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Renewable FIT Staff Proposal – Revised Draft

Energy Division Staff Proposal, October 13, 2011

I. RENEWABLE FIT HISTORY

Assembly Bill (AB) 1969 (Yee, 2006) added Public Utilities Code (PU Code) Section 399.20, authorizing tariffs and standard contracts for the purchase of eligible renewable generation from public water and wastewater facilities that are 1.5 MW or less.

On July 26, 2007, the Commission adopted Decision (D.) 07-07-027 ordering each regulated electric utility to submit tariff provisions implementing PU Code § 399.20. D.07-07-027 also authorized additional tariffs beyond those required for AB 1969 to customers other than the public water and wastewater customers in PG&E and SCE service territories. Resolution E-4137 approved the final tariffs and standard contracts and set the effective date of the tariffs as February 14, 2008.

Senate Bill (SB) 380 (Kehoe, 2008) amended PU Code § 399.20 to create one tariff that would apply to all utility customers. The tariff applies to SDG&E in addition to PG&E and SCE. SB 32 (Negrete McLeod, 2009) further amended PU Code Section 399.20 and increased the eligible project size to 3 MW. SB 2 (1x) (Simitian, 2011) amended PU Code § 399.20 by deleting the reference to PU Code § 399.15 and replacing the reference with the language that was formerly in PU Code § 399.15. This change is significant because it expands the options the Commission has to set the feed-in tariff (FIT) price. Rulemaking (R.) 11-05-005 is currently implementing the statutory changes from SB 380, SB 32, SB 2 (1x).

D.07-07-027 established the FIT program rules and allowed the utilities to select the state regulated Rule 21 or the federal regulated Small Generator Interconnection Procedures (SGIP) for interconnecting FIT generators. In June 2011, Sustainable Conservation filed a petition to modify D.07-07-027 and asked the Commission to order the investor-owned utilities (IOUs) to use Rule 21 to interconnect FIT generators instead of the federally regulated interconnection procedures. The Commission has not yet addressed the petition, but in August 2011, the CPUC launched a distribution interconnection settlement process to reform Rule 21 and to create one set of interconnection rules for generators interconnecting to the IOUs' distribution system.

II. PROCEDURAL BACKGROUND

On January 27, 2011 the Administrative Law Judge (ALJ) in Rulemaking (R.) 08-08-009 (the proceeding that preceded R.11-05-005) issued a Ruling asking parties to brief the changes to PU Code § 399.20 resulting from SB 32. Parties filed and served briefs and reply briefs on March 7, 2011 and March 22, 2011, respectively. On June 28, 2011, the ALJ issued a second Ruling in R.11-05-005 seeking comments on the changes to PU Code § 399.20 resulting from the passage of SB 2 (1x). Comments and reply comments were filed and served on July 21, 2011 and August 26, 2011, respectively. The IOUs filed and served proposed contracts on August 5, 2011.

III. PROPOSAL PURPOSE

The purpose of this proposal is to present parties with a comprehensive Renewable FIT program outline. Specifically, the goal is to address all of the major implementation details so that the CPUC can approve a comprehensive program with minimal staff implementation following the decision. Parties submitted extensive and comprehensive briefs and comments, which staff used to create this proposal.

IV. OVERVIEW OF EXISTING FIT PRICE AND PARTY PROPOSALS FOR AMENDED FIT PROGRAM

The Existing FIT is set at the market price referent (MPR) and adjusted for time-of-delivery (TOD) factors.[1] The MPR reflects the long-term ownership, operating, and fixed-price fuel costs for a new 500 MW natural gas-fired combined cycle gas turbine.[2] The MPR model calculates a levelized price for a proxy baseload gas-fired combined cycle gas turbine using a cash flow modeling approach. The inputs for the MPR model include installed capital costs, fixed and variable operations and maintenance costs, natural gas fuel costs, cost of capital, and environmental permitting and compliance costs. The model produces several MPR values based on a facility's online date and contract term length (i.e., 10, 15 or 20 years). The appropriate MPR value for a particular RPS project is adjusted to account for the value of different electricity products (e.g., baseload, peaking, and as-available) by applying the utilities' TOD factors.

