliance period.~~

upgrades will be required and (b) have already completed permitting. IEP says this will considerably shrink the universe of potential projects because developers will be required to make significant financial expenditures before they can sign a contract. Moreover, few lenders will agree to finance a project that will lose its contract if it encounters even ordinary construction delays. IEP suggests the cure for these concerns is to allow the project 18 months after contract signing to begin material on-site construction.

In the alternative, IEP suggests that technology-specific timelines may be established in recognition of the different degrees of construction and permitting complexity associated with different renewable technologies.

9.2.1.2. Discussion

We think there is merit in a strict length of time provision for RAM, not unlike in the Exiting FIT. This streamlines RAM administration and attracts projects that are more viable because they are further along in the project development process. We find that the best approach is to set meaningful time limits, subject to one justifiable extension. Therefore, we adopt an 18-month timeframe, with the potential for one six-month extension. The 18-month deadline begins upon contract execution between the IOU and the seller. We expect the IOU to limit the reasons for an extension to regulatory delays outside of the developer's control. In order to grant an extension due to regulatory delays, the project, for example, must show that it filed applications timely, paid fees timely, and is responsibly pursuing the necessary applications. An IOU should terminate a contract at the end of 18 months if the project fails to adequately demonstrate the merits of an extension.

We expect ED and parties to monitor IOU extensions, and take them into consideration as part of future recommendations relative to IOU administration of the RPS and RAM programs.

We ~~appreciate IEP's creativeness, but we are not persuaded~~do not adopt IEP's proposal that we move the critical milestone deadline from commercial delivery to the commencement of material on-site construction. The record does not contain a definition of material on-site construction, and we decline to develop one. Disputes are likely even if the term is defined. ~~Further, there can potentially be legitimate delays before the beginning of material on-site construction.~~ Therefore, changing the deadline from commercial operation to material on-site construction does not resolve the issue.

~~In the alternative, IEP suggests that~~Similarly, we decline to adopt technology-specific timelines ~~may be established in recognition of~~that recognize the different degrees of construction and permitting complexity associated with different renewable technologies~~. Again, we are not persuaded~~. The establishment of any timeline requires judgment, and legitimate delays can occur relative to any timeline. Technology-specific timelines do not resolve the issue.

~~The adopted approach provides a reasonable balance. It keeps developers from clogging the project queue but provides managed flexibility in recognition of the increased size and complexity of the candidate projects. It is reasonably parallel to the existing program, with the addition of potential extensions for good cause in six-month increments at the IOU's discretion.~~

9.2.2. ~~10.2.~~ Development Deposit

The ~~current~~Existing FIT does not require a development ~~security~~ deposit. ED proposes that the RAM require a development ~~security~~ deposit of $20/kW.

ED recommends that this deposit is either (a) refunded once the project is operating or (b) applied to the subsequent performance deposit.

9.2.2.1. Party Positions

In response to ED's proposal, parties recommend a range of development ~~security~~ deposits from zero[184][93] to at least $30/kW.[185][94]

~~We adopt a development security deposit, based on ED's recommendation, of $20/kW which is either refundable upon achieving commercial operation (e.g., COD) or applied to the subsequent performance deposit. The deposit is due on the date of contract execution in the form of cash or a letter of credit from a reputable U.S. bank.[186] It is forfeited if the project fails to come on line within 18 months or other extension granted by the IOU.[187]~~

~~We adopt a development security deposit because IOU costs relative to a failed project are not zero (e.g., there are costs to obtain replacement power). The deposit provides collateral against those costs without requiring a complicated, potentially time consuming and costly study of actual damages. A deposit subject to forfeiture also provides a small additional incentive for the developer~~

---

[184][93] See, for example, Sustainable Conservation ~~T&C~~Terms and Conditions Comments at 7; Redwood Renewables ~~T&C~~Terms and Conditions Comments at 5.

[185][94] See, for example, Recurrent Pricing Comments at 7.

~~[186] See SCE T&C Reply Comments at 6.~~

~~[187] It is informative to compare this to the development deposit in the current RPS annual solicitation. Current PG&E annual solicitation protocols require a deposit of $15/kW (between agreement execution and Commission approval), then increased to $100/kW for several products up to the COD. (See PG&E Protocol and D.09-06-018 at 55.) SCE requires a short-list deposit of $3/kW increased to $30/kW (intermittent) and $60/kW (baseload) up to the COD. (See SCE Protocol and D.09-06-018 at C-11.) SCE proposes in its 2010 RPS Procurement Plan that the development security be increased from $30/kW to $60/kW for intermittent resources, and $60/kW to $90/kW for baseload resources.~~

~~to complete the project within the allotted timeframe. The adopted amount, however, is not so large as to cause a serious impediment. Opponents assert~~Recurrent recommends increasing the deposit to at least $30/kW in order to strengthen project and developer viability requirements. Opponents assert that even a small deposit is an unnecessary barrier, but provide no evidence. On the other hand, SCE shows that a $20/kW deposit is less than 1% of an estimated minimal $2,100/kW installed cost for the least expensive renewable project.~~188~~95

Several parties argue that the pay-for-performance feature of paying only for the delivered product provides sufficient incentive for a developer to bring its project to successful commercial operation, and no additional incentive is necessary. ~~We agree that the pay-for-performance structure provides a powerful incentive. It does not, however, completely compensate for the risk, nor eliminate the cost, to the IOU and ratepayer of a project's failure to reach operation. Moreover, a modest additional incentive for timely completion is reasonable.~~ Sustainable Conservation argues there should be no development deposit since it is already a significant challenge to obtain project financing and a project should not have to raise additional capital just to hold a place in the queue.~~189~~96 ~~We disagree. A minimal~~

9.2.2.2. Discussion

We recognize that a development deposit is appropriate because IOU costs relative to a failed project are not zero (e.g., there are costs to obtain replacement power). In addition, because the renewable goals are finite, it is important to take steps to ensure more viable and credible projects are selected as those

~~188~~ ~~T&C~~95 SCE Terms and Conditions Reply Comments at 5.

~~189~~ ~~T&C~~96 Sustainable Conservation Terms and Conditions Comments at 7.

projects that are selected necessarily crowd out other opportunities. To the extent putting capital at risk in the form of a security deposit will screen more speculative projects out of the solicitation; it is to ratepayers' benefit to require such deposits. This needs to be balanced against the risk that if set too high, we will exclude projects that might be reasonably viable but which lack the necessary capital to post a large security amount.

Additionally, because the security deposit is at risk, it will at some level be reflected in the price that developers bid into a given solicitation. The deposit provides collateral against those costs without requiring a complicated, potentially time consuming and costly study of actual damages. A deposit subject to forfeiture also provides a small additional incentive for the developer to complete the project within the allotted timeframe. Further, a reasonable deposit will help filter out projects that investors believe have no chance of success.

~~Recurrent recommends increasing the deposit to at least $30/kW in order to strengthen project and developer viability requirements. We have no evidence of the specific degree to which any deposit, or an increase of $10/kW or more, materially affects viability. We address viability in other, more direct ways (e.g., site control, developer experience).~~

In SCE's RSC program we note that they have implemented a tiered development security deposit that varies based on the size of the project. We believe this approach has merit as it affords a way to balance the benefit of limiting projects to those that are likely to be the most viable with the risk of unnecessarily limiting the field of developers able to participate in the program. As an initial approach for the initial 1000 MW authorization, we believe it is appropriate to look to the precedent established in the context of existing

Commission vetted programs targeting similar resources. In the context of SCE's Solar Photovoltaic Program, we adopted a security deposit of $20/kW. This program targets facilities primarily in the 1-2 MW size range. In the PG&E's Solar PV Program, we adopted a security deposit of $20/kW for projects less than 10 MW and $35/kW for projects 10 MW or greater. In contrast, for annual RPS solicitations, security deposits range from $30/kW to $50/kW for intermittent resources and $60/kW to $100/kW for baseload resources. In addition, in SCE's filing of its 2010 Annual RPS Procurement Plan, it has requested to increase its deposits from $30/kW to $60/kW for intermittent resources and from $60/kW to $90/kW for baseload resources. Furthermore SCE used these higher deposits in its RSC solicitation. Based on this information, we find it reasonable to require a $20/kW development security deposit for projects 5 MW and smaller, and a $60/$90 per kW deposit for intermittent and baseload resources, respectively, for projects greater than 5 MW and up to 20 MW in size. Should Energy Division find that these requirements undermine the goal of promoting a sufficiently competitive market, or that they are not serving their intended purpose, they may adjust these requirements via the resolution process.

9.2.3. ~~10.3.~~ Performance Deposit

The current FIT does not require a deposit to assure performance.[~~190~~97] However, ED proposes no performance assurance/delivery term security

[~~190~~97] A deposit is not required, but performance must be consistent with good utility (or prudent electrical) practices, the project must secure liability insurance, and poor project performance may result in the project owner paying damages to the IOU based on direct, actual losses. See, for example, PG&E § 399.20 PPA at Sections 4.6, 6.0 and 8.0. Also see SCE Renewable and Alternative Power Agreement and SDG&E Renewable Power Agreement at Sections 5.4, 8.0 and 9.0.

deposit (herein called performance deposit) for projects between 1.5 MW and 5 MW.[~~191~~98] ED proposes a performance deposit of 5% of expected total project revenue for projects greater than 5 MW.[~~192~~99] Parties present a range of views from no performance deposit for any project to all projects paying a performance deposit.

We adopt a performance deposit for all projects electing subscription under the RAM. We do this because, as PG&E and others convincingly argue, the deposit is a form of collateral that helps compensate the IOU and ratepayers for damages from performance failure, particularly if the project ceases operation and has few or no remaining assets. [~~193~~100] We also note the desirability of a performance deposit as explained by SCE:

> "SCE's experience, however, is that developers continuously reevaluate the financial performance of their project as their operating and maintenance costs, the energy prices available elsewhere in the market, and their tax incentives change over the life of the contract. Determinations are made whether continued performance under a contract is warranted versus other alternatives that may be available to maximize the developer's return on investment. Developers have in the past and continue today to seek ways to terminate their obligations under existing contracts because they believe a better deal may exist. Performance assurance [deposit] is designed to mitigate the consequences of SCE having to replace the failed project with a similar project."[~~194~~101]

[~~191~~98] In this case, the project's development deposit is refunded, and is not applied to the performance deposit.

[~~192~~99] The $20/kW development deposit is applied to the performance deposit.

[~~193~~100] Those damages might include the cost of replacement power, for example.

[~~194~~101] T&C Reply Comments at 6-7.

For projects less than 5 MW, we adopt a performance deposit equal to the development deposit ($20/kW, or less than 1% of the capital cost of the least expensive project).[~~195~~102] That is, the development deposit converts to a performance deposit.

For projects 5 MW and larger, we adopt a performance deposit of 5% of expected total project revenues. We adopt this deposit for projects 5 MW and larger based on ED's recommendation, also noting that SCE requires a similar performance deposit for projects 5 MW and larger as part of its RSC program. We think SCE has reached the right balance between the burden of a larger performance deposit and project size.[~~196~~103]

We are not persuaded by Sustainable Conservation, IEP and others who assert without evidence that a performance deposit makes it unreasonably difficult to obtain financing. IEP claims, for example, that an obligation of 5% of expected total revenues for a 20-year contract means a performance deposit equal to one year of revenues, which IEP says "can be prohibitively expensive."[~~197~~104] Even if it "can be" for some, we have no evidence that it is prohibitively

---

[~~195~~102] The least expensive project is about $2,000/kW. (See Chapter above on Pricing Approach.)

[~~196~~103] It is informative to compare this to the performance deposit in the current RPS annual solicitation. Current PG&E annual solicitation protocols for any size project require a deposit of 5% of average expected project revenue (expressed as six months revenue for a 10-year contract, nine months revenue for a 15-year contract and one year revenue for a 20-year contract). (See PG&E Protocol June 29, 2009 at 23.) SCE requires a deposit for any size project of 5% of the notional value of the total energy payments expected during the term of the agreement, but not less than $1,000,000. (SCE Procurement Plan, July 17, 2009, Appendix E at 31.) SDG&E requires a delivery term security for any size project of $15/MWh times twice the annual estimated energy amount. (SDG&E Procurement Plan, June 22, 2009, Appendix A at 25.)

[~~197~~104] T&C Comments at 9.

expensive for all. Projects of 5 MW and larger must obtain financing of several million dollars. There is no evidence that the incremental difficulty of obtaining financing to also cover the performance deposit is unreasonable or fatal.[198][105] On the other hand, a relatively small performance deposit will help filter out projects that investors believe have no chance of success, provide incremental incentive (in addition to pay-for-performance pricing) for successful performance, and set aside a modest sum relative to possible damages.

A performance deposit becomes a cost of doing business. It does not give any project a particular advantage or disadvantage because it is uniform for all projects of the same size. A rational bidder will include this cost, along with all other costs, in its bid. A winning bid will, therefore, include this cost, which will in turn be paid by ratepayers. A performance deposit provides some ratepayer security (insurance) against poor performance or project failure, and is a reasonable price for ratepayers to pay over the life of the contract (via winning bid prices) for modest protection.

~~SA~~Solar Alliance and ~~VSI~~Vote Solar propose, without supporting evidence, that the performance deposit be limited to the lesser of six months or 5% of expected contract revenue.[199][106] We believe ED's proposal strikes the

---

[198][105] Assume the investment cost for a five MW project is $3,000/kW, making the investment cost $15 million. If the project capacity factor is 33% and the FIT rate is $0.10/kWh, the total revenue over 20 years for a 20-year contract is $28.9 million. A performance deposit of 5% requires a deposit of $1.45 million. We are not persuaded that financing $16.45 million rather than $15 million is so difficult as to justify a different or no performance deposit. On the other hand, a deposit of $1.45 million reasonably provides additional incentive for good performance and collateral against potential damages caused by project non-performance or failure.

[199][106] T&C Comments at 9.

appropriate balance, and ~~SA~~Solar Alliance and ~~VSI~~Vote Solar do not convincingly demonstrate why it should be modified.

9.2.4. ~~10.4.~~ Performance Obligation

The ~~existing~~Existing FIT requires (a) performance consistent with good utility (or prudent electrical) practices, (b) liability insurance against IOU losses, and (c) project liability for damages based on an IOU's direct, actual losses. ED proposes keeping these requirements and adding an explicit minimum performance threshold. Specifically, ED proposes a performance obligation of 140% of expected annual net energy production based on two years of rolling production, subject to payment of damages for failure to meet the performance obligation.[~~200~~107] In addition, ED proposes that IOUs bear the risk of scheduling deviations if the generator (a) participates in the CAISO Participating Intermittent Resource Program (PIRP), (b) provides the IOU, as scheduling coordinator, with timely information on availability or (c) provides the IOU with remote access to metered output. In conjunction with 10- to 20-year contracts, the performance obligation facilitates IOU long-term renewable resource planning, according to ED.[~~201~~108]

9.2.4.1. Party Comments

Comments range from support to opposition. IOUs generally support ED's proposal. PG&E proposes additional conditions to prevent sellers from underestimating output. For example, PG&E recommends an IOU pay the project the lower of spot price or 75% of contract price for output in excess of 120% of forecast net production. This facilitates IOU scheduling and planning,

---

[~~200~~107] That is, each year the project must deliver about 70% of its forecast annual net energy production.

[~~201~~108] March 2009 Proposal at 11.

according to PG&E, by not letting the seller under-forecast output to avoid the risk of paying damages. PG&E also recommends specificity regarding "timely information" of project schedules to improve an IOU's ability to remarket excess ~~FIT~~RAM electricity.[~~202~~109] SCE proposes use of predetermined capacity factors by technology.[~~203~~110] Sustainable Conservation and other parties oppose ED's proposal on the basis that it is too onerous and makes financing more difficult.

9.2.4.2. Discussion

~~We agree with ED on retention of existing FIT requirements for~~It is appropriate to require performance consistent with good utility (or prudent electrical) practices, liability insurance against IOU losses, and payment of damages based on an IOU's direct, actual losses. ~~We decline to adopt a minimum threshold performance obligation for non-firm, but do so for firm products.~~

~~A specific minimum output requirement subject to a penalty calculation is inconsistent with the variable production nature of an intermittent (non-firm) resource. It also adds unnecessary complexity to contract administration for non-firm resources relative to the existing FIT. For example, if adopted here, parties may legitimately dispute measurements applied to the criteria (e.g., performance, price formulas, capacity factors).~~

~~Pay-for-performance is a powerful incentive for project performance. We rely on the self-interest of the project in maximizing its revenue to reasonably guide performance, particularly in the context of prices differentiated by season and time of delivery.~~

[~~202~~ T&C109 PG&E Terms and Conditions Comments at 11-13.

[~~203~~ T&C110 SCE Terms and Conditions Reply Comments at 7-8.

~~There is also a limited performance deposit as collateral. Failure of the project to perform (e.g., failure to perform consistent with prudent electrical practices) exposes the project to damages based on an IOU's actual losses, including loss of the performance deposit or more. This is also a powerful incentive for performance without a more specifically defined performance obligation.~~

~~We note that non-firm resources have been delivered under the QF program for nearly 30 years. No party presents evidence that this experience supports a minimum performance obligation here, and we are aware of none.~~

~~On balance, we seek a RAM that is relatively simple. This is one area where simplicity can control because the desired performance outcome will be reasonably achieved via other provisions, including pay-for-performance, project self-interest, a performance deposit, a requirement for performance consistent with good utility (or prudent electrical) practices, liability insurance against IOU losses, payment of IOU damages based on direct, actual losses, and generation profiles/characteristics by product to assure the product is delivered consistent with the underlying bid and contract. These same factors will largely also result in the desired performance outcome for firm resources. In addition, however, we adopt ED's recommendation of minimum deliveries of 140% of expected annual net energy production based on two years of rolling production. While simple and minimal, this provides a reasonable additional requirement consistent with the additional commitment expected of a firm resource. We decline without prejudice to adopt the recommendations of PG&E (e.g., lower prices for generation in excess of 120% of forecast) or SCE (use of capacity factors by technology). The proposals fail to contain sufficiently specific language, are not adequately supported by evidence, and are unreasonably complicated. We will~~

~~give further consideration to these or other concepts, however, if proposed with the advice letters to implement RAM.~~ In addition we agree with Energy Division that it is prudent to adopt a minimum performance requirement. To that end, we adopt Energy Division's proposal of 140% of expected two-year production as a simple and straightforward approach. This obligation is identical to SCE's performance obligation in its RPS Pro Forma contract.

9.2.5. ~~10.5.~~ Damages for Failure to Perform

The ~~existing~~Existing FIT limits damages to actual, direct damages, but does not state a maximum dollar amount. In no event under the ~~existing~~Existing FIT is either party liable for consequential, incidental, punitive, exemplary or indirect damages, lost profits or other business interruption damages, regardless of cause.

ED proposes the RAM have a damage limit, wherein damages are capped at a level equal to the contract price minus average market price for the term year, but no greater than $0.05/kWh and no less than $0.02/kWh. In support, ED says a damage calculation is needed to enforce a performance obligation, but should be capped to ensure the contract may be financed and provide certainty to investors.~~204~~111

9.2.5.1. Party Positions

Parties present a range of views. PG&E and SCE support ED's proposal. SDG&E says the $0.05 to $0.02 range is arbitrary and damages should be uncapped. Sustainable Conservation, ~~RR~~Redwood Renewables, and others state that ED's proposed damages are excessive, even if limited, and should be reduced or eliminated. IEP asserts that a project should not be penalized for

~~204~~111 March 2009 Proposal at 11-12.

failure to perform by a minimum $0.02/kWh penalty (e.g., if the market price is lower than the contract price). ~~For the following reasons, we continue existing~~

9.2.5.2. Discussion

We adopt the provisions of the Existing FIT for the RAM standard contract and decline to adopt ED's proposed damage limit.

We have no data to specifically relate the risk and cost to ratepayers of capped damages compared to the benefits, if any, from an increased ability to finance a project or provide certainty to investors. We have no specific data to assess the merits of the recommended range (i.e., $0.05/kWh and $0.02/kWh) versus another range. We also agree with IEP that it is unreasonable to set a minimum penalty even when actual damages are less. In the absence of information justifying a change, we think the best approach is to limit damages to actual amounts as we do now.

~~Therefore, we require continuation of the existing provision that performance be consistent with good utility (or prudent electrical) practices; damages be limited to the actual, direct amount; and neither party is liable for consequential, incidental, punitive, exemplary or indirect damages, lost profits or other business interruption damages regardless of cause.~~

9.2.6. ~~10.6.~~ Force Majeure and Events of Default

PG&E's ~~existing~~Existing FIT defines force majeure, and states that during a force majeure event PG&E (a) need not pay for energy or capacity and (b) may require the seller to curtail, interrupt or reduce deliveries. The ~~existing FITs~~Existing FIT contracts for SCE and SDG&E do not define force majeure and do not contain provisions similar to those of PG&E. All three ~~existing~~Existing FITs contain various terms related to other events of default ~~(e.g.,~~ such as failure

by the seller to take corrective action after notice~~;~~ and seller's abandonment of facility~~)~~ and no party objects to them.

ED proposes that terms for force majeure and events of default be included in the ~~FIT~~RAM contract since these terms protect both buyer and seller from events outside their control.[~~205~~112] Parties generally support ED's proposal, and thus provide limited comments.

We agree with ~~SA~~Solar Alliance and ~~VSI~~Vote Solar that force majeure must be defined, and, to the extent there is liability, provisions must protect both buyer and seller, not just the IOU.[~~206~~113] Terms for force majeure and events of default should be part of RAM. ~~No party objects to other~~Consequently, IOUs should specify force majeure provisions ~~related to events of default (e.g., failure by seller to take corrective action after notice; seller's abandonment of facility). These terms shall continue from the existing FIT into the RAM~~and events of default in their RAM standard contracts.

9.2.7. ~~10.7.~~ Insurance

Insurance provisions in the ~~current FITs~~Existing FIT contracts vary. PG&E's FIT includes a general liability insurance requirement of no less than $1 million for facilities between 0.1 MW and 1.5 MW (with reduced limits for smaller facilities), along with necessary requirements and conditions (~~e.g.~~for example, insurance is primary and not excess to insurance maintained by PG&E). SCE's and SDG&E's Existing FITs require general liability insurance of not less than $2 million for facilities between 0.1 MW and 1.5 MW (with reduced

[~~205~~112] March 2009 Proposal at 12.

[~~206~~ ~~T&C~~113] Solar Alliance and Vote Solar Terms and Conditions Comments at 9.

amounts for smaller facilities), along with necessary requirements and conditions. ED proposes that existing terms continue.

9.2.7.1. Party Positions

Comments on insurance requirements vary. IOUs recommend higher insurance amounts for larger projects. SCE states it is revising insurance requirements under ~~the existing~~its Existing FIT, but provides no specifics. ~~FCE~~FuelCell Energy and others agree with ED that existing insurance requirements are reasonable.[207][114] ~~SA~~Solar Alliance and ~~VSI~~Vote Solar state that insurance requirements should be consistent across the three IOUs, and recommend adoption of the levels used by PG&E.[208][115]

~~We agree with ED and generally continue existing terms. We have no compelling evidence, however, that the potential loss materially differs between IOU service areas. Therefore, in the interest of simplicity and uniformity, we agree with SA and VSI that the insurance limits and terms should be the same among IOUs.~~

~~We agree with IOUs that insurance limits should be relative to the potential loss, but we have no evidence in this record that specifically relates potential loss and project size.[209] Moreover, we have no specific proposals that increase the insurance requirements by project size. On the other hand, SA and VSI state that, even with over 50,000 solar arrays in the United States, they are~~

~~207. T&C~~[114] FuelCell Energy Terms and Conditions Comments at 7.

~~208. T&C~~[115] Solar Alliance and Vote Solar Terms and Conditions Comments at 9.

~~209. For example, we have no specific evidence that the IOU's risk of property damage covered by general liability insurance increases with project size, and whether the relationship, if any, is or is not linear.~~

~~unaware of any documented case of an inverter-based solar energy system causing personal injury or property damage to a utility worker or utility.[210]~~

~~The level used by SCE and SDG&E is relatively modest and not unreasonable. It provides slightly more protection for ratepayers than the level used by PG&E. For the RAM, we adopt the existing $2 million limit used by SCE and SDG&E for facilities greater than 0.1 MW (with reduced amounts for smaller facilities).~~

Environmental Council asserts insurance requirements are overly burdensome, and that there is limited need for insurance because of existing CAISO requirements. It also says the threat of losing queue position and forfeiting deposits limits the need for insurance.[~~211~~116]

9.2.7.2. Discussion

We are not convinced by Environmental Council's claims that insurance requirements are overly burdensome. Environmental Council presents no credible data showing that the level of insurance premium for a $2 million policy is an overly burdensome percentage of either investment or operating cost. Nor does it show that the threat of losing queue position and deposits adequately changes behavior to offset or eliminate the risk of insured loss, or that the level of deposits adequately addresses potential losses covered by general liability insurance. ~~On the other hand, it is clear that insurance~~

Insurance is a reasonable and time-tested method to address risk and potential loss~~.~~ and we expect the IOUs to require insurance in their RAM standard contracts. However, we defer to the IOUs on the amounts and the

---

~~210 T&C Reply Comments at 7.~~

~~211 T&C~~116 Environmental Council Terms and Conditions Reply Comments at 9-10.

terms and conditions of such insurance. As with all of these issues left to the IOUs' discretion and subject to Commission approval through a resolution, we expect them to take reasonable actions to protect their ratepayers while also promoting the competitive energy market. To this end, we encourage the IOUs to develop "tiered" insurance requirements, as appropriate, to address the circumstances of smaller projects or those using different technologies.

9.2.8. ~~10.8.~~ Scheduling Coordinator

PG&E's ~~existing~~Existing FIT requires that PG&E be the seller's scheduling coordinator. ~~(PG&E § 399.20 PPA at 10.1 "Scheduling Obligations.")~~[117] ED proposes that the IOU bear the risk of scheduling deviations if the generator provides the IOU, as scheduling coordinator, with timely information on its availability.[~~212~~118]

We adopt a requirement for the RAM that the IOU be the scheduling coordinator for the project, and the IOU bear the risk of scheduling deviations if the generator provides the IOU, as the scheduling coordinator, with timely information on its availability. The IOU can decline scheduling coordinator responsibilities only upon a written, affirmative request from the seller that the IOU not be the scheduling coordinator, or if unable to perform scheduling coordinator duties (e.g., for a project out of its service area~~, or out-of-state~~). This approach simplifies RAM administration and is reasonable.

~~10.9. Termination, Changes and Ongoing Commission Authority~~

~~Sections 4 and 14 of the existing FIT of SCE and SDG&E contain the following provisions:~~

---

[117] PG&E § 399.20 PPA at 10.1 "Scheduling Obligations."

[~~212~~118] March 2009 Proposal at 11.

~~4.2. [SCE/SDG&E] may elect to terminate this Agreement at 12.:01 A.M. on the 61st day after [SCE/SDG&E] provides written Notice pursuant to Section 10 of this Agreement to the Producer of [SCE's/SDG&E's] intent to terminate this Agreement for one or more of the following reasons:~~

~~(a) A change in applicable Tariffs as approved or directed by the Commission or a change in any local, state or federal law, statute or regulation, any of which materially alters or otherwise materially affects [SCE's/SDG&E's] ability or obligation to perform [SCE's/SDG&E's] duties under this Agreement;~~

~~[(b) through (e) are not applicable and not copied here.]~~

10. Project Viability Requirements

ED proposes that RAM projects meet four minimum project viability criteria before being eligible to submit a bid, including site control, equipment standards, developer experience, and use of a commercialized technology. ED intends the project viability criteria to prevent the authorized capacity under RAM to be filled with non-viable projects to the detriment of projects that can come on line quickly. One of the primary goals of RAM is to support the development of small generation that can interconnect quickly to the distribution system, thereby avoiding the significant time and economic investment required for larger projects requiring transmission upgrades before they can be operational.

Parties present a range of views. Those in support argue the criteria will streamline review and facilitate program success. Those in opposition assert the criteria unreasonably increase project costs and risks.

We agree with ED that some level of minimum project viability criteria must be adopted to support success of the RAM program. We adopt the following minimum viability criteria here:

- Demonstration of site control upon submitting bid
- Demonstration of developer experience;
- Deployment of a commercialized technology;
- Filed interconnection application prior to bid submission;
- Ability for the project to be operational within 18 months of contract approval; and
- Tracking of project milestones.

These criteria should be incorporated in the IOUs' standard RAM contracts. As with all other elements of this program, the utilities may request modifications or additions to the viability criteria via the implementation advice letter process.

10.1. Site Control

ED recommends that the bidder must show 100% site control through (a) direct ownership, (b) lease, or (c) an option to lease or purchase that may be exercised upon award of the contract. We agree.

We want the RAM to be available for projects that are not unduly speculative. To do this, it is reasonable to require site control. Further, we recognize that site control on public lands may be manifested in something other than a lease or sale agreement. Consequently, we decline to adopt specific criteria for what constitutes demonstration of site control and rely upon the IOU to develop its own criteria.

10.2. Development Experience

ED recommends that the bidder demonstrate that the company and/or development team has (a) completed at least one project of similar technology and capacity or (b) begun construction of at least one other similar project. We agree.

Some parties object, saying this criterion is too subjective and exclusionary. They assert that the pay-for-performance nature of the program ensures that only viable projects will participate.[119]

We agree that pay-for-performance is a powerful tool that facilitates viable project self-selection. It is not enough for the RAM program, however. We seek a streamlined process that promotes ease of bid review and selection of projects which can become operational or be removed to open the queue for another project. Development experience complements pay-for-performance in promoting that objective. We require that at least one member of the development team has either begun or complete construction of at least one project similar to the one proposed in the RAM program.

10.3. Commercialized Technology

ED proposes that RAM be limited to commercialized technologies to facilitate the 18-month on-line requirement for RAM generators. ED recommends commercialized technology be defined as one currently in use at a minimum of two operating facilities of similar capacity worldwide.

We agree with a commercialized technology screen. Research, demonstration and development of new technologies are vital, and we encourage such activities. However, research, demonstration and development should be funded in ways other than through the RAM program.

The RPS program itself is largely intended for commercial technologies. California seeks 20% RPS by 2010 with reasonably proven technologies that will provide safe and reliable electricity at just and reasonable rates. Experimental

[119] Pay-for-performance refers to the payment mechanism wherein projects are paid upon delivery of the product (i.e., electricity), with no payment when there is a failure to perform.

technologies may seek a place in the RPS resource mix in other ways and apply via other approaches (e.g., bilateral negotiations).

10.4. Interconnection

We recognize that the interconnection process is integral to the success of RAM. We note that issues regarding jurisdiction of distribution-level interconnections have been raised in FERC Docket No. ER11-1830-000. Commission staff will consider and address these issues in the future as appropriate and necessary, including, without limitation, ensuring non-discriminatory interconnection procedures based on developments in or resolution of the FERC proceeding.

Furthermore, we strongly encourage the IOUs to proactively modify their interconnection protocols for use in RAM where such modifications are reasonable and would enhance the implementation timelines and probability of success of RAM projects. Among other things, the IOUs should consider adopting or modifying criteria for expedited processing where possible, either at the FERC or at this Commission.

Since the interconnection process is a critical milestone to a project becoming operational, Recurrent recommends that bidders demonstrate they have filed their interconnection application by the time they bid into the RAM.[120] We agree.

Given the 18-month deadline for commercial operation, projects must have begun the interconnection application process by the time of bid submission. Thus, such a requirement is a reasonable screening criterion for bids. IOUs

[120] Recurrent Pricing Reply Comments at 10.

should require bidders to show with bid submission that the interconnection application has been filed.

11. Market Elements

11.1. Preferred Locations To Facilitate Interconnections

ED proposes that IOUs make information available on preferred distribution substations based on the available capacity of that substation, updated on a real-time basis.[121] This will significantly assist projects to locate in preferred locations, according to ED, thereby avoiding potential distribution and transmission upgrade costs and delays.

11.1.1. Party Positions

Parties generally agree with the need for and desirability of this data, but present a range of views on feasibility and cost.

SCE proposes providing potential project areas (in the form of a zip code and geographic area bounded by landmarks or specific streets), along with an estimate of approximate available distribution capacity. SCE states that it will update this information as often as possible (including prior to each auction). SCE says this is the same as its solar PV Program auction proposal.[122]

PG&E believes a real time update may require significant investment in communication platforms and resources for system maintenance while not providing significant benefits, particularly if the auction is held only once per year. PG&E recommends a working group to study the issue.[123] SDG&E says it

---

[121] August 2009 Pricing Proposal at 9.

[122] Advice letter 2364-E (process and criteria for evaluating IPP PV offers) resulting from D.09-06-49 (approving SCE's solar photovoltaic program). See SCE Pricing Comments at 7-8.

[123] PG&E Pricing Comments at 12.

is not practical to determine preferred substations and update this list in real-time.[124]

SFUI says IOUs should provide this data on a real time basis, arguing that many cities and water authorities have their water and sewer distribution maps on the internet for immediate access by construction professionals. FIT Coalition states that Ontario Power Authority maintains two reports with needed FIT interconnection data, updated weekly. FIT Coalition recommends the Commission require each IOU to prepare and maintain an interconnection data report following a specified format, updated in real-time. More specifically, FIT Coalition requests the IOUs to provide the total capacity, allocated capacity, queued capacity, and "available capacity" for all distribution substations and each circuit connected to a distribution substation.[125] Recurrent supports ED's proposal with updates as often as auctions occur (not real-time) with information at the zip code level (but not in more detail to avoid a land rush by developers).[126]

11.1.2. Discussion

No party argues that substation data is undesirable, or that it is unnecessary for making informed interconnection decisions. The real issues are the type and amount of data, and frequency of updates.

We recognize that it may be infeasible for an IOU to provide information on all substations during the initial rollout of this program given the large service areas of each IOU. Therefore, an IOU may initially focus on what it determines are "preferred" areas. Preferred areas are likely to be those near load where the

---

[124] SDG&E Pricing Comments at 7.

[125] FITC Pricing Comments at 8-9.

[126] Recurrent Pricing Comments at 9.

IOU has a reasonable expectation of surplus transmission and/or distribution capacity.

The data must be sufficiently detailed to be useful. We agree with parties who assert SCE's proposed "project areas" (zip code and area bounded by landmarks or streets) fails to provide sufficient detail. To be most useful to potential projects, IOUs must provide data at the substation or circuit level. IOUs must have this information in order to execute their responsibilities for daily operations, system scheduling, and infrastructure planning to meet current and future demand. For the initial rollout, we adopt the FIT Coalition's recommendation to require the IOUs to provide the "available capacity" at the substation and circuit level, which we define as the total capacity minus the allocated and queued capacity.[127] The IOUs should provide this information in map format. If unable to initially provide this level of detail, each IOU must provide the data at the most detailed level feasible, and work to increase the precision of the information over time.