[1] Each utility determines TOD factors based on its analysis of the forward value of energy and capacity during different times of day and times of the year. This results, in practice, in each utility valuing electricity at different hours differently. As relevant to the MPR calculation, the three large utilities use between six and nine TOD periods.

[2] More information can be found at http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr.

Parties presented a range of options to determine the Renewable FIT price for the amended FIT program, which is the most important and controversial element of the program. Parties recommend four different FIT pricing options for the amended FIT program.

a. Party Proposals

i. Option 1: Set Price at MPR

PG&E and SDG&E proposed that the FIT price be the MPR adjusted for TOD factors. Rather than establishing that the MPR is an avoided cost, PG&E and SDG&E will voluntarily offer the FIT at the MPR. TURN, CUE, and CASMU also support this position. None of these parties support augmenting the MPR price for locational value or environmental benefits.

Various parties oppose using the MPR to set the FIT price for various reasons. These parties include: AECA, CEERT, CWCCG, DRA, FuelCell Energy,[3] SCE, IREC, Sierra Club, and Sustainable Conservation.

ii. Option 2: Set Price at MPR Plus Adders

Various parties recommend the Commission set the FIT price using the MPR as the base and then adjusting the price for various adders, including TOD factors, avoided environmental externalities, locational benefits, health improvements, or job creation. These parties include: Vote Solar, AgPower, CA Farm Bureau, Clean Coalition,[4] SunEdison, CalSEIA, and Solar Alliance.[5]

iii. Option 3: Set Technology-Specific Prices Based on the Technology Costs

Various parties recommend the Commission set the FIT price based on the costs to build, operate, and earn a fair rate of return on each RPS-eligible technology. These parties include: AECA/IEUA, CEERT, CWCCG, Fuel Cell Energy, Sierra Club, Sustainable Conservation, Solar Alliance,[6] Placer County, and Renewables 100.

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[3] If MPR is used, adders must be incorporated

[4] The Clean Coalition supports using the MPR as the FIT price starting point, and then adjusting it up or down depending on program subscription.

[5] Solar Alliance supports using the MPR as a short-term solution.

[6] Solar Alliance supports technology specific rates over the long-term.

iv. Option 4: Set Price Based on Market Benchmarks

Finally, some parties recommend the Commission set the FIT price based on various market benchmarks. IREC, Silverado, Vote Solar, and SunEdison recommend the Commission set the FIT price based on the results of the Renewable Auction Mechanism (RAM) for each product category (baseload, peaking as-available, and non-peaking as-available).[7] DRA recommends the Commission set the price based on the rate used to pay net-energy metering customer generators for their excess power, which has two components: 1) the hourly day-ahead electricity market price known as the default load aggregation point (DLAP), and 2) the Department of Energy (DOE) Renewable Energy Credit (REC) price for the Western Electricity Coordinating Committee (WECC). This price is approximately 6 cents. SCE recommends a competitive procurement process for the renewable FIT generators or setting a fixed price at the South of Path 15 market price plus the DOE REC price, which would also result in a price at approximately 6 cents.

These different pricing options fall into two different categories: 1) value-based FIT (price represents the value of electricity to the utility and is derived from the IOU's avoided costs) and 2) cost-based FIT (price is derived from an individual technology's cost plus a fair rate of return). Both approaches have their pros and cons, which are listed in Table 1 below.

Table 1: Comparison of Value-Based FIT and Cost-Based FIT Pricing Options

	Pros	Cons
Value-based FIT Options 1, 2, and 4	• Protects ratepayers by not paying more than the cost of other procurement options. • Can be derived from market data, thus avoiding the need for complicated calculations or litigation. • Easy to administer. • Almost all parties agree this approach is compliant with state and federal law.	• Since price is not based on the actual project's cost, the price may be too high or too low for a specific project. This could result in an unsubscribed program or overpayment to generators.

[7] The first RAM auction will close on November 15, 2011. Pursuant to D.10-12-048 and Resolution E-4414, the IOUs will solicit renewable energy projects up to 20 MW in size and select contracts based on least total costs (bid price plus transmission costs) for each product category (baseload, peaking as-available, and non-peaking as-available).