We do not require real-time provision of, and updates to, this information. Rather, we require updates at least once a month. We believe this strikes a reasonable balance between providing timely information to the market and not creating a requirement that is overly burdensome. We require that the information be provided as soon as possible, but no later than 60 days after the effective date of this decision. We also expect each IOU to pursue all cost-effective improvements to provide this data at a more detailed level with more timely updates. In order to facilitate data improvements, each IOU should

[127] Allocated capacity refers to generators already connected to that substation or circuit. Queued capacity refers to generators in the interconnection queue at that substation or circuit.

examine DG interconnection screening tools currently used to screen DG interconnection applications. The IOUs should evaluate how individual project studies could be automated to provide the requested data and a reasonable assessment of a DG project's impact on the distribution system. As renewable DG penetrations continue to increase, new software tools and analytics should be evaluated, benchmarked, and used to keep pace with the expected increasing interconnection requests for incremental small DG units throughout the system.

We anticipate that each IOU will, over time, provide system-wide information. To not do so requires IOUs to continuously determine what are and are not "preferred" areas. That involves judgment better left to stakeholders. IOUs should eventually provide reasonable data on all areas, and let developers, along with IOUs and other stakeholders, decide if it makes sense to interconnect at various locations.

We recently adopted similar requirements with respect to SCE, PG&E, and SDG&E PV programs.[128] We therefore expect each IOU to make reasonable initial disclosures, and implement improvements over time. That same approach is reasonable for the RAM. Moreover, we expect the IOUs to simultaneously incorporate data and improvements with respect to their PV programs into the RAM program, and vice versa. Finally, we expect the IOUs to review other utility maps that perform a similar function and to work with parties and Commission staff through the Renewable Distributed Energy Collaborative (Re-DEC) or other forums to order improve the data, usefulness of the maps, and to discuss other issues related to the interconnection of distributed resources.

[128] D.09-06-049 at 40. Resolution E-4299 at 5 - 7. D.10-04-052 at Ordering Paragraphs 9 and 10. D.10-09-016 Ordering Paragraph 4.

11.1.3. Response to Critical Infrastructure Argument

SCE States:

Finally, to the extent the Commission seeks detailed information concerning SCE's substations and distribution system infrastructure, the Commission should keep in mind that such information is protected by the Critical Infrastructure Information Act of 2002, 18 U.S.C § 388.113. Under that statute, detailed information concerning SCE's distribution system, such as precise substation location, substation design, circuit design capacity, voltage, and load information is Critical Energy Infrastructure Information ("CEII") and must be protected. SCE believes that information for distribution system voltage levels of 115 kV and 66 kV may include CEII and cannot therefore be released publicly.[129]

~~14.2 This Agreement shall, at all times, be subject to such changes or modifications by the Commission as it may from time to time direct in the exercise of its jurisdiction.~~

~~14.4. Notwithstanding any other provisions of this Agreement, [SCE/SDG&E] shall have the right to unilaterally file with the Commission an application for change in rates, charges, classification, service, Tariffs or any agreement relating thereto; pursuant to the Commission's rules and regulations.~~

~~FMG objects. FMG asserts that the ability of the IOU to terminate a contract based on change in tariff or federal, state or local law creates unreasonable uncertainty, thereby jeopardizing project financiability. FMG also states that the provision allowing changes or modifications by the Commission creates confusion and discourages project financing.[213] We disagree. These provisions should be included by all three IOUs in the RAM.~~

---

[129] SCE Comments on Proposed Decision, pages 18-20.

~~[213] Pricing Reply Comments at 5-6.~~

~~We have a fundamental responsibility to balance the short-term and long-term needs of all stakeholders, including sellers, buyers and ratepayers. We direct IOUs to buy electricity from RPS facilities under specified terms and conditions, thereby creating a market with assured demand. We secure that direction by, among other things, requiring parties engaging in these transactions to enter into a standard contract.~~

~~The provisions at issue here allow the IOU to terminate the contract only upon a material change affecting the IOU's ability or obligation to perform due to a change in federal, state or local law, or Commission approved or directed change in tariff. Multiple protections are inherent in this process against creation of unreasonable uncertainty or confusion, or the taking of arbitrary or unreasonable actions.~~

~~For example, contract termination can occur only if the change is material.[214] Termination can occur only after a period of 60 days, giving parties a reasonable opportunity to negotiate agreeable modifications. Contract disputes are subject to dispute resolution provisions in the contract (e.g., arbitration, mediation), Commission review, or judicial review.~~

~~A change in federal, state or local law occurs only after a period of public input. A change in law involves a vote by the legislature, affirmation or veto by the Executive Branch, and is subject to judicial review.[215] A Commission approved or ordered change occurs only after notice and opportunity for all parties to be heard. Commission orders are subject to judicial review.~~

~~[214] Termination is not permissible if the change is not material, thereby preventing arbitrary action by the IOU.~~

~~[215] A change in local law may not be subject to the same legislative/executive branch structure, but will involve local authority (such as city councils and mayors), and is subject to judicial review.~~

~~These provisions allow for reasonable treatment of future unknowns (e.g., change in law that responds to a future situation not foreseeable today). They provide due process for sellers, reasonable limits on the IOU's ability to terminate or change, and protection for ratepayers against the most significant of possible adverse events. This is a reasonable approach to handing future unknowns and balancing all stakeholder interests. It is within a framework of due process before legislatures, executive branches, the judiciary, and the Commission. The provisions require notice and a reasonable period before termination (allowing an opportunity for negotiation). They are limited to material events, and dispute resolution procedures may be invoked. This provides a reasonable balance of competing interests. It is within our responsibilities and jurisdiction to require inclusion of these terms in the standard contract.~~

~~Moreover, each RAM tariff and the RAM program is authorized by the Commission. We have ongoing responsibility to ensure that each IOU's tariffs and procurement programs are – and remain – prudent and in the public interest. Ongoing Commission jurisdiction is a reasonable term. Sellers unable or unwilling to accept these provisions may negotiate other treatment in another, non-tariff venue (e.g., bilateral agreements, IOU voluntary programs). Acceptance of the Commission-authorized RAM standard contract, however, should include a seller's agreement to these provisions.~~

~~Regarding an IOU's right to file an application, there can be no dispute that an IOU may apply for changes in a tariff, agreement or program over which the Commission has jurisdiction. Section 14.4 states a right that is not in dispute. Similarly, there is nothing that prohibits a seller from seeking appropriate relief in any venue in which it has standing (e.g., before the Commission or elsewhere).~~

~~This is a reasonable balance of competing interests while protecting ratepayers against adverse outcomes.~~

~~Therefore, RAM for the three IOUs shall contain these terms.~~

The Critical Infrastructure Information Act of 2002 (CII Act) has no bearing on the Commission's decision about whether this information should be provided to potential distributed generation developers. The CII Act distinguishes between submitters and recipients of critical infrastructure information, with the result that the federal statute's prohibition on disclosure of protected confidential infrastructure information applies only when it has been "provided to a State or local government or government agency …" (6 U.S.C. § 133(a)(1)(E),) *See* County of Santa Clara v. Superior Court, 170 Cal. App. 4th 1301, 1319 (Cal. App. 6th Dist. 2009). In this instance, the information in question was generated solely by SCE. Because SCE is neither a state or local government agency, nor a recipient of critical infrastructure information from the federal government, the CII Act and accompanying regulations do not apply.

11.2. Qualified Facility Certification

ED notes that for SCE and SDG&E, the Existing FIT contains a requirement that the project be certified at FERC as a QF. ED proposes that there be no such requirement for the RAM.

We agree. The RPS program is not a QF program. (§ 399.15(e).) RAM is not a QF program. We decline to impose a QF requirement on RAM.

This does not prevent a project from certifying as a QF. A project may certify as a QF if it wants, but it need not do so to be eligible for RAM.

11.3. Conveyance of RECs

The Existing FIT provides that RECs are transferred to the IOU in relationship to the amount of the purchase. For full buy/sell under the Existing

FIT, the IOU buys RECs coincident with the entire generation output. For excess sales, the seller retains RECs for the electricity it uses itself, and the IOU acquires RECs coincident with the excess energy it purchases. (See D.07-07-027 at 33-35.) ED proposes no change relative to the transfer of RECs. We agree.

The same logic used in our Existing FIT decision (D.07-07-027) to justify transfer of RECs coincident with the purchased energy (either total energy production or excess only) applies to the RAM program. Thus, there is no reason to treat the RAM program differently.

We also decline to complicate these transactions by separating the renewable energy credit (REC) from the energy at this time. A guiding principle in RAM is simplicity, and allowing the separation of RECs from energy adds an additional layer of complication. We may consider separating the REC from the energy in the future, but do not do so here.

12. ~~11.~~ Regulation and Commission Oversight

~~11.1. Advice Letter Review~~

~~The existing FIT program does not require that an IOU file a signed FIT contract by advice letter with the Commission. This is because the existing FIT uses a fixed rate stated in the tariff along with a standard contract all predetermined to be just and reasonable up to a maximum program quantity. Our primary need is to keep informed, which we do via periodic reports. (See D.07-07-027 at 7 and 15.)~~

~~For RAM, ED proposes, for projects up to 10 MW, that IOUs need not file an advice letter upon contract execution. ED proposes, for projects from 10 MW to 20 MW, that IOUs file Tier 2 advice letters that become effective in 30 days,~~

~~unless suspended by the Commission.[216] SCE recommends that all contracts executed through the RAM process be submitted by Tier 2 advice letter following each auction.[217]~~

~~The RAM differs from the existing FIT because the rate, even if subject to an SPT, is not preset by the Commission and unambiguously stated in a published tariff. Rather, the RAM rate is determined by the parties pursuant to the specified RAM protocol. Therefore, we agree with SCE and require each signed contract to be filed with the Commission.~~

~~We decline to require a Tier 2 process, which imposes an additional 30-day delay. Rather, the IOU may use Tier 1 for projects with a price up to the applicable SPT. This provides notice to the Commission and the public about the contract (including confidential information for the Commission and those members of the public eligible to receive such information) but does not delay implementation.[218] Tier 1 is reasonable because we have preapproved the price setting mechanism, and the level of Commission review is subject to an SPT. We have preapproved standard contract T&C, and the program is subject to a maximum capacity amount. We decline to adopt ED's approach for separate treatment of projects between 10 MW and 20 MW, and therefore need not consider a separate advice letter requirement.~~

~~We require each IOU to file one advice letter that combines and includes all of its RAM contracts with prices up to the SPT, and to do so within 30 days of~~

~~[216] March 2009 Proposal at 5.~~

~~[217] Pricing Comments at 21.~~

~~[218] While it would be a rare event, a Tier 1 advice letter which raises concerns can be suspended by ED on ED's own initiative, or after a protest. If only one or some contracts raise concerns, ED may suspend Commission approval of just those contracts within the Tier 1 advice letter while the others go into effect.~~

~~the date of the auction. We do this to provide a uniform and efficient structure for program administration, and to facilitate Commission and party review. We direct above that IOUs propose uniform schedules for simultaneously conducting each RAM (e.g., bidders' submission of bids; bid evaluation; notification by IOU to bidders of results; bidder notification to IOUs of intent to proceed; standard contract execution by parties). The final step in that process is for each IOU to batch all of its winning must-take contracts and file one advice letter.~~

~~Contracts that are not must-take (i.e., beyond the capacity cap or at a price higher than the SPT) may be entered into at the discretion of the IOU. The IOU may submit those contracts for Commission review under our other processes (e.g., Tier 3 advice letter or application).~~

~~11.2. **Program Evaluation**~~

~~ED recommends that the RAM be evaluated annually.[219] We agree.~~

12.1. RAM Program Modifications and Reports

As we have said elsewhere in this order, we adopt necessary design elements and details for the initial rollout of the RAM. We expect ED and parties to continually monitor the RAM, and recommend modifications based on evidence, if and as necessary. ~~We caution respondents and parties that a proposed modification must~~ED may act on its own motion to revise any aspect of the RAM program through resolutions proposed for Commission approval. Respondents and parties may seek modification by request to the Executive Director pursuant to Rule 16.6 of the Commission's Rules of Practice and Procedure. Any modifications proposed should be based on ~~factual evidence or~~

~~[219] August 2009 Proposal at 9.~~

~~appropriate legal argument. We will not entertain re-litigation of the decisions herein absent new facts or law~~evidence that the modification is necessary to improve the RAM program.

Regular reports on the RAM program are also necessary and we require each IOU to provide an annual report on the RAM. The IOUs may combine RAM reports with other reports, such as the annual compliance filings required in the IOU Solar PV Programs. In addition, the IOUs will work with ED to determine the content of the RAM report before filing. Among other things, the RAM report shall address the competitiveness of the auctions; auction timing and design issues; and project status, including the time and the cost necessary to interconnect and bring projects on-line.

~~Periodic reports are necessary so that proposed modifications, if any, are based on evidence. To facilitate monitoring, we require each IOU to annually file a report on the RAM with ED. The report should also include an evaluation of relevant conditions, as discussed more below. The first report shall be filed 180 days from the date today's order is issued. The Executive Director may change the date for filing the first and subsequent reports, as necessary and reasonable, for efficient administration. Respondents and parties may seek modification by request to the Executive Director (e.g., Rule 16.6 of the Commission's Rules of Practice and Procedure.) Each IOU shall post each report on its web page. Each IOU shall also post the date for the next report.[220] The information in these~~

~~[220] We would normally require service of reports on the service list. We do not do so here. We expect these reports to continue for many years. The service list will become stale over time. The requirement that the IOU post the report on its website, along with information about report timing, provides a better method of providing timely public access to this information than would a requirement of service on a service list.~~

~~reports shall be reviewed by ED and shall be reflected in the Commission's reports to the legislature on the RPS program. (See D.09-06-049 at 47.)~~

~~11.3. **Data**~~

~~ED recommends the annual evaluation include review of competitiveness, auction design, time necessary to complete projects, auction timing, and project status.[221] We agree.~~

Since the purpose of RAM is the procurement of projects that can come online quickly, in order to ensure that the procurement protocols and program design result in that outcome, we require the IOUs to report on the project development milestones. The IOUs must work with Commission staff to develop a simple methodology to measure the status of project development and include this in their implementation advice letter.

The ~~annual report of each IOU must include information on, and evaluation of, each of these five items. It~~report must also include any other relevant information, data, and analysis to present a complete report to the Commission. IOUs ~~should~~must work with ED ~~and parties~~ to design a report template that includes these elements.

~~Regarding the first item (competitiveness), parties present the complete range of views about whether or not the relevant market is competitive. GPI, for example, asserts the California renewables market is not competitive.[222] IOUs, VSI and others assert the market is competitive.[223]~~

~~[221] August 2009 Proposal at 9.~~

~~[222] "Competition has a particular meaning in terms of economic theory. The problem here is simple. The existing markets for renewable energy in California are not competitive in the economist's sense of the word. Not even close." (Pricing Comments at 4.)~~

~~[223] See, for example, VSI Pricing Reply Comments at 3-4.~~

~~The most fundamental and important requirement for success of the adopted RAM approach is that competition in the relevant RPS market at issue here (up to 20 MW) is fair and vigorous. We adopt a maximum program capacity (1,000 MW) and an SPT (50% above MPR) for streamlined or more intense Commission contract review as mitigation measures against it not being so. We may, however, want to adjust mitigation measures or revise the program if the market is not adequately competitive. Therefore, as ED proposes, it is vital that the data include information on competition and competitiveness.~~

~~This must begin no later than the first report, which we will require 180 days from the date this order is issued. Each IOU should propose one or more candidate definitions of a competitive market,[224] along with its recommendation. Each IOU should propose tools to measure market competition generally, and in this market specifically. Each IOU should also present specific information and data that measure and evaluate the competition in the relevant market here. Each IOU may also state recommendations for improvement, if any.~~

~~As more information and data are available over time, we expect IOU reports to include, at a minimum, the following information and data on competition and competitiveness:~~

- ~~Definition of relevant market~~
- ~~Measures of market competition generally (e.g., homogeneity of product, degree of influence on price, availability of information, ease of movement of resources); and, if different, specifically for the relevant market here~~

~~[224] Four requirements for a perfectly competitive market are: (a) homogenous product; (b) all participants (buyers and sellers) are price takers, and no participant can influence the price; (c) perfect information; (d) unencumbered flow of resources (inputs and outputs). Each IOU's candidate definitions must address these factors.~~

- ~~Measures of market power (e.g., n-firm concentration ratio; Hirschman-Herfindahl Index; Lerner Index)~~
- ~~Seller concentration~~
- ~~Data on each auction (based on all bidders, before projects are selected), such as~~
  - ~~Number of buyers~~
  - ~~Number of sellers~~
  - ~~Prices (maximum, minimum, average)~~
  - ~~Data differentiated by technology~~
- ~~Data on each auction result (after projects are selected), such as~~
  - ~~Number of winning sellers by each buyer~~
  - ~~Prices (maximum, minimum, average)~~
  - ~~Data differentiated by technology~~
- ~~Any other data necessary to present a complete report.~~

~~The first report from each IOU should present information, evaluation and recommendations on the definition of competition and measures of competition, even if actual data is not yet available. Over time, IOUs should present data and evaluation regarding ways to increase the competitiveness in this market, and recommendations for improvements, if any. For example, if improvements are desirable, IOUs should address ways to increase the availability of information, ensure no participant may influence the price, and improve market competitiveness.~~

~~We expect ED to determine the details and format of each report, working with IOUs and parties, to the extent feasible, to ensure that the report details and format are reasonable. ED should post completed IOU reports on the Commission web page, if feasible.~~

~~PG&E is concerned that the annual evaluation of the RAM program may duplicate existing requirements and delay the annual solicitation for other RPS facilities.[225] We expect ED to work with IOUs and parties to ensure that duplication is minimized or eliminated. We encourage IOUs to make proposals as necessary to ensure annual solicitations are not delayed (e.g., file a motion to initiate the next solicitation if a delay otherwise appears imminent).~~

~~PG&E is also concerned that there will be insufficient information in the early years of the program to evaluate results, and suggests the Commission may wish to postpone the first evaluation until 18 months after the first projects are selected.[226] We decline to adopt this recommendation. The first report should contain information on definition and measurement of competition, with preliminary results to the extent feasible. This work is key to further understanding and development of this particular market and the success of the RAM. We expect the data to improve with time, but are confident that IOUs can provide meaningful and informative data (even if preliminary) beginning shortly after program initiation.~~

~~VSI and SA propose that the annual evaluation process be formalized,[227] and CALSEIA recommends an annual public review to identify needed modifications.[228] We decline to adopt these recommendations. We anticipate eventually considering all procurement matters in the LTPP. In the meantime, we now review RPS matters in the periodic review of RPS competitive solicitations. The assigned Commissioner already requires IOUs to report on all~~

~~[225] Pricing Comments at 13.~~

~~[226] Pricing Comments at 13.~~

~~[227] VSI Pricing Comments at 10; SA Pricing Comments at 15.~~

~~[228] Pricing Reply Comments at 4.~~

~~tools used to reach RPS targets and goals, including tariffs/standard contracts pursuant to § 399.20.[229] IOUs should continue to do so, including information on the RAM adopted here. Absent later need for separate evaluation, we expect to consider RAM issues there.~~

~~11.4. Confidentiality of Data~~

12.1.1. Public Release of Aggregated Bid Data

We have rules regarding confidentiality of electric procurement data. (See D.06-06-~~006,~~006 as modified by D.07-05-~~032; the Confidentiality Decision.~~032.) Those rules presume "that information should be publicly disclosed and that any party seeking confidentiality bears a strong burden of proof." (*Id*. at 2.) Due to strong public interest in RPS, we require greater public access to RPS data than other data. (*Id*. at 3.) We reaffirm the importance of greater public access to RPS data here ~~consistent with the Confidentiality Decision~~. We emphasize, for the reasons explained below, that this is particularly true for the RAM program.

ED proposes that it release RAM data on an aggregated basis to the extent consistent with our rules. ED says individual bid prices will remain confidential.[~~230~~130]

Parties present a range of views. ~~FITC~~FIT Coalition argues that winning prices for each project must be revealed or the key aspect of RAM identified by ED (i.e., that RAM provides a long-term investment signal) will not be fulfilled.[~~231~~131] ~~VSI~~Vote Solar, TURN and others recommend maximum disclosure

---

~~229. For example see November 2, 2009 Amended Scoping Memo and Ruling of Assigned Commissioner Regarding 2010 RPS Procurement Plans, Attachment A at 3.~~

[~~230~~130] August 2009 Proposal at 10.

[~~231~~131] Pricing Comments at 5.

of pricing bids.[232][132] Absent complete transparency, SASolar Alliance proposes an after-the-fact review by a designated PRG.[233][133] PG&E points out that limited aggregate information (i.e., number of projects, megawatts per resource type) may be disclosed, but information on offers received in a solicitation may not be made public for three years.[234][134]

Information is vital to an effectively functioning competitive market. We expect IOUs and ED to make the maximum amount of information public. In fact, all data must be public unless a party carries a strong burden of proof otherwise, consistent with the Confidentiality Decision. It is particularly important for the RAM due to our reliance on the underlying market being competitive.

It is also important that the maximum amount of price information be available in order to gain public acceptance of the RAM. The majority of parties recommending a fixed price FIT, for example, do so because they assert it is open, transparent and objective, while RAM, absent adequate price and other information, is closed, opaque and subjective. The goal of RAM may be lower prices (compared to a fixed price FIT), but without price data, and market information on the degree of competition, the public must take on faith any statement (including those made by an IOU or the Commission) that costs have been reduced or competition achieved. RAM program credibility requires that IOU and Commission administration provide full opportunity for the public to assess the merits of the RAM and reach its own conclusions. Therefore, the

---

[232][132] VSIVote Solar Pricing Comments at 10; TURN Pricing Reply Comments at 9.

[233][133] Pricing Comments at 18.

[234][134] Pricing Comments at 13-14.

~~maximum price and other information must be revealed, consistent with the Confidentiality Decision.~~

We expect ED, respondents, and parties to explore all reasonable means to make price and other information widely available. ~~This may involve, for example, releasing aggregated data. It may also involve release of specific data (e.g., maximum, minimum, average, individual prices) without reference to the seller. SA recommends certain tasks be performed by a PRG. In particular, SA recommends the PRG examine auction results to assure price and viability criteria were properly applied. We agree. The PRG is to review RPS procurement. That should include RAM.~~ At a minimum, we require specific information to be revealed publicly. For all bids received and shortlisted, we require the IOUs to provide the following information: names of participating companies and the number of bids per company; number of bids received and shortlisted; project size, participating technologies, quantitative summary of how many projects passed each project viability screen, and location of bids by county provided in a map format. Finally, the IOUs must release information on the achievement of project development milestones for all executed RAM contracts. Pursuant to the program goal to select projects that can come online quickly, we believe this information is essential to verify that the program protocols and design are achieving the intended outcome. This transparency will allow the Commission to make changes to the program in order to increase its efficiency and effectiveness.

12.2. ~~11.5.~~ Cost Recovery

AReM proposes that costs related to the ~~expanded FIT~~RAM should be borne by bundled service customers, and not customers of ESPs or CCAs. IOUs,

TURN and others believe all customers should bear the costs of ~~an expanded FIT~~the RAM, including customers of ESPs and CCAs.

We currently permit an IOU to recover costs incurred in meeting its RPS obligations (including ~~existing~~Existing FIT costs) from its bundled customers. These are typically part of generation or procurement costs recovered via each utility's annual Energy Resource Recovery Account proceeding. We also permit recovery of appropriate non-bypassable costs (including stranded costs associated with RPS resources) from certain customers that depart from the utility bundle after those new resources are procured.[~~235~~135] We are not persuaded to make any change for the RAM. We recently reached the same conclusion regarding a similar program,[~~236~~136] and know of no reason to reach a different result here.

~~11.6. Price in Excess of MPR After Above Market Funds are Exhausted~~

~~SCE asserts that an IOU's obligation to procure an RPS contract at a cost above MPR is limited. SCE says that each IOU has a statutory limit on the total costs it must spend above market prices for procurement of renewable energy to reach RPS targets, citing § 399.15(d) in support. According to SCE, the Commission is obligated to apply above MPR costs toward the above market fund cost limitation, and IOUs are required to procure renewable energy at a cost above MPR only until the cost limitation is reached. SCE concludes that RAM~~

[~~235~~135] Those are departing direct access customers, CCA customers, new Western Area Power Administration and split wheeling departing load customers, and departing load associated with a large municipalization. (D.08-09-012, Ordering Paragraphs 1 and 3.)

[~~236~~136] D.10-04-052 at 69.

must not require an IOU to procure renewable energy at a cost above MPR in those cases.[237]

We disagree. VSI, for example, convincingly argues otherwise.[238] The above market cost cap cited by SCE is applicable only if five conditions are met. The first condition is that the contract must be selected through the competitive solicitation process established in § 399.14(d). That process is the annual bid solicitation pursuant to each IOU's renewable energy procurement plan. We have authorized several such plans. (See, for example, D.05-07-039, D.06-05-039, D.07-02-011, D.08-02-008, D.09-06-018.) The selected contract must be accepted by the Commission based on consistency with the approved plan. As VSI correctly notes, this excludes renewable electricity procured in several other ways, such as bilateral contacts, SGIP, CSI, and the existing FIT (§ 399.20). It also excludes contracts pursuant to RAM.

12. **Counting Excess Sales Toward Program Capacity Limit**

PG&E, SCE and SDG&E must offer existing FIT customers the choice of selling electricity under an arrangement of either (a) full buy/sell or (b) excess sales.[239] (See D.07-07-027 at 33-38.[240]) PG&E and SCE ask for further consideration of how electricity sold under excess sales is measured toward the program maximum capacity (originally 250 MW). We use the seller's entire

[237] Pricing Comments at 12-13.

[238] Pricing Reply Comments at 6-7.

[239] Under full buy/sell, the customer sells its entire output to the utility, and buys back the electricity it needs to meet its load. Under excess sales, the customer sells only the electricity that is excess to its own needs.

[240] The other four utilities (PacifiCorp, Sierra, Mountain Utilities, Bear Valley) must offer to purchase pursuant to full buy/sell, and may offer to purchase via excess sales.

~~rated generating capacity (also called installed or nameplate capacity) for the reasons explained below.~~

~~FIT program maximum capacity (250 MW under AB 1969; 750 MW under SB 32) is measured in megawatts, not megawatt-hours. That is, the law provides that capacity is measured as "rated generating capacity."[241] PG&E correctly says: "[b]ecause the statute speaks of limits in terms of capacity, not energy, the progress toward program limits should be measured in MW, not MWh."[242]~~

~~No party disputes that for full buy/sell the IOU uses the entire rated generating capacity of the facility, measured in megawatts. SCE reports that this is the installed capacity. PG&E refers to this as nameplate capacity. The standard contract of each IOU requires the project to state its total generating capacity.~~

~~There are two recommendations for treatment of excess sales. The first is to use the entire rated (installed, nameplate) capacity, just as with full buy/sell. The second is to subtract the customer's load from the full rated capacity and use only net capacity.~~

~~We are persuaded by SCE and others to use the first approach (entire rated capacity). The seller knows the capacity of the plant, the contract can require that the seller provide this information to the buyer, and the buyer can reasonably confirm the capacity. Use of entire rated capacity is direct and simple. It is less likely to result in disputes and uncertainties about project amounts, and whether and when the program capacity limit has been reached.~~

~~[241] This was originally § 399.20(c), and pursuant to SB 32 is now § 399.20(f).~~

~~[242] Initial FIT Comments at 11.~~

~~IEP, VSI, Recurrent and GPI argue that only the excess sales portion of a customer's production should count against the program limit. To do so, excess capacity must be measured. IEP recommends:~~

> ~~"…the difference between the nameplate capacity of the customer's generating facility and customer's historical peak demand could provide a basis for the calculation of excess capacity."[243]~~

~~VSI and Recurrent recommend the historical peak demand be measured over the last year.~~

~~We decline to adopt a method that requires determination of excess capacity. There are multiple ways to measure demand.[244] Needless decisions would be required, measurements taken, and disputes likely.~~

~~Moreover, a method selected for existing customers does not address new customers (who have no historic demand). To address new customers, VSI and Recurrent recommend that for "new load, peak demand will need to be based on a reasonable estimate."[245] We decline to adopt an approach that relies on an estimate, which may or may not be accurate and may require a subsequent true-up adjustment.~~

~~An alternative is to convert energy to capacity via a formula. We are not persuaded that we need to engage in conversion. We have no such formula, and decline to create one. Once created, it would require data, and would open the~~

~~[243] Initial FIT Comments at 10.~~

~~[244] The customer's peak demand may be measured over any period (e.g., one minute, 15 minutes, 30 minutes, 1 hour). The historical demand may be calculated over many different periods (e.g., the single highest demand in a selected day, week, month or year; or it may be averaged over those periods).~~

~~[245] Initial FIT Comments at 16.~~

~~opportunity for disputes. Rather, we opt for a more direct and simple approach to reasonably implement this provision of the law.~~

~~Several parties argue in favor of using excess capacity because applying total capacity toward the total program limit (rather than applying only the amount in excess of load) will exhaust the program limit more quickly. While this concern is valid, we also note that the program limit may be increased, if and when appropriate. We balance measuring and administering a net capacity metric against modifying the maximum capacity cap, and conclude the latter is a preferable remedy, if needed. We encourage IOUs, parties and staff to bring concerns about program exhaustion to our attention when appropriate so remedies, if any, can be considered. In the meantime, we opt for simplicity absent a convincing need for complexity.~~

~~13. Third Party Ownership~~

~~Consistent with statute at the time, our initial implementation of the FIT required that eligible electric generation facilities be owned and operated by the retail customer of the electrical corporation, and be located on property owned or under the control of the retail customer.[246] (§ 399.20(b) before amendment by SB 32.) We were also interested in the possibility of other ownership options, including partial or full ownership by electrical corporations or others. (See, for example, D.08-02-008 at 32-35.) Our interest was in exploring all reasonable opportunities for renewable resource development while promoting reasonable competition and efficiency. Parties were asked to comment.~~

~~[246] We expanded the program from water and wastewater to other customers, and specified the expansion to generally be on the same terms. Several parties noted that this did not necessarily require the customer to also be the owner and operator of the facility. PG&E, for example, required the seller to be a customer, but did not require the seller to own and operate the facility.~~

~~PG&E commented that "[t]hird party ownership and financing should increase the number of potential sellers and therefore increase the amount of renewable generation in the state."[247] We continue to be interested in removing barriers that unnecessarily hinder consideration and development of reasonable projects. We think that increased opportunities for ownership and financing are generally positive.~~

~~On the other hand, several parties pointed out that partial or full third-party ownership would require an amendment to the law because, at the time parties filed comments on this matter, § 399.20 required that the project be owned and operated by the retail customer and be located on property owned or under the control of the retail customer. The law has now been amended. (SB 32.)~~

~~As amended, there is no longer a requirement that the seller be a retail customer of the electrical corporation, nor that the project be located on property owned or under the control of the retail customer. (§ 399.20(b) as amended by SB 32.) We know of no reason why RAM should be different from the current version of the underlying FIT program. This change should increase the number of potential sellers, the amount of competition, and the amount of renewable generation. Therefore, consistent with § 399.20(b), as amended by SB 32, RAM tariffs/standard contracts filed pursuant to this order shall not require that the seller be a retail customer, nor that the facility be located on property owned or under the control of the retail customer.~~

~~PG&E points out a potential adverse effect of third party ownership: program manipulation.[248] For instance, PG&E says the ownership structure can~~

~~[247] Initial FIT Comments at 12.~~

~~[248] Initial FIT Comments at 12.~~

~~be easily dissolved and reconstituted as a different entity if the facility is a limited liability company. Potential sellers may use this ownership structure to terminate an existing contract and execute a new one at a higher price. PG&E states this risk is manageable now, but suggests reconsideration if this adverse effect begins to occur.~~

~~This risk, albeit now manageable, exists throughout the RPS program. It is not limited to small projects (procured via annual bid solicitation or any other procurement mechanism), and is not limited to RAM. Similarly, the cure is not limited to small projects or RAM.~~

~~The cure used in the current RPS program is generally via deposit and damage provisions for failure to fulfill the contract. Damages may include forfeiture of development or performance deposits, and liability for actual damages. We agree with PG&E that the risk is manageable now, and has generally been reasonably addressed via deposit and damage provisions, and other T&C of the contract. We encourage IOUs, staff and parties to make proposals (supported by facts and arguments) to change deposit and damage provisions, change other provisions, or add new provisions, if necessary, should an IOU or party find this element of the program needs improvement.~~

~~14. **Other**~~

~~Parties were asked to identify anything else the Commission should consider before completing implementation of an expanded FIT. Parties present limited additional issues, which we have either addressed above or need not address now for purposes of initial implementation of RAM.~~

~~For example, SCE urges the Commission to assist and encourage IOUs in their development of voluntary programs, such as SCE's Standard Biomass~~

~~Program (now SCE's RSC program).[249] We have done so. We cited D.09-06-018 earlier in this order (pointing out our recognition of SCE's initiative and innovation with voluntary programs, and encouragement of other IOUs adopting a similar approach). We have considered but rejected related proposals above (e.g., counting capacity acquired under voluntary programs toward the 1,000 MW RAM program cap). SDG&E proposes that above market costs of RAM be shared by all customers.[250] We have addressed that above.~~

~~We have resolved all issues necessary for the initial rollout of RAM. Parties may subsequently raise issues that merit further consideration as we continue to examine and implement RAM.~~

13. ~~15.~~ RAM Program Implementation

~~15.1. RAM Tariff~~

~~We expect PG&E, SCE and SDG&E to work diligently with the other IOUs, ED staff and parties to develop, to the fullest extent feasible, one common RAM tariff . The tariff shall include (or attach) a standard contract and all other documents necessary to establish RAM bidding protocols in order to efficiently and effectively administer RAM. These are the implementation and administrative details needed to execute RAM. This may include, for example, RAM solicitation materials that will be provided to potential bidders; statement of solicitation amounts of firm, non-firm peaking and non-firm non-peaking for each of the four auctions; process for bidders to submit bids; bid forms and protocols; timeline; definitions (if necessary and appropriate) of terms for project viability criteria; criteria to ensure bids are submitted on a comparable basis; generation profiles or other characteristics that correspond to the product; and~~

~~[249] Initial FIT Comments at 11.~~

~~[250] Initial FIT Comments at 13.~~

~~any other detail needed for successful program execution. The tariff shall incorporate the orders herein, and, to the fullest extent reasonable, shall use the same form, format and language.[251]~~

13.1. RAM Implementation Advice Letter Filing

PG&E, SCE, and SDG&E shall file Tier ~~2~~3 advice letters within ~~21~~60 days of the date this order is mailed~~. Each IOU's advice letter shall explain differences between the tariffs, if any, and state reasons in support.~~ to put RAM procedures in place. The implementation advice letters shall include procurement protocols, a RAM standard contract consistent with the provisions of this decision, and any other details necessary to implement the program. Furthermore, the IOUs should use the advice letters filed pursuant to the decisions establishing the IOU Solar Photovoltaic Programs[137] as a model on what to include in the RAM advice letter.