	Pros	Cons
Cost-based FIT Option 3	• Price is likely to be high enough to stimulate development of different types of renewable technologies, projects sizes, and geographic locations.	• Price is vulnerable to litigation, which would delay program. • Price is vulnerable to industry lobbying, which could lead to overpayment. • Calculating the price is complex to administer and complicated if a separate price is needed for each project attribute (technology type, project size category, geographic region). • Some parties state that this approach is not compliant with state and federal law.

V. CPUC Staff Interpretation of Legislative Guidance

The statute directs the CPUC to consider three factors when establishing a methodology to determine the "market price" of the electricity generated by the resources covered by the statute (Renewable FIT Generators):

a. "The long-term market price of electricity for fixed price contracts, determined pursuant to an electrical corporation's general procurement activities as authorized by the commission." (PU Code § 399.20(d)(2)(A))

   - **Implication**: In setting the price, the CPUC should consider the IOUs' general procurement activities, including, without limitation, RAM auction procurement, RPS solicitation procurement, fossil-fuel procurement, or procurement in the CAISO markets.

b. "The long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities." (PU Code § 399.20(d)(2)(B)).

   - **Implication**: In setting the price, the CPUC should consider all of the costs associated with new fixed-price generating facilities, including long-term ownership, operating, and fixed-price fuel costs.

c. "The value of different electricity products including baseload, peaking, and as-available electricity." (PU Code § 399.20(d)(2)(C)).

- **Implication**: The CPUC should consider the value of different energy products and set different market prices for the different products produced by Renewable FIT Generators.

The statute provides three other points of guidance regarding the "market price" to be established by the CPUC:

d. "The commission may adjust the payment rate to reflect the value of every kilowatthour of electricity generated on a time-of-delivery basis." (PU Code § 399.20(d)(3))

- **Implication**: The CPUC can set different market prices based on TOD factors.

e. "The commission shall ensure, with respect to rates and charges, that ratepayers that do not receive service pursuant to the tariff are indifferent to whether a ratepayer with an electric generation facility receives service pursuant to the tariff." (PU Code § 399.20(d)(4))

- **Implication**: To ensure ratepayer indifference, the market price should not exceed avoided costs consistent with the Public Utility Regulatory Policies Act of 1978 (PURPA).

f. "The commission shall consider and may establish a value for an electric generation facility located on a distribution circuit that generates electricity at a time and in a manner so as to offset the peak demand on the distribution circuit." (PU Code § 399.20(e))

- **Implication:** The CPUC can provide an additional payment based on the avoided costs of a Renewable FIT Generator located in a high value location that will generate during peak demand periods. Such avoided costs include, without limitation, avoided transmission and distribution costs and line losses.

VI. Guiding Principles and Overview of Staff Proposal

a. Guiding Principles

Staff articulates the following guiding principles to guide development of the Renewable FIT Program:

1. Establish price based on market prices and quantifiable ratepayer avoided costs
2. Contain costs and ensure maximum value to the ratepayer and utility
3. Create stable and sustainable market and regulatory certainty
4. Increase program transparency

5. Comply with state and federal law and minimize legal risk
6. Ensure administrative ease and lower transaction costs for the buyer, seller, and regulator
7. Harmonize FIT with existing programs, including the RPS, RAM, IOU Solar PV Programs, combined heat and power (CHP) FIT, California Solar Initiative (CSI), Small Generator Incentive Program (SGIP), and net metering
8. Use lessons learned from existing and prior programs to inform program rules
9. Efficiently use existing transmission and distribution infrastructure
10. Strive for uniformity across the IOUs
11. Ensure all RPS-eligible renewable resources are able to participate
12. Increase probability of successful projects by establishing project viability criteria

Based on the statutory language and the guiding principles, staff proposes a value-based approach to setting the FIT price.

b. Staff Proposal High Level Overview

In order to harmonize the Renewable FIT program with other RPS programs, staff proposes to make the Renewable FIT a subset of RAM and to use the rules established through D.10-12-048 and Resolution E-4414 to the extent feasible. While not all of the rules in RAM are applicable, many of them are. Section VII of this proposal specifies what is and is not applicable.