Other requirements of the advice letter filing including the following: the IOUs shall state when they will hold a RAM auction and specify the amount of capacity and the products they will plan to procure in each auction over the next two years. IOUs shall include and explain any other bid selection criteria they will utilize, for example a seller concentration limit. The advice letter filing shall include a description of the generation profiles and characteristics that correspond with each product bucket. Furthermore, the IOUs shall provide the preferred locations map and a description of how the maps were computed. The IOUs may include any other requests related to the implementation of RAM

~~[251] The issue of economic curtailment has been raised in this proceeding in relationship to the 2010 Procurement Plans. It is not addressed in this order. IOUs should not, until the Commission addresses the resolves the issue, include economic curtailment provisions in the RAM tariff.~~

[137] See D.09-06-049, D.10-04-052, and D.10-09-016.

auctions, which are consistent with this decision, for Commission consideration. Parties may file and serve comments or protests within 20 days of the date the IOUs' implementation advice ~~letter is~~letters are filed. (General Order 96-B~~, § 7.4.) Unless suspended by the Energy Division Director, the advice letter shall become effective 30 days from the date the advice letter is filed.~~)

~~The first auction pursuant to the RAM will be held within 90 days of the date the last of the three RAM tariffs/standard contracts/bid protocols is effective, and will be held simultaneously by the three IOUs. Subsequent RAM auctions will be held no later than every 180 days thereafter, and will be held simultaneously by the three IOUs. The timing of each auction shall be supervised by the Commission. The Executive Director may, for good cause, change these timeframes upon notice to the IOUs and service list, but shall do everything reasonably possible to ensure that two auctions are held per year. IOUs shall request extensions consistent with procedures in the Commission's Rules of Practice and Procedure. (Rule 16.6.)~~

Lastly, in the interest of ensuring that this program remains relevant and effective we believe that periodic program forums are appropriate and should be held once per year, beginning after the initial RAM auctions are conducted. These forums will provide a venue to discuss program design and implementation, and provide opportunities for stakeholder comments and feedback. Such forums can provide invaluable insights into the effectiveness of the program as adopted and suggest potential modifications that may be appropriate to ensure the program is realizing its intended aims. The IOUs may use the stakeholder feedback from each forum to develop and submit advice letters seeking modifications to the RAM program. Similarly, Energy Division may issue a resolution on its own motion to propose program modifications

based on information from these program forums, as well as information from the program reports described above.

13.1.1. ~~15.2.~~ The Existing ~~Tariff~~FIT

The Existing FIT—the statutory MPR-based fixed price tariff for 250 MW of water/wastewater retail customers—applies to projects independently of the RAM.[252] We will ~~soon~~ update the ~~existing~~Existing FIT in a separate decision to address final implementation issues scoped in June 2008, along with provisions of SB 32. This will include, for example, treatment of excess sales to program capacity limits, third party ownership, an updated price, an updated MW allocation (from 250 MW for water/wastewater customers of electrical corporations to 750 MW for all customers of electrical corporations and local publicly owned electric utilities), and other items as appropriate.

14. ~~16.~~ Comments on Proposed Decision

On August 24, 2010, the proposed decision of Administrative Law Judge (ALJ) Burton W. Mattson in this matter was mailed to parties in accordance with Section 311 of the Public Utilities Code and Rule 14.3 of the Commission's Rules of Practice and Procedure (Rules). On ~~_____, comments were filed by _____. On _____~~,September 27, 2010, comments were filed by Axio, CalSEIA, CARE, CEERT, DRA, enXco, FIT Coalition, Fuel Cell Energy, GPI, IEP, Jan Reid, LS Power Associates, PG&E, Recurrent Energy, SCE, SDG&E, SFUI, Sierra Club, Solar Alliance, Sustainable Conservation, TURN, and Vote Solar. On October 4, 2010, reply comments were filed on by ~~_____.~~ CARE, DRA, FCE, FIT, GPI, Jan Reid, LS Power Associates, PG&E, SCE, SDG&E, SFUI, Solar Alliance, Sustainable Conservation, TURN, Vote Solar, Walmart, and Western

~~[252] § 399.20, implemented and expanded to other customers by D.07-07-027, D.08-02-010 and D.08-09-033.~~

Power Trading Group. The proposed decision was significantly modified to address the comments. Among other things: the value of RAM as a program to target viable renewable distributed generation that can interconnect quickly was clarified; the simplified preapproval threshold was eliminated; our intent to explore a more nuanced need for RAM by coordinating with the CPUC's procurement planning process was clarified; the discretion to reject bids that are not cost competitive or resulted in market manipulation was given to the IOUs; the requirements of some of contract terms and conditions were left to the discretion of the IOUs; the development deposit requirement was increased; the termination contract requirement was removed; the project size limit was changed to 20 MW; only the excess sales from a generator will count toward the 1,000 MW capacity limit; RAM documents need not be uniform across IOUs; the IOUs must provide more relevant preferred location information to bidders; the eligible location for RAM projects was limited to the IOU service territories; annual RAM reports shall be filed and the content determined in collaboration with Energy Division and IOUs; and a process is provided for timely modifications to the RAM program.

15. ~~17.~~ 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. It is feasible and desirable to ~~streamline the~~design a streamlined procurement process for smaller renewable energy projects ~~by expanding the existing FIT~~.

2. ~~The CEC has repeatedly recommended that we study and implement a FIT for projects up to 20 MW, and a project size of 20 MW is used for many program~~

and regulatory purposes. Smaller renewable energy projects may be able to be developed more quickly and with greater certainty than larger scale renewable projects given their smaller geographic and environmental footprint, and the ability to interconnect without requiring additional transmission or distribution system upgrades.

3. The existing FIT applies the per project (transaction) limit in relationship to the amount the IOU is buying, not the size of the seller's facility.

4. Interconnection procedures exist for all projects (from less than 1 MW to several hundred MW), these procedures require system stability and cost studies, and interconnection requirements do not differ depending upon how the price is determined.

5. Balancing of risks among all stakeholders in the RPS program is a consideration at all project sizes, and is best addressed by contract terms and conditions rather than a per project size limitation.

6. The RPS and QF programs overlap, and are closely related, but are separate programs.

3. **7.** RAM is a market-based pricing mechanism wherein the price is set by the seller and buyer participating in a competitive solicitation, not the Commission.

4. A fundamental assumption underlying the adopted RAM is that competition is, and will remain, vigorous in this market, resulting in just and reasonable rates and optimal resource outcomes.

5. **8.** The QF market for projects 20 MW and less is not sufficiently competitive to let the market by itself reach a just and reasonable result, while

~~the RPS market~~RPS statute and program is premised upon employing competition to reach optimal outcomes.

~~**9.** An RAM-determined rate provides reasonable price certainty for the purposes of project economic evaluation and subsequent cash-flow for cost recovery.~~

~~**10.** Projects at issue here, even if relatively small, are costly, with an investment cost that can be more than $1 million.~~

6. ~~**11.**~~ The time and cost of an administrative process to set a fixed rate for a FIT tariff is not zero, and could be the same as or more than the sum of all RAM bid preparation costs.

7. A RAM-determined contract price provides reasonable price certainty for the purposes of project economic evaluation and subsequent cash-flow for cost recovery.

8. A RAM balances the ability for a small project to secure financing and attain a reasonable price, with the assurance that the ratepayer is not overpaying.

9. The Existing FIT is a must-take obligation on a first-come first-served basis up to a program capacity limit.

10. Because IOUs are given discretion to reject bids that are uncompetitive, the issue of whether RAM is a must-take obligation is moot.

11. SCE has implemented its RSC program, has conducted one solicitation in 2010, and has already executed 21 contracts pursuant to this solicitation.

12. ~~Compared to a revenue requirement cap, a total capacity cap of 1,000 MW is relatively simple while being sufficiently large to test the adopted program expansion but sufficiently small to provide protection against adverse outcomes.~~Establishing one primary procurement vehicle for the system-side DG market can enhance competition and put downward pressure on bid prices.

~~**13.** A limited must-take obligation provides reasonable certainty for and balance between (a) the market (regarding regulatory approach), (b) ratepayers (regarding cost and resource portfolio), and (c) IOUs (regarding cost recovery); while reasonably implementing Commission authority to establish IOU procurement practices, including resource-specific targets.~~

~~**14.** Requiring deliveries on the basis of RPS eligibility standards as determined by CEC matches the same provision in the annual bid solicitation portion of the RPS program, will not cause confusion, will increase competition, and will include areas with some of the best renewable potential.~~

~~**15.** CCAs and ESPs will have a competitive advantage over IOUs if CCAs and ESPs are given the right of first refusal for electricity from an RPS project in the service area of the CCA or ESP.~~

13. ~~**16.**~~ A proportional allocation of the 1,000 MW cap to the largest of the four SMJUs would be about 4 MW, and to all four of the SMJUs would be about 6 MW.

14. ~~**17.**~~ Relative to a 20 MW per project (transaction) criterion, allocating 4 MW or less to each of the four SMJUs makes little practical sense while increasing administrative burden.

15. Calculating a revenue requirement cap will require coordination with the CPUC's procurement planning processes.

16. Before a revenue requirement cap is calculated, a total capacity cap of 1,000 MW is a relatively simple approach that is sufficiently large to test the adopted program but sufficiently small to provide protection against adverse outcomes.

17. If an IOU would like to procure beyond its initial allocation of the 1,000 MW cap, it is reasonable for an IOU to request an increase in its implementation advice letter.

18. ~~A requirement that a project meet limited minimum project viability criteria to submit a bid provides an initial screen of more viable from less viable projects; simplifies bid review and selection; provides a modest incentive for bidders to submit realistic, competitive bids; complements the provision of limited time to commercial operation; assists with reasonable queue management; and should reduce the number of extension requests.~~ It is reasonable to authorize the Director of Energy Division to explore methodologies for aligning RAM procurement authority with the Commission's procurement planning process to assess the need for RAM products going forward.

19. ~~Ranking an auction result only by price without any product differentiation will skew selection to the lowest cost projects without acceptable product diversity.~~ It is reasonable for the Director of Energy Division to have the authority to adjust the capacity cap on its own motion or in response to a utility advice letter filing requesting an update to the cap amount.

20. ~~There are too many technologies to reasonably differentiate products by technology in the RAM.~~ If IOUs hold two RAM auctions per year, it will provide market participants with regular opportunities to participate.

21. Multiple RAM auctions will not be unreasonably burdensome or costly if IOUs design a standard contract and bid protocol that meet the goals of being simple, easy to implement, and streamlined.

22. ~~21.~~ Project selection limited to the price variable is consistent with the RAM being relatively simple and transparent.

~~**22.** An SPT helps protect ratepayers from potentially imprudent IOU procurement by focusing Commission and public attention on certain contracts.~~

23. ~~An all-in energy rate paid by TOD is reasonably simple, pays for performance, provides a reasonable incentive for sellers to provide electricity by TOD, and moderates ratepayer risk (since payment is made only for delivered electricity).~~ Ranking an auction result only by price is reasonable when the auction is targeting products with similar value.

24. ~~Multiple RAM auctions will not be unreasonably burdensome or costly if IOUs design a RAM tariff,~~ ~~standard contract and bid protocol that meet the goals of being simple, easy to implement, and streamlined.~~ Renewable products that are baseload, peaking as-available and non-peaking as-available provide different value to an IOU's electric portfolio.

25. It is reasonable for an IOU to have the discretion to reject bids if they are not cost competitive or if there is evidence of market manipulation.

26. A Tier 2 advice letter gives notice to the Commission and the public regarding an RAM contract without causing implementation delay.

27. Not requiring the seller to be a retail customer, and not requiring the project be located on property owned or under the control of the retail customer, provides a reasonable opportunity to increase the number of potential sellers, the amount of competition, and the amount of renewable generation.

28. ~~**25.**~~ Having both the full buy/sell and excess sales options available at the choice of the seller has been, and continues to be~~,~~ workable, with no evidence showing the contrary.

~~**26.** The possible benefits of a seller concentration test do not outweigh the potential complexities and disputes that could accompany its implementation.~~

~~**27.** Data on the feasibility of interconnection must be sufficiently detailed and current to be useful to potential project developers.~~

29. The CEC has repeatedly recommended that we study and implement an FIT for projects up to 20 MW, and a project size of 20 MW is used for many program and regulatory purposes.

30. Small RPS projects connecting to utility service territories incur none of the additional costs associated with some other forms of renewable generation.

31. Adopting standard non-negotiable RAM contracts is consistent with the goals of the RAM program, including simplicity and reduced transaction costs.

32. ~~**28.**~~ An 18-month limit for a project to begin commercial operation (with ~~limited~~one potential ~~extensions in~~ six-month ~~increments~~extension) reasonably streamlines RAM administration~~, and makes scarce T&D resources available when otherwise tied up in delayed projects~~, while accommodating legitimate delays.

33. ~~**29.**~~ A development deposit is a form of collateral that helps compensate the IOU and ratepayers for damages from a project that fails to reach commercial operation.

34. ~~**30.**~~ A development deposit of $20/kW ~~is less than 1% of the estimated installed cost for the least expensive renewable project~~for projects 5 MW and smaller, and a $60/$90 per kW for intermittent and baseload resources, respectively, for projects greater than 5 MW and up to 20 MW in size is consistent with IOU requirements in other programs for similar resources.

35. ~~31.~~ A performance deposit is a form of collateral that helps compensate the IOU and ratepayers for damages from project performance failure.

36. ~~32.~~ A performance deposit is a cost of doing business, and a rational RAM bidder will include this cost with all other project costs in bid development.

~~33. A specific minimum output requirement subject to a penalty provision for an as-available product is inconsistent with the variable production nature of an as-available (non-firm) resource, adds unnecessary complexity to contract administration relative to the existing FIT, and is not necessary to motivate minimum production given that pay-for-performance is a powerful incentive for reasonable project performance.~~

~~34. A specific minimum output requirement subject to a penalty provision for a firm product is consistent with the additional commitment expected of a firm resource.~~

37. It is appropriate to require performance consistent with good utility practices, and it is prudent to adopt a minimum performance requirement.

38. ~~35.~~ The risk and cost to ratepayers of capping damages at 5 cents/kWh compared to the benefit from an increased ability to finance contacts, if any, is unknown, while a minimum penalty of 2 cents/kWh penalizes projects if actual damages are less.

~~36. Insurance limits and terms should be the same among the three IOUs to promote simplicity, uniformity, and ease of administration.~~

~~37. The existing insurance requirements used by SCE and SDG&E are reasonable.~~

39. ~~38.~~ A requirement that the IOU be the project's scheduling coordinator (unless this service is specifically declined by the project, or the IOU is unable to perform this service) simplifies RAM administration.

~~39. Provisions in the existing FIT of SCE and SDG&E regarding an IOU's termination right and Commission jurisdiction (§§ 4.2, 14.2 and 14.4) reasonably limit an IOU's ability to terminate or change the contract, and provide both buyer and seller protection against the most significant of possible adverse events.~~

40. A ~~Tier 1 advice letter gives notice to the Commission and the public regarding a RAM contract without causing implementation delay.~~ requirement that a project meet certain minimum project viability criteria to submit a bid provides an initial screen of more viable from less viable projects; simplifies bid review and selection; provides an incentive for bidders to submit realistic, competitive bids; complements the provision of limited time to commercial operation; assists with reasonable queue management; and should reduce the number of extension requests.

41. ~~A fundamental assumption underlying the adopted RAM is that competition is, and will remain, vigorous in this market, with that competition resulting in just and reasonable rates and optimal resource outcomes.~~ Issues regarding jurisdiction of distribution-level interconnections have been raised in FERC Docket No. ER11-1830-000.

42. Information is vital to an effectively functioning competitive market.

43. Data on the feasibility of interconnection must be sufficiently detailed and current to be useful to potential project developers.

44. Preferred areas are likely to be those near load where the IOU has a reasonable expectation of surplus transmission or distribution capacity.

45. As renewable DG penetrations continue to increase, IOUs should evaluate and benchmark new software tools and analytics to keep pace with the expected increase in interconnection requests for small DG.

46. The Critical Infrastructure Information Act of 2002 has no bearing on the Commission's decision about whether interconnection information should be provided to potential distributed generation developers.

47. It is reasonable to allow ED to revise any aspect of the RAM program through resolutions proposed for Commission approval.

48. IOU reporting on their experience with RAM will allow the Commission, IOUs, and market to evaluate the design of the program and track its progress.

49. ~~43.~~ IOUs recover RPS program costs from bundled customers, while certain non-bypassable costs are also recovered from customers that depart from the utility bundle after new resources are procured.

~~44. The seller knows the rated generating capacity of its plant, and the contract can require this information.~~

~~45. The use of project rated generating capacity (compared to rated capacity minus a measurement or an estimate of customer load) is direct, simple, and less likely to result in uncertainty or disputes about project amounts or when maximum program capacity has been reached.~~

~~46. Not requiring the seller to be a retail customer, and not requiring the project be located on property owned or under the control of the retail customer, provides a reasonable opportunity to increase the number of potential sellers, the amount of competition, and the amount of renewable generation.~~

Conclusions of Law

1. ~~The RAM should apply to projects up to 20 MW.~~ A streamlined procurement process in the form of RAM should be implemented for smaller system-side renewable energy market.