i. <u>Base Price:</u>

- Three market prices based on the value of each renewable product: baseload, peaking as-available, and non-peaking as-available.
- Price set at the market-clearing price for RAM executed contracts for each product category for each IOU.
- Base price adjusted for TOD factors.

ii. <u>Locational Adder:</u>

- Projects located in "hot spots" are paid the avoided cost of distribution, transmission, and line losses. Hot spots are defined as areas where distribution and transmission system upgrades can be deferred if new generation is located in that area.

iii. Viability Screens:

- Sellers must meet certain viability requirements in order to be eligible for a FIT contract given the program cap.
- Viability screens should be the same as those used in the RAM program.

VII. PROGRAM ELEMENTS OF STAFF PROPOSAL

a. Pricing

Pursuant to PURPA, the seller must be a qualifying facility (QF) and the CPUC must set the price at the avoided cost in order to require the utilities purchase energy from a generator that is paid an administratively determined price. FERC recently clarified how states can set the avoided cost. Paragraph 9 of FERC Clarification Order ((2010) 133 FERC 61,059) states:

> As discussed above, permitting states to set a utility's avoided costs based on all sources able to sell to that utility means that where a state requires a utility to procure a certain percentage of energy from generators with certain characteristics, generators with those characteristics constitute the sources that are relevant to the determination of the utility's avoided cost for that procurement requirement.

This language allows the CPUC to set the renewable FIT rate based on the avoided cost of other renewable procurement options. Thus, staff proposes that the avoided cost of the Renewable FIT be based on payments made to other renewable generators.

Staff proposal

- The FIT price must be determined to be an avoided cost under PURPA. Generators must register as QFs with FERC and can utilize the **self-certification**[8] process by filling out FERC's Form 556. See Attachment B of the Ruling for an example of this form or visit FERC's website.[9]
- The renewable market is the appropriate market segment to use in determining the Renewable FIT price since renewable FIT generators are avoiding procurement of other renewable generators.

[8] FERC provides two certification options: self-certification, or FERC certification. Staff is proposing that any participating generator can self-certify instead of seeking FERC certification.

[9] How to obtain QF Status: http://www.ferc.gov/industries/electric/gen-info/qual-fac/obtain.asp

i. Determining the FIT Base Price

IREC proposed basing the Renewable FIT price on the average cost of the executed RAM contracts. Silverado and SunEdison recommended using the market clearing price, or the highest successful contract price from the RAM auction to set the Renewable FIT price. For each RAM auction, the IOUs will short-list RAM bids starting with the lowest total cost bid. Total cost is defined as the bid price plus transmission costs attributed to the particular project.

The first RAM auction will close on November 15, 2011 and the IOUs will be offering contracts to successful bids on January 15, 2012. The IOUs will submit the executed RAM contracts to the CPUC in March and April 2012. Staff agrees with the parties that RAM represents the most relevant renewable market segment that the Renewable FIT generators are avoiding since RAM is available for projects between 500 kilowatt (kW) to 20 MW.[10]

Staff proposal:

- Use the results of the RAM auction to set the Renewable FIT price for each product category (baseload, peaking as-available, non-peaking as-available).
- Use the market clearing price from each product category to set three Renewable FIT prices.[11]
- The price paid to the FIT generator will be the executed contract price plus the project's share of the transmission costs for the particular RAM contract.[12] If the generator triggers transmission costs, then the generator should receive any payment for avoided transmission.
- Adjust FIT price for TOD factors in order to capture the value of the product to ratepayers.

While there may be a time lag between the approved decision and setting the Renewable FIT price using RAM, the Existing FIT will still be available for interested developers. The Existing FIT has proven to attract program interest and development,

[10] The RAM program requires a minimum contract size of 1 MW, which can be fulfilled by aggregating two 500 kW projects.

[11] This information will not be publicly available unless the Renewable FIT decision specifically requires it to be public.