~~**2.** The 20 MW project limit, consistent with existing FIT provisions, should apply to the amount of the transaction (i.e., the amount the IOU is buying), not the actual size of the seller's project.~~

~~**3.** Risk allocation and treatment should be addressed by contract terms and conditions rather than being a primary consideration in setting the RAM project (transaction) size.~~

2. ~~**4.**~~ A market-based pricing approach should be adopted for the RAM.

~~**5.** The RPS and QF programs are authorized pursuant to different laws, and the RPS statute provides that the RPS program does not constitute implementation of the QF program.~~

3. ~~**6.**~~ RAM avoids or eliminates a jurisdictional conflict with FERC's wholesale rate-setting authority.

4. The limitation imposed by Pub. Util. Code Section 399.15(d) on procurement of renewable energy at prices above the MPR does not apply to RAM.

5. The utilities should be required to use RAM exclusively for the procurement of system-side renewable projects up to 20 MW in size with the exception of the utility solar photovoltaic programs already authorized by the Commission as well as the annual RPS solicitations.

6. IOUs should limit their procurement of system-side renewable DG to the RAM, to annual RPS solicitations, and to Commission-approved utility solar photovoltaic programs.

7. RAM should apply only to the three largest IOUs.

8. SCE should be given the discretion to apply the contract capacity of any of the 21 contracts already executed through its 2010 RSC program to its RAM capacity cap if the contract(s) is approved by the Commission.

9. SCE should be given the discretion to submit additional contracts to the Commission for approval resulting from its 2010 RSC solicitation via a Tier 3 advice letter, however the capacity associated with these contracts should not reduce SCE's procurement obligations under RAM.

10. ~~7.~~ The following RAM ~~program~~auction design elements should be adopted: ~~a total program capacity cap~~an interim procurement requirement of 1,000 MW, subject to increase in an IOU's implementation advice letter or adjustment in any appropriate proceeding; an initial capacity allocation to the three IOUs using the same proportions as in the ~~existing~~Existing FIT program; 25% of the 1,000 MW total allocation offered in ~~the initial auction; RAM is a must-take tariff for winning bids below the SPT; and only must-take contracts apply to program capacity caps~~each RAM auction; each IOU should hold two RAM auctions per year; project bid selection based only on price with least-cost bids selected first; and IOUs can choose the types of products to solicit, subject to Commission approval; simplified contract approval through Tier 2 for RAM contracts executed up to the capacity cap authorized by the Commission for each IOU.

11. The Director of Energy Division should be authorized to explore methodologies for aligning RAM procurement authority with the Commission's procurement planning process to assess the need for RAM capacity and products in the future.

12. At any time, the Director of Energy Division may issue a resolution, either on its own motion or in response to a utility advice letter filing to update the capacity authorization.

13. An IOU should be authorized to request an increase to its capacity cap to be procured through the RAM if consistent with its portfolio need.

14. Respondents and parties may seek modification by request to the Executive Director pursuant to Rule 16.6 of the Commission's Rules of Practice and Procedure. Any modifications proposed should be based on evidence that the modification is necessary to improve the RAM program.

15. While the inputs and methodology are not in place to adopt a revenue requirement cap at this time, the Director of Energy Division may explore methodologies for aligning RAM procurement authority with the Commission's procurement planning process.

16. ~~8.~~ If an auction is less than fully subscribed, or if the subscribed capacity drops out of the program, the unsubscribed or dropped capacity should be added to the next available auction.

~~9. RAM should be limited to the three largest IOUs, deliveries should be consistent with RPS eligibility requirements as determined by CEC, and the seller should not be required to be a retail customer.~~

17. Each of the three largest IOUs should conduct two RAM auctions per year; the three IOUs should hold RAM auctions simultaneously.

18. RAM project selection should be by price with least expensive selected first.

19. Rates for RAM should be all-in energy rates adjusted by time of delivery (TOD) factors.

20. ~~10.~~ Eliminating negotiation over price, terms, and conditions as part of the RAM reasonably streamlines and simplifies this procurement option~~, and does not eliminate negotiation as part of other RPS procurement opportunities~~.

~~11. A bidder should be required to show as part of its bid that the project meets minimum project viability criteria, with failure to meet these criteria justification for an IOU to reject the bid.~~

21. ~~12.~~ RAM products should be ~~firm, non-firm~~baseload, peaking as-available, and non-~~firm non-peaking~~peak as-available electricity.

~~13. RAM project selection should be by price (least expensive selected first), with bid price expressed in cents/kWh.~~

~~14. Bid prices selected by an IOU for simplified Commission contract review should be subject to an SPT equal to 150% of MPR, updated before each auction using the most currently adopted or authorized MPRs and TOD factors.~~

~~15. Rates for RAM should be all-in energy rates by TOD.~~

~~16. Bidders should be permitted to use escalation factors in RAM bid prices.~~

~~17. Each of the three largest IOUs should conduct two RAM auctions per year beginning no later than 90 days after the last RAM tariff filed by advice letter pursuant to this order is effective; the three IOU should hold RAM auctions simultaneously; and subsequent simultaneous auctions should be held no later than every 180 days thereafter.~~

22. An IOU should define the products it would like to procure through RAM based on its portfolio need, and include this request in its implementation advice letter.

23. An IOU should be able to reject bids if it determines that one or more bids are not cost competitive or if there is evidence of market manipulation. If this occurs, the IOU should demonstrate in an advice letter filing to the Commission why bids were rejected before the capacity cap was exhausted.

24. An IOU should file all RAM contracts up to the capacity allocation approved by the Commission in response to its implementation advice letter through a Tier 2 advice letter filing.

25. A seller eligible for RAM should not be required to be a retail customer of the IOU, and an eligible project should not be required to be located on property owned or under the control of a retail customer.

26. Projects participating in RAM, either through a full buy/sell or excess sales transaction, should not exceed 20 MW.

27. ~~18.~~ Sellers selected via RAM should continue to have the choice of full buy/sell or excess sales.

~~19. A seller concentration test should not be adopted.~~

~~20. IOUs should provide reasonable information on interconnection availability at the substation or circuit level no later than 45 days before the first RAM auction (or show why it cannot be provided but revealing the best information by preferred areas), and updated no later than 90 days before each subsequent RAM auction.~~

~~21. All contracts selected via RAM should be eligible to be considered for flexible compliance.~~

~~22. The 1,000 MW RAM program cap should not be inclusive of capacity subscribed pursuant to other programs.~~

~~23. RAM should not require an eligible project to be a QF.~~

~~24. RECs should be transferred to the IOU for the energy that is purchased by the IOU.~~

28. Deliveries should be from projects located in one of the IOU's service territories.

29. Eliminating negotiation over price, terms, and conditions as part of the RAM reasonably streamlines and simplifies this procurement option.

30. Each IOU should develop its own standard RAM contract and file it as part of its implementation advice letter filing; to the greatest extent possible, IOUs should work from an existing, simple standard contract that has been vetted through a stakeholder process.

31. ~~25.~~ RAM projects should be given 18 months from contract execution to begin commercial operation or lose RAM eligibility, subject to ~~possible extensions in six-month increments at the discretion of the IOU~~one 6-month extension provided the seller can prove a regulatory delay.

32. ~~26. An~~A RAM development deposit of $20/kW for projects 5 MW and smaller, and a $60/$90 per kW for intermittent and baseload resources, respectively, for projects greater than 5 MW and up to 20 MW in size should be adopted, with this deposit either refundable upon achieving COD or applied to the subsequent performance deposit; it should be due on the date of contract execution in the form of cash or a letter of credit from a reputable U.S. bank; and it should be forfeited if the project fails to come on line within 18 months (or ~~other deadline if an~~with one six-month extension ~~has been~~if granted by the IOU).

33. ~~27.~~ For projects less than 5 MW, ~~a~~an RAM performance deposit should be adopted equal to the development deposit; for projects 5 MW and larger, a performance deposit should be adopted of 5% of expected total project revenues.

34. ~~28.~~ RAM product performance should be consistent with good utility (or prudent electrical) practices; damages should be limited to the actual, direct losses (without a maximum or minimum amount); and neither party should be liable for consequential, incidental, punitive, exemplary or indirect damages, lost profits or other business interruption damages regardless of cause.

35. ~~29.~~ RAM ~~firm~~ product performance should, in addition, require deliveries of 140% of expected annual net energy production based on two years of rolling production.

36. ~~30.~~ RAM standard contracts for the three IOUs should define and apply force majeure and events of default provisions ~~the same as, or modeled after, those used by PG&E in PG&E's existing FIT~~.

37. ~~31.~~ The RAM should require that the IOU be the seller's scheduling coordinator (unless that service is affirmatively declined by the seller, or the IOU is unable to perform the service); and the IOU, as scheduling coordinator, should bear the risk of scheduling deviations if the generator provides the IOU with timely availability information.

~~32. The RAM standard contract should include the terms used by SCE and SDG&E in their FIT (existing) standard contracts regarding termination, changes and ongoing Commission authority (§§ 4.2, 14.2 and 14.4).~~

~~33. Each IOU should bundle and file all RAM contracts with prices below the SPT in one Tier 1 advice letter within 30 days of the date of each auction, file a RAM annual report with ED beginning within 180 days of the date this order is issued, and post the annual report on its web page.~~

38. A bidder should be required to show as part of its bid that the project meets minimum project viability criteria, with failure to meet these criteria justification for an IOU to reject the bid.

39. An IOU should use pre-determined project viability screens to determine which bids are eligible to participate in the auction. These screens include: demonstration of site control upon submitting bid; demonstration of developer experience; deployment of a commercialized technology; and filed interconnection application prior to bid submission.

40. The IOUs should track project milestones and provide this information publicly using a simple format developed in collaboration with Commission staff.

41. If an IOU would like to include other bid evaluation metrics, such as seller concentration, in a RAM auction, it should propose the criteria in its implementation advice letter for Commission review; an IOU's proposal should not conflict with a price-only bid selection methodology.

42. Commission staff will consider and address interconnection issues in the future as appropriate and necessary, including, without limitation, ensuring non-discriminatory interconnection procedures based on developments in or resolution of the relevant FERC proceeding.

43. The IOUs should proactively modify their interconnection protocols for use in RAM where such modifications are reasonable and would enhance the implementation timelines and probability of success of RAM projects. The IOUs should consider adopting or modifying criteria for expedited processing where possible, either at the FERC or at this Commission.

44. IOUs should provide the "available capacity" at the substation and circuit level, updated on a monthly basis, which is defined as the total capacity minus

the allocated and queued capacity. The IOUs should provide this information in map format.

45. Each IOU should examine DG interconnection screening tools currently used to screen DG interconnection applications. The IOUs should evaluate how individual project studies could be automated to provide the requested data and a reasonable assessment of a DG project's impact on the distribution system.

46. The IOUs should work with parties and Commission staff through the Renewable Distributed Energy Collaborative (Re-DEC) or other forums in order to improve the data, usefulness of the maps, and to discuss other issues related to the interconnection of distributed resources.

47. RAM should not require an eligible project to be a QF.

48. RECs should be transferred to the IOU for the energy that is purchased by the IOU.

49. Regular reports on the RAM program are also necessary and each IOU shall provide an annual report on RAM. The IOUs may combine RAM reports with other reports, such as the annual compliance filings required in the IOU Solar PV Programs.

50. ~~**34.** The IOU annual report should include information on, and evaluation of, competitiveness, auction design, time necessary to complete~~IOUs shall work with ED to determine the content of the RAM report before filing. Among other things, the RAM report shall address the competitiveness of the auctions; auction timing and design issues; and project milestones and status, including the time and the cost necessary to interconnect and bring projects~~, auction timing, project status,~~ on-line and any other information reasonably necessary to present a complete report and allow monitoring of important program elements.

~~**35.** The first annual report should contain information, data and proposals on what defines a competitive market, how to measure competition generally, and how to measure it in the RAM market specifically.~~

51. The IOUs should hold annual program forums to solicit feedback from stakeholders regarding the RAM program design and implementation and potential modifications and refinements thereto.

52. ~~**36.**~~ IOUs and ED should make the maximum possible amount of RAM information public to, among other things, gain public acceptance of RAM.

53. ~~**37.**~~ RAM program costs should be charged to bundled customers and departing customers in the same manner as now charged.

~~**38.** The RAM rate is not governed by the IOU above market funds (AMF) cost cap.~~

~~**39.** For application toward RAM total program capacity caps, electricity sold to the IOU under either full buy/sell or excess sales should be measured by using the selling project's entire rated generating capacity (also referred to as installed or nameplate generating capacity).~~

~~**40.** A seller eligible for RAM should not be required to be a retail customer of the IOU, and an eligible project should not be required to be located on property owned or under the control of a retail customer.~~

~~**41.** IOUs should work diligently with other IOUs, ED and parties to develop, to the fullest extent feasible, one common RAM tariff, standard contract, and bid protocol.~~

54. ~~42.~~ Each IOU should, within ~~21~~60 days of the date of this order, file a Tier ~~2~~3 advice letter in compliance with the orders herein~~, parties should file protests within 20 days thereafter, and the advice letters should become effective 30 days after filing unless suspended by the Energy Division Director~~.

~~43. The first RAM auction should be held within 90 days of the date the last of the three RAM tariffs becomes effective; should be held simultaneously by all three IOUs; and subsequent RAM auctions should be held no later than every 180 days thereafter.~~

55. ~~44.~~ This order should be effective today to permit timely filing of the authorized RAM ~~tariffs~~bid protocols and standard contracts, and timely conduct of the first RAM auction, thereby providing additional tools for IOUs to reach RPS targets and goals, and helping IOUs avoid the potential of penalties for failure to reach required RPS targets.

O R D E R

IT IS ORDERED that:

1. Within ~~21~~60 days of the date this order is mailed, each electrical corporation named herein shall file and serve a Tier ~~2~~3 advice letter containing a ~~tariff (with~~ standard contract, bid protocol and any other necessary documents~~)~~ to implement the renewable auction mechanism adopted in this order.

   a. The electrical corporations are: Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company.

   b. The advice letter shall be in compliance with General Order 96-B.

   c. The ~~tariff~~standard contract and bid protocol shall be consistent with the directions stated in this decision, and summarized in Appendix A. These directions include, but are

not limited to: ~~per project (transaction) is 20 megawatts and less; rate determination is by use of the renewable auction mechanism; program cap of 1,000 megawatts, allocated to the three electrical corporations; no more, and no less, than 25% of the allocation offered in the initial auction; unsubscribed capacity (or subscribed capacity that drops out) is added to the next available auction; tariff is a must-take obligation by the electrical corporation with respect to winning bidders for all projects in a product category below the simplified preapproval threshold up to the maximum allocated capacity; bids are not negotiable with respect to bid price, terms or conditions; bidders must show within the bid that the project complies with adopted project viability criteria; electricity products eligible for purchase via this tariff are firm, non-firm peaking and non-firm non-peaking; selection of winning bids is by price (least expensive selected first); prices are subject to a simplified preapproval threshold of market price referent times 1.5 for purposes of simplified Tier 1 advice letter review; contracts with prices at or above the simplified preapproval threshold are subject to other Commission process, such as Tier 3 advice letter review or application; rates are paid on the basis of all-in energy rates by time of delivery; capacity applicable to the total statewide maximum capacity in turn allocated to each utility shall, for transactions pursuant to either the full buy/sell or excess sales options, use the project's entire rated generating capacity (also called the installed or nameplate capacity); a seller eligible to subscribe under this tariff need not be a retail customer of the electrical corporation, and the project need not be located on property owned or under the control of the retail customer; and a seller eligible to subscribe under this tariff need not be a qualifying facility under federal law.~~

~~d.~~ ~~Parties may file and serve protests within 20 days of the date of the advice letter, consistent with the provisions of General Order 96-B.~~

~~e.~~ ~~Unless suspended by the Energy Division Director, each advice letter shall become effective 30 days from the date the advice letter is filed.~~

~~f. The first auction shall be held simultaneously by the three electrical corporations no later than 90 days after the last of the three tariffs is approved. Subsequent auctions shall be held simultaneously by the three electrical corporations no later than every 180 days thereafter. The Executive Director may adjust these dates for good cause without further action by the Commission. Parties shall seek adjustment to these dates using procedures authorized by the Commission's Rules of Practice and Procedure.~~

~~g. The electrical corporations shall work diligently with each other, Energy Division and parties to develop a uniform tariff, including standard contract and bid protocol. If unable to complete this task by the time of the first auction, electrical corporations shall accomplish this goal within nine months of the date this order is mailed.~~

- rate determination is by use of the renewable auction mechanism;
- capacity limit and procurement requirement of at least 1,000 megawatts, allocated to the three electrical corporations;
- no more, and no less, than 25% of the allocation offered in each auction;
- unsubscribed capacity (or subscribed capacity that drops out) is added to the next available auction;
- two auctions per year;
- electricity products eligible for purchase via this procurement protocol are baseload, peaking as-available, and non-peaking as-available;
- selection of winning bids is by price (least expensive selected first);
- bids are not negotiable with respect to bid price, terms or conditions;
- rates are paid on the basis of all-in energy rates by time of delivery;

- contracts executed pursuant to this program to be submitted via Tier 2 advice letter;
- projects 20 megawatts and less may participate;
- standard non-negotiable contract;
- bidders must show in the bid that the project complies with adopted project viability criteria;
- a project must be located in one of the investor-owned utility service territories;
- a seller eligible to subscribe under this procurement program need not be a retail customer of the electrical corporation, and the project need not be located on property owned or under the control of the retail customer;
- and a seller eligible to subscribe under this procurement program need not be a qualifying facility under federal law.

2. The IOUs shall use an Independent Evaluator (IE) consistent with and pursuant to the requirements established in D.07-12-052, as modified by D.08-11-008 to assess the integrity and competitiveness of each RAM auction as well as to assess the appropriateness/reasonableness of the bids selected from those auctions. The IE's report shall be submitted by the respective utility to the Commission along with the Tier 2 advice letter seeking approval of contracts resulting from each RAM auction.

3. ~~**2.** Within 30 days after a renewable auction mechanism auction, each~~Each electrical corporation named herein shall file and serve one Tier ~~1~~2 advice letter with the Commission~~. The advice letter shall include~~ including all contracts resulting from the auction ~~subject to the must-take provision. Any other contract entered into by the electrical corporation at its discretion as a result of the renewable auction mechanism (such as those beyond the capacity cap or simplified preapproval threshold) may be submitted for Commission consideration by using other procedures (such as a Tier 3 advice letter or~~

~~application).~~ up to the approved capacity limits. After the effective date of this decision, the electrical corporations may not submit contracts with facilities up to 20 MW in size that are negotiated and executed outside of the Renewable Auction Mechanism program with the exception of contracts executed pursuant to the annual Renewables Portfolio Standard Program, the Commission-approved utility solar photovoltaic programs, and the contracts that Southern California Edison has or will execute pursuant to its 2010 Renewables Standard Contract program. The electrical corporations are: Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company.

4. ~~3.~~ Each year, each electrical corporation named herein shall file data, information, and evaluation in a report on relevant aspects of the renewable auction mechanism adopted in this order, and summarized in Appendix A.

a. The electrical corporations are: Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company.

b. The ~~first report shall be filed no later than 180 days from the date this order is issued, and annually thereafter. The report~~reports shall be published on the electrical corporation's website.

c. The electrical corporations shall adopt a uniform form and format in consultation with Energy Division.

~~d. Each report shall include information to monitor program design and elements. It shall include information, data and evaluation with respect to: competition, competitiveness, auction design, time necessary to complete projects, auction timing, and project status. It shall include any other relevant information, data and analysis to provide a complete report to the Commission.~~

d. ~~e.~~ Each report shall include information to monitor program design and elements. It shall include information, data, and evaluation with respect to: competition, competitiveness, and auction design. The first report shall include information and

recommendations on a definition of competition generally, a definition of competition in this market specifically, and measures of competition.

e. ~~f.~~ As data becomes available, reports shall contain information described in this order including but not limited to: measures of market competition, measures of market power, seller concentration, data on each auction (based on all bidders), data on each auction (based on projects selected), and any other data necessary to present a complete report. At a minimum, we require specific information to be revealed publicly. For all bids received and shortlisted, we require the IOUs to provide the following information: names of participating companies and the number of bids per company; number of bids received and shortlisted; project size, participating technologies, quantitative summary of how many projects passed each project viability screen, and location of bids by county provided in a map format. Finally, the IOUs must release information on the achievement of project development milestones for all executed RAM contracts.

5. The IOUs shall hold a program forum once per year, beginning after the initial RAM auctions are conducted to discuss program design and implementation, and provide opportunities for stakeholder comments. In organizing these forums, the utilities should consult with Energy Division staff and at a minimum notify the service list to this proceeding or subsequent proceedings. The IOUs may use the stakeholder feedback from each forum to develop and submit an advice letter seeking modifications to the RAM program. Similarly, Energy Division may issue a resolution on its own motion to propose program modifications based on information from these program forums or the annual reports developed pursuant to Ordering Paragraph 3 above. The IOUs may combine the RAM program forums with other program forums, such as those required for the IOU Solar PV programs.

This order is effective today.

Dated _____, at San Francisco, California.

APPENDIX A

SUMMARY OF ADOPTED ~~PROGRAMS~~PROGRAM

The attached decision ~~orders~~establishes a new ~~tariff for a~~ procurement protocol called the Renewable Auction Mechanism, or RAM. The orders, while not limited to those stated in this abstract, are summarized below. The items are generally summarized in the same sequence discussed in the attached decision.

RENEWABLE AUCTION MECHANISM

~~1. **Project (Transaction) Limit**: 20 megawatts (MW)~~

~~This is the maximum amount of the transaction (sale by the seller and purchase by the buyer):~~

~~a. For full buy/sell this is the project capacity~~

~~b. For excess sales this is the maximum amount of sales to the investor-owned utility (IOU); it is not the project capacity~~

1. ~~2.~~ **Price Determination**: Renewable Auction Mechanism (RAM)

- ~~a.~~ Projects submit price ~~**bid**~~bids
- ~~b.~~ IOUs select projects in order of least-costly first, up to program capacity limit

2. ~~3. **Program**~~**Auction Design**:

a. Program ~~**Cap**~~Procurement Requirement:

i. ~~Maximum Capacity:~~ 1,000 MW Capacity Limit

ii. ~~Program Cap~~ Adjustment to the Program Capacity Limit: May occur in any appropriate proceeding or through a Tier 3 advice letter/Resolution, or a Resolution on the Commission's own motion

iii. Capacity Allocation for total RAM program and per auction ~~:~~

UTILITY	TOTAL PROGRAM (MW)	PER AUCTION (MW)
SCE	498.4[138]	124.6
PG&E	420.9	105.2
SDG&E	80.7	20.2
TOTAL	1,000.0	250.0

iv. **Number of Auctions per Year**: Two per year, held concurrently by all three IOUs; a project may bid into all three auctions.

v. ~~iv.~~ **Amount per auction:** 25% of the total program allocation will be offered in the initial auction; unsubscribed capacity, or drop out capacity, is added to the next auction

vi. ~~v. Must Take~~**Procurement Requirement**: Each IOU must enter into a standard contract with each winning bidder ~~(i.e., RAM is a must-take obligation for the IOU relative to winning bidders;~~up to the capacity limits in each solicitation and total program capacity limits. IOUs select on the basis of least costly projects first until the IOU ~~either (a)~~ fully subscribes its allocated capacity for that auction ~~or (b) no projects remain at a price less than the simplified preapproval threshold level); only must-take contracts apply to the program capacity cap~~ . IOUs have the discretion to not enter into contracts if there is evidence of market manipulation or if the bids are not competitive compared to other renewable procurement opportunities. The IOU must submit an advice letter explaining its decision not to enter into contracts.

~~b. **Eligibility:**~~

~~i. Location: Deliveries must be consistent with RPS eligibility standards as determined by CEC~~

~~ii. Retail Customer: Seller need not be a retail customer of the IOU~~

[138] As described in the text of this decision, SCE's procurement obligation may be reduced by the capacity represented in the 21 contracts it has executed from its 2010 RSC solicitiation. Furthermore, SCE may elect to submit additional contracts resulting from its 2010 RSC solicitation via a Tier 3 advice letter, however, these additional contracts and associated capacity will not reduce SCE's procurement obligations under RAM.

iii. Utility Applicability: Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E)

c. **Uniform Terms or Uniform Contract:**

i. Initially: Each IOU starts with its existing tariff (Assembly Bill 1969), including standard contract, and implements the orders herein with terms and conditions that are as consistent and uniform as possible, using all reasonable efforts to harmonize the three tariffs (including standard contracts and bid protocols) with each other

- Tariff must employ uniform form, format and substantially common language
- ED may reject each AL with a tariff that fails to be sufficiently uniform with the other ALs, and order the IOU to re-file the rejected AL with a revised tariff

ii. Uniformity Goal: IOUs shall work diligently with other IOUs, ED and parties to make progress toward, if not reach, the uniformity goal by the filing of the first advice letter in response to this order; but shall reach the goal of a uniform tariff no later than nine months of the date of this order

d. **Negotiations:** Price, terms and conditions are not negotiable

e. **Project Viability:**

Bidder must demonstrate the following items with its bid. An IOU shall reject a bid that fails to demonstrate the following items. Each IOU shall adopt reasonable definitions and lists, as necessary (e.g., what is and is not similar technology).

i. Site Control: Bidder must show 100% site control through (a) direct ownership, (b) lease or (c) an option to lease or purchase that may be exercised upon award of the RAM contract

ii. Development Experience: Bidder must show that the company and/or development team has (a) completed at least one project of similar technology and capacity or (b) begun construction of at least one other similar project

~~iii. Equipment Standards: Bidder using solar photovoltaic equipment must show the proposed project equipment is on lists approved by the California Energy Commission and Underwriter's Laboratories; other technologies must meet similar standards if such standards exist~~

~~iv. Commercialized Technology: Bidder must show the project is based on commercialized technology (e.g., is neither experimental, research, demonstration, nor development)~~

~~v.~~ Interconnection Application: ~~Bidder must show that it has filed its interconnection application~~

b. ~~4.~~ **Products and ~~Price Design~~Selection**

- ~~a.~~ **Products**: Firm, non-firm peaking, and non-firm non-peaking electricity
  - ~~i.~~ IOU shall specify the amount of each product for the initial four auctions in the first advice letter filed pursuant to this order~~, and may not change the specified quantities~~. Utilities are required to solicit and procure capacity up to the capacity limit for each solicitation.
  - ~~ii.~~ Project must submit eligibility information (e.g., generation profile, project characteristic information) corresponding to the product bid, as established by the IOU ~~in the Commission approved tariff;~~
    ~~non-firm product unable to provide reasonable assurance that it will deliver on-peak may only participate (if it meets other eligibility criteria) as an off-peak product~~
- ~~b.~~ **Selection**: Each product is selected on the basis of price, least expensive first until the ~~MW~~capacity limit in each solicitation is reached ~~or no projects remain at a price below the applicable simplified preapproval threshold; bids are expressed and compared in cents/kWh; bid form must require bidder to state price in cents/kWh and include expected project production profile~~; IOU may normalize (adjust) bids to place bids on an equivalent basis before making least cost selection using method approved, if any, in the advice letter implementing RAM

~~c. **Simplified Preapproval Threshold**: Market price referent (MPR) times 1.5; allocated to time of delivery (TOD) periods using each IOU's~~

~~individual TOD factors; aligned to the start date and duration of the contract; updated for each auction using the most recently adopted or authorized MPR and TOD periods/factors; calculated as necessary for each project based on the project's expected production profile~~

~~d. **Rate Design**~~

~~i. All in energy (kilowatt hour) rate paid by TOD~~

~~ii. Bids may include price escalation factors~~

~~5. **Market Elements**~~

~~a. **Number of Auctions per Year**: Two per year, beginning no later than 90 days after the last of the three RAM tariffs filed pursuant to this order is effective, held concurrently by all three IOUs; a project may bid into all three auctions; subsequent auctions held concurrently no later than every 180 days thereafter; the Executive Director or Energy Division Director may adjust these dates for good cause~~

- **Independent Evaluator:** Utilities will employ an Independent Evaluator to assess the competitiveness and integrity of each RAM auction and submit the IE's report with it Tier 2 advice letter requesting approval of contracts resulting from those auctions.

3. Eligibility:

- **Location**: Combined IOU service territories (e.g. a project bidding into SCE's auction can be located in either PG&E or SDG&E's service territory).
- **Retail Customer/Third Party Ownership**: Seller need not be a retail customer and the facility need not be located on property owned or under the control of a retail customer
- **Utility Applicability**: Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E)
- **Project and Transaction Limit**: 20 megawatts (MW)

This is the maximum size for any project signing a full buy/sell or excess sales transaction through the RAM.[139]

- ~~b.~~ **Full Buy/Sell or Excess Sales**: Seller may elect either full buy/sell or excess sales

~~c. **Seller Concentration**: A seller concentration ratio is not adopted~~

~~d. **Preferred Locations**: IOU must provide information on available capacity locations at the substation or circuit level by areas (i.e., near load with an IOU expectation of surplus transmission or distribution capacity). If unable to provide data at this level, the IOU must show why it is unavailable, and provide the data at the most detailed level feasible. Over time, each IOU must increase the precision of the data and provide the data system-wide. Information to be available for the first auction as soon as possible (but no later than 45 days in advance of the initial auction), and updated no later than 90 days in advance of each subsequent auction. SCE and PG&E must incorporate data and improvements with respect to each IOU's PV program into its RAM program~~

~~e. **Project Milestones**: Bidder shall submit a project development milestone timeline to the IOU upon RAM contract signing, and quarterly progress reports must be filed with the IOU, but the only enforceable milestone is the commercial operation data (subject to certain limited extensions)~~

[139] If a project elects to pursue excess sales, the total project size, including the capacity associated with the wholesale transaction under RAM as well as the capacity associated with onsite load, is counted as part of the project's capacity for purposes of project eligibility. However, only the capacity associated with the wholesale transaction will count against the capacity limit under RAM.

~~f. **Flexible Compliance**: All RAM standard contracts are eligible to be considered for an IOU's flexible compliance in meeting RPS goals~~

~~g. **Wait List**: Not adopted~~

~~h. **Relationship to Voluntary and Other Programs**: 1,000 MW program cap does not include capacity subscribed under the existing FIT (up to 1.5 MW, subject to expansion to three MW under SB 32), nor contracts signed through an IOU's voluntary programs or other programs (e.g., CSI, NEM, SCIP)~~

~~i. **FERC Certification**: No FERC certification as a QF is required for a project to be eligible for RAM~~

~~j. **Conveyance of RECs**: RECs transferred in relationship to the amount of the purchase (for full buy/sell, the IOU buys the RECs coincident with the entire output; for excess sales, the IOU buys the RECs coincident with the purchased excess energy)~~

- **Counting Excess Sales**: Capacity associated with the transaction size is applied to the program cap.

4. RAM Standard Contract:

- **Contract Language:** IOUs can use their individual contracts, but should start with a contract that is simple, streamlined, and has already been vetted by stakeholders through another CPUC program.
- **Negotiations:** Price, terms, and conditions are not negotiable.
- ~~6.~~ **Contract Terms and Conditions**
  - ~~a.~~ **Length of Time to COD**: Within 18 months of contract execution, with ~~potential extensions for good cause (e.g., any delay outside the control of the developer may be considered, but the extension is not automatic); each extension in six-month increments at the discretion of the IOU~~one 6-month extension for regulatory delays.
  - ~~b.~~ **Development Deposit**: $20/kW~~,~~ for projects 5 MW and smaller, and a $60/$90 per kW for intermittent and baseload resources, respectively, for projects greater than 5 MW and up to 20 MW in size, refundable upon achieving commercial operation

or applied to the performance deposit; development deposit is due on the date of contract execution in the form of cash or letter of credit from a reputable U.S. bank; development deposit forfeited if project fails to come on line within 18 months or other 6-month extension granted by IOU .

- ~~c.~~ **Performance Deposit**:
  - ~~i.~~ For projects less than five MW: conversion of development deposit to performance deposit
  - ~~ii.~~ For projects five MW and larger: 5% of expected total project revenues
- ~~d.~~ **Performance Obligation**:
  - ~~i. Non-firm peaking and non-firm non-peaking:~~ Performance is required to be consistent with good utility (or prudent electrical) practices; project is obligated to have liability insurance against utility losses; the project is liable for an IOU's direct, actual losses; and project must perform consistent with generation profile or other characteristics for the product, to the extent stated in the Commission-adopted ~~tariff~~contract
  - ~~ii. **Firm**: Same as non-firm, plus minimum~~Minimum deliveries of 140% of expected annual net energy production based on two years of rolling production
- ~~e.~~ **Damages for Failure to Perform**: Damages are limited to actual, direct damages; neither party is liable ~~to~~for consequential, incidental, punitive, exemplary or indirect damages, lost profits or other business interruption damages regardless of cause
- ~~f.~~ **Force Majeure and Events of Default**: Each RAM ~~tariff~~contract shall include a force majeure definition and provision ~~equal to or modeled after that used by PG&E in its FIT (existing); other provisions related to events of default shall continue from the FIT (existing) into the RAM~~

~~g. **Insurance**: General liability insurance of no less than $2 million for facilities 0.1 MW and larger, along with necessary requirements and conditions (e.g., insurance is primary and not in excess to insurance maintained by utility); reduced amounts for facilities less than 0.1 MW~~

- **Insurance**: IOU discretion, submitted in implementation advice letter
- ~~h.~~ **Scheduling Coordinator**: ~~The~~Where possible, the contracting IOU shall be the scheduling coordinator for each project using the RAM, and the IOU shall bear the risk of scheduling deviations if the generator provides the IOU with timely information on its availability; the IOU can decline scheduling coordinator responsibilities only upon a written, affirmative request from the seller that the IOU not be the scheduling coordinator, or if unable to perform these duties

5. Project Viability Requirements

Bidder must demonstrate the following items with its bid. An IOU shall reject a bid that fails to demonstrate the following items. Each IOU shall adopt reasonable definitions and lists, related to:

- **Site Control:** Bidder must show 100% site control through (a) direct ownership, (b) lease or (c) an option to lease or purchase that may be exercised upon award of the RAM contract
- **Development Experience:** Bidder must show that at least one member of the development team has (a) completed at least one project of similar technology and capacity or (b) begun construction of at least one other similar project
- **Commercialized Technology:** Bidder must show the project is based on commercialized technology (e.g., is neither experimental, research, demonstration, nor development)
- **Interconnection Application:** Bidder must show that it has filed its interconnection application

6. Market Elements

a. **Preferred Locations**: The IOUs must provide the "available capacity" at the substation and circuit level, defined as the total capacity minus the allocated and queued capacity. The IOUs should provide this information in map format. If unable to initially provide this level of detail, each IOU must provide the data at the most detailed level feasible, and work to increase the precision of the information over time. This information is to be available in the advice letter implementing RAM and updated on a monthly basis.

i. ~~**Termination, Changes and Ongoing CPUC Authority:** The provisions in §§ 4.2(a), 14,2 and 14.4 of the existing FIT of SCE and SDG&E shall be included in the RAM for all three IOUs~~Each IOU should examine DG interconnection screening tools currently used to screen DG interconnection applications. The IOUs should evaluate how individual project studies could be automated to provide the requested data and a reasonable assessment of a DG project's impact on the distribution system.

ii. The IOUs should work with parties and Commission staff through the Renewable Distributed Energy Collaborative (Re-DEC) or other forums in order to improve the data, usefulness of the maps, and to discuss other issues related to the interconnection of distributed resources.

b. **Project Milestones**: Sellers shall submit a project development milestone timeline to the IOU upon RAM contract signing, and quarterly progress reports . The only enforceable milestone is the commercial operation data (COD) (subject to a one 6-month extension for regulatory delays).

c. **Relationship to Voluntary and Other Programs**: 1,000 MW capacity limit does not include capacity subscribed under the Existing FIT (up to 1.5 MW, subject to expansion to three MW under SB 32). SCE is permitted to draw down its capacity limit with the 21 contracts it selected in November 2010 from the RSC solicitation, if the CPUC approves these contracts

d. **FERC Certification**: No FERC certification as a QF is required for a project to be eligible for RAM

e. **Conveyance of RECs**: RECs transferred in relationship to the amount of the purchase (for full buy/sell, the IOU buys the RECs coincident with the entire output; for excess sales, the IOU buys the RECs coincident with the purchased excess energy)

7. Regulation and Commission Oversight

a. **Program modifications:** The Commission can modify any element of the program at any time through a Commission resolution.

b. ~~a.~~ **Advice Letter Review**: All executed RAM ~~must take standard~~ contracts from each auction are filed with the Commission in one Tier ~~1 advice letter within 30 days of the date of the auction; others may be entered into at IOU's discretion and may be submitted by other Commission procedures (e.g., Tier 3 advice letter or application)~~2 advice letter.

c. ~~b.~~ **Program Evaluation**: RAM to be monitored and evaluated annually, with each IOU filing a report ~~beginning within 180 days of the date this order is issued, and annually thereafter. The Executive Director may change these dates to better align with the dates of other reports~~each year. The report shall be filed with ED and posted on the IOU's website. ED shall include ~~the~~RAM program information in the Commission's reports to the legislature on the RPS program.

d. ~~c.~~ **Data**:

~~i.~~ Each annual report shall include information and evaluation on all relevant items and characteristics including but not limited to:

- Competition and competitiveness
- Auction design
- Time necessary to complete projects
- Auction timing
- Project status

- Anything else determined by ED to be necessary for a complete report

~~ii.~~ IOUs shall adopt a uniform report template with guidance from Energy Division

~~iii.~~ The first report shall include each IOU's proposal for a definition of a competitive market, proposed measurements of RPS markets generally, and proposed measurements of this RAM market specifically

~~iv.~~ As available over time, each report shall include data on:

- Measures of the requirements for a perfectly competitive market
- Measures of market power
- Seller concentration
- Data on each ~~statewide~~ RAM results
- ~~Data on each RAM result~~Information on the achievement of project development milestones for all executed RAM contracts
- Any other information necessary to present a complete report

e. ~~d. Confidentiality~~**Public release of aggregated Data**:

i. IOUs and ED shall make the maximum amount of RAM data public, ~~consistent with~~including the ~~Confidentiality Decision~~following:

~~ii. Each IOU PRG shall review RAM auction results to assess the reasonableness of the process and results including, but not limited to, whether simplified preapproval threshold and viability criteria were properly applied~~

- Names of participating companies and number of bids per company
- Number of bids received and shortlisted
- Project size
- Participating technologies
- Quantitative summary of how many projects passed each project viability screen

Location of bids by county provided in a map format

Information on the achievement of project development milestones for all executed RAM contracts

~~e.~~ **Cost Recovery**: RAM costs may be charged to bundled and departing customers consistent with current practice

~~f. **Price in Excess of MPR after AMF Exhausted:**~~
~~RAM prices and costs are not limited by the cost cap established in Pub. Util. Code § 399.14(d) regarding AMF~~

50. ~~**Counting Excess Sales**: Capacity applied to the program cap is the entire project rated (installed, nameplate) generating capacity (no different that used in the case of full buy/sell)~~**Implementation Advice Letter:** PG&E, SCE, and SDG&E shall file Tier 3 advice letters within 60 days of the date this order. The implementation advice letters shall include:

~~9. **Third Party Ownership**: Seller need not be a retail customer and the facility need not be located on property owned or under the control of the retail customer~~

Procurement protocols

RAM standard contract

Program implementation details

Timing of RAM auctions

Specific amounts of capacity and type of resources in each auction over the next two years

Explanation of any normalization procedures used for bid selection process

Detailed description of the generation profiles and characteristics that correspond with each product bucket

Description of how IOU-proposed product eligibility requirements will provide reasonable assurance that a bid for one product will, if selected, deliver energy in a manner that corresponds to the generation profile associated with that

Identify seller concentration limit, if any

Provide the preferred locations map and a description of how the maps were computed

Provide a simple methodology to measure the status of project development milestones

(END OF APPENDIX A)

APPENDIX B

ACRONYMS

ACRONYMS FOR PARTY NAMES

ACRONYM	PARTY NAME
AG	California Attorney General
AReM	Alliance for Retail Energy Markets
Axio	Axio Power, Inc.
CAC	Cogeneration Association of California
CAISO	California Independent System Operator
CALSEIA	California Solar Energy Industries Association
CARE	CAlifornians for Renewable Energy, Inc.
CEERT	Center for Energy Efficiency and Renewable Technologies
CESA	California Energy Storage Alliance
DRA	Division of Ratepayer Advocates
Environmental Council	Community Environmental Council
EPUC	Energy Producers and Users Coalition
Farm Bureau	California Farm Bureau Federation
~~FCE~~FuelCell Energy	FuelCell Energy, Inc.
~~FITC~~	~~FIT Coalition~~
~~FMG~~Fortistar Methane	Fortistar Methane Group
~~FS~~First Solar	First Solar, Inc.
GPI	Green Power Institute
GreenVolts	GreenVolts, Inc.
IEP	Independent Energy Producers Association
~~LACCD~~LA Community College District	Los Angeles Community College District
~~PacifiCorp~~	~~PacifiCorp~~
PG&E	Pacific Gas and Electric Company
Recurrent	Recurrent Energy, Inc.
Reid	L. Jan Reid
~~RR~~	~~Redwood Renewables~~

~~SA~~	~~Solar Alliance~~
~~Santa Monica~~	~~City of Santa Monica~~
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
Sempra Generation	Sempra Generation
Sempra Energy ~~Solutions LLC~~	Sempra Energy Solutions LLC
SFUI	Solutions for Utilities, Inc.
Sierra Pacific	Sierra Pacific Power Company
Sierra Club	Sierra Club ~~California~~
~~Sustainable Conservation~~	~~Sustainable Conservation~~
TURN	The Utility Reform Network
~~VSI~~	~~Vote Solar Initiative~~

OTHER ACRONYMS

ACRONYM	ITEM OR NAME
AB	Assembly Bill
ALJ	Administrative Law Judge
AMF	Above market funds
CAISO	California Independent System Operator
CCA	Community choice aggregator
CEC	California Energy Commission
CHP	Combined Heat and Power
COD	Commercial Operation Date
Commission	California Public Utilities Commission
CSI	California Solar Initiative
D.	Decision
ED	Energy Division
ERAM	Electric Revenue Adjustment Mechanism
ESP	Energy service provider
FERC	Federal Energy Regulatory Commission
FIT	Feed-in Tariff
FPA	Federal Power Act
GHG	Greenhouse gas
GW	Gigawatt
IOU	Investor-owned utility
IPP	Independent power producer
ISO 4	Interim Standard Offer No. 4
kV	Kilovolt
LCBF	Least Cost-Best Fit
LCOE	Levelized cost of electricity
LSE	Load Serving Entity
LTTP	Long term procurement plan
MPR	Market price referent
MW	Megawatt
MWh	Megawatt-hour
PIER	Public Interest Energy Research
PIRP	Participating Intermittent Resource Program
~~PPA~~	~~Power Purchase Agreement~~
PRG	Procurement Review Group

PURPA	Public Utilities Regulatory Policies Act
PV	Photovoltaic
QF	Qualifying Facility
RAM	Renewable Auction Mechanism
RD&D	Research, demonstration and development
REC	Renewable energy credit
RPS	Renewables Portfolio Standard
RSC	Renewables Standard Contract
SB	Senate Bill
SGIP	Self Generation Incentive Program
SMJU	Small and multi-jurisdictional utilities
SPP	Small power producer
~~T&C~~	~~Terms and Conditions~~
~~T&D~~	~~Transmission and distribution~~
TOU	Time of use
TOD	Time of delivery
UL	Underwriter's Laboratories

(END OF APPENDIX B)

APPENDIX C
DURATION OF PRICES AND TOD PERIODS

The Administrative Law Judge identified five rate design examples, and parties were asked to comment. (Ruling dated August 27, 2009, Appendix B.) We look at one example here. This example reveals tensions between short-term and long-term goals and responsibilities between various stakeholders. We encourage respondents and parties to continue to consider the problems identified by this example, and propose creative solutions.

In particular, respondents and parties were asked to comment on the following pricing example:[1]

- A price structure exclusively using energy payments; an initial price of $0.25/kWh paid by TOD factors set in the standard contract; the $0.25/kWh is paid in two parts over the life of the contract;
- The first part is payment of $0.20/kWh over the contract term;
- The second part is payment of $0.05/kWh; the $0.05/kWh is subject to adjustment at years 5, 10 and 15 to reflect the current market (e.g., formula in the contract based on an index to model seller's variable costs); and
- The TOD factors are updated once at year 10 to align with the current TOD profile of the buyer.

[1] August 27, 2009 Ruling, Attachment B, Item 12 at page 4 (also identified as Example D).

SCE identifies a particular problem with this example:[2]

"This example provides a fixed energy price component similar to the forecast energy price option provided to renewable Qualifying Facilities ("QF") under the Interim Standard Offer No. 4 ("ISO 4") contracts approved by the Commission in the early 1980s. As such, it embodies significant risks of overpayment for ratepayers (and a windfall for project owners) similar to those experienced during the life of the ISO 4 contracts.

The forecast energy payments under the ISO 4 agreement (which could be paid on either a levelized cents/kWh price or an escalating series of prices at the producer's election) was based on a forecast of utility avoided cost of energy that turned out to be much higher than actual market energy prices for most of the term of these contracts (which extended up to 30 years). As a result, ratepayers were saddled with overpayments for energy from these projects for many years. In light of this experience, the Commission should approach fixed payment schemes as proposed in this example with extreme caution.

More specifically, the proposal here to offer a fixed component for 80% of the energy price (*i.e.*, 20 cents/kWh) for the entire 20 year term of the contract imposes the same price risk on ratepayers for an even longer period than the ISO 4 contract did. [Footnote 20.] In addition to the extreme ratepayer risk associated with the fixed prices being above market, in the event that pricing under this example falls below market prices, project owners might be tempted to cease operating under the FIT and seek other opportunities to sell their power. Unless mitigated by appropriate security requirements or contract sanctions, this scenario would force SCE's customers to

[2] SCE Pricing Comments at 18-19.

bear the risk of having to pay for replacement power from other sources to make up the shortfall left by defaulting FIT producers. SCE strongly recommends against this scenario."

Footnote 20: Under the ISO 4 contract, the project owner was paid for energy under the forecast for a "First Period" that was limited to 10 years for contracts with a term of 20, 25 or 30 years. For contracts with a 5-year term length, the forecast was only available for the first 5 years. After the First Period, energy payments were based on avoided cost.

The risk identified by SCE is present in the current RPS program. For example, prices in the current RPS program typically are fixed for the duration of the contract, which is often 20 years. A 20-year fixed price essentially doubles the 10-year risk exposure experienced for the majority of the price under ISO 4. Further, 100% of the RPS price is fixed for the contract duration, whereas only a portion (about 20%) of the ISO 4 price was fixed for the contract duration, with the remainder (about 80%) fixed for 10 years or less, then subject to "true-up" to the market.

The fixed price risk in either the ISO 4 price or RPS price can result in either a "good" or "bad" outcome. Ratepayers will be apparent "winners," for example, if the prices set by contract for 10 years (ISO 4) or 20 years (RPS Program) turn out to be less than the market prices over the 10 to 20-year duration of the contract.[3] As SCE identifies, however, ratepayers will be apparent "losers" if the contract prices set for 10 to 20 years turn out to be more than the market prices over the same period.

---

[3] This assumes, as noted by SCE, that security requirements and contract sanctions (e.g., deposits, damages) are sufficient to prevent an owner from ceasing operations and seeking other opportunities to sell its power.

In actuality, the comparison of contract price with market price is a comparison of dissimilar products.[4] Nonetheless, it demonstrates the tension that can arise when a long-term price set by contract differs from the current market price.

A similar tension can arise relative to TOD periods. Current TOD factors place most costs in the summer on-peak period (e.g., SCE's summer on-peak factor is 3.13; PG&E's is 2.20). California has a target of reaching 20% renewables by 2010, and seeks 33% of its generation from RPS resources by 2020. If successful in reaching the 33% goal, but if done with fixed TOD periods in 20 to 25- year contracts, California will achieve 33% of California's resources delivering electricity during a fixed summer on-peak period based on TOD factors in the contract set when the contract was signed. Demand, and the demand profile by TOD, however, may change over 20 to 25 years due to many factors.[5] While stability and predictability for both buyer and seller are advanced by fixed prices and TOD periods, they can also be undermined by

---

[4] The price comparison confuses long-run and short-run (e.g., the market-based price for a 20-year contract (long-run) compared to the market-based price for a transaction of less duration (short-run, such as one day, one week, or one month); the comparison generally shows that the market-based long-run contract price is "too high" or "too low" compared to the market-based short-run price). The price comparison also confuses one long-run price with a different long-run price (e.g., market-determined contract price based on supply and demand in year x for a contract of "y" years duration compared to the market-determined contract price based on supply and demand in year x+5 for a contract of "y" years duration).

[5] If California's investment in the smart grid is successful, for example, California may be able to move the "peaking" part of the summer on-peak load to another period. If plug-in hybrid automobiles become a significant portion of California's vehicle fleet, demand in the off-peak period may grow substantially, perhaps changing the on-peak period, or at least altering TOD allocation factors. If storage technologies are successful, this may further alter demand and supply, thereby changing TOD periods or allocation factors (e.g., if plug-in hybrid automobiles are able to sell electricity back to the gird).

pre-determined, inflexible prices and TOD periods that bear little relationship to changing market conditions.[6] Changing prices and TOD periods (e.g., which results in RPS electricity being delivered in an on-peak period that is no longer on-peak) may require IOUs or developers to build additional resources to meet the changing economics and demand. Alternatively, IOUs might want or need to modify contracts with RPS resources to better match supply with demand. Contract modifications may be costly. Thus, inflexibility can lead to higher costs.[7]

Parties do not present a solution and we do not craft one here. Nonetheless, we must avoid creating an inflexible system where, if successful in reaching a 20% or 33% RPS resource base, we have fixed the economic prices and signals with contract requirements for RPS projects to sell electricity that is too expensive in the wrong TOD periods. We encourage IOUs and parties to

---

[6] See, for example, Recurrent Pricing Comments at 15.

[7] Some ratepayers would like the certainty of a rate fixed for the long term (e.g., 20 years). Similar tensions would occur, however, if the Commission set IOU ratepayer rates for the long-term. IOUs would face the risk of rates not recovering costs, recovering too much cost, or being out-of-alignment with TOD periods. We balance competing interests and adjust ratepayer rates periodically (e.g., via general rate cases every three years, or balancing accounts every year). We do not set ratepayer rates for 20 years, however (even though ratepayers make capital investment decisions for electricity consuming products which have product lives of 20 or more years).

continue to assess these concerns, and present reasonable solutions if and when appropriate, including the use of capacity rates parallel to those used in the annual RPS bid solicitation, or other devices or tools which will reasonably balance these tensions.

(END OF APPENDIX C)

Document comparison by Workshare Professional on Wednesday, December 15, 2010 10:05:07 AM

Input:	
Document 1 ID	PowerDocs://CPUC01/438966/1
Description	CPUC01-#438966-v1-R0808009_Mattson_Agenda_Dec.
Document 2 ID	PowerDocs://CPUC01/439889/1
Description	CPUC01-#439889-v1-R0808009_Mattson_Agenda_Dec._Revision_1
Rendering set	standard

Legend:	
Insertion	
~~Deletion~~	
~~Moved from~~	
Moved to	
Style change	
Format change	
~~Moved deletion~~	
Inserted cell	
Deleted cell	
Moved cell	
Split/Merged cell	
Padding cell	

Statistics:	
	Count
Insertions	1284
Deletions	1759
Moved from	170
Moved to	170
Style change	0
Format changed	0
Total changes	3383