[12] When determining transmission costs, for projects that only have the Phase I or System Impact Study instead of the Phase II or Facilities Study completed, the transmission cost should be adjusted since the Phase I or System Impact Study usually overestimate transmission costs.

with 20 projects online and contracts with biogas, biomass, landfill gas, geothermal, solar thermal, solar PV, and small hydro.

ii. Locational Adder

In D.09-12-042, the CPUC determined that for combined heat and power (CHP) generators located in a local resource adequacy area, a CHP generator will receive a 10% location bonus calculated based on the facility's total energy payment. In D.10-04-055, which addressed multiple applications for rehearing, the CPUC explained why a 10% location bonus is appropriate in constrained areas. Specifically, the decision stated that CHP sited in constrained areas would provide system benefits such as transmission and distribution (T&D) upgrade deferrals and local grid stability and reliability. The CPUC used the Energy, Environment, and Economics (E3) avoided cost calculator[13] to determine the amount of this locational adder. To calculate T&D avoided costs, the E3 Calculator relies upon each utility's marginal T&D costs adopted in their general rate cases. The E3 Avoided Cost Calculator has been used and vetted in various proceedings, including energy efficiency and demand response proceedings as well as in evaluating the cost-effectiveness of the California Solar Initiative.

Furthermore, the methodology that E3 uses to calculate T&D avoided costs is consistent with the methodology articulated in a PG&E Research and Development Report titled: "Benefits of Distributed Generation in PG&E's Transmission and Distribution System: A Case Study of Photovoltaics Serving Kerman Substation."[14] This study pioneered a methodology to determine the value of a distributed solar photovoltaic (PV) power plant compared to a central station power plant. Specifically, the study quantified multiple incremental benefits of the distributed solar PV plant, including deferred distribution system upgrades and avoided line losses, and recommended further research to validate the projected benefits.

Subsequently, PG&E installed a 500 kW solar PV plant at the Kerman substation. A study was conducted to validate the results of the solar plant and its impact on PG&E's system by measuring and analyzing the actual performance data.[15] The study

[13] The avoided costs calculator is available on E3's website: http://www.ethree.com/public_projects/cpuc5.html.

[14] Shugar, D. S., Orans, R., Jones, A., El-Gassier, M. and Suchard, A., Benefits of Distributed Generation in PG&E's Transmission and Distribution System: A Case Study of Photovoltaics Serving Kerman Substation, PG&E R&D, Report 007.5-92.9, November, 1992.

[15] Farmer, B.K., Wenger, H.J., Hoff, T.E., and Whitaker, C.M., Performance and Value Analysis of the Kerman 500 kW Photovoltaic Power Plant. Presented at the American Power Conference Sponsored by Illinois Institute of Technology Chicago, IL, April, 1995. Available online: http://www.cleanpower.com/Content/Documents/research/distributedgeneration/KermanAPC.pdf

combined measured data with existing utility engineering models and improved evaluation techniques to determine the operational effect of the solar PV plant on the utility system. Next, the study combined the technical results with economic models to estimate the plant's value to the utility. This report concluded that:

- "Data analysis and testing confirm that non-traditional Benefits [avoided costs], in addition to traditional benefits, are measurable, predictable, and significant for grid support PV;
- Non-traditional benefits double the overall value of the Kerman plant relative to a traditional central station resource planning perspective; and
- Methods to evaluate the Kerman grid-support plant are repeatable and generally applicable to other forms of distributed resources and applications."

Based on conclusions of these studies and the CHP FIT program Decisions, staff agrees that generators located in high value locations, or "hot spots,"as defined by E3, should receive an additional payment for their locational value. Even if RAM projects are located in a hot spot, the RAM price will likely not reflect this value since the generator determines the RAM price based on the project's costs instead of its avoided costs. In addition, most RAM projects will likely not be located in a hot spot.

Staff proposal:

- Generators located in hot spots should receive an additional payment, which should be based on the generator's product category and the estimated avoided or deferred T&D costs and line losses calculated for the hot spot.
- While the CPUC estimated the locational bonus based on the E3 Avoided Cost Model in the CHP FIT proceeding, staff has worked with E3 to determine location-specific values for the avoided T&D costs for each product category (baseload, peaking as-available, and non-peaking as-available). See Attachment C of the Ruling for an overview of the methodology and results and Attachment D for a more detailed description of the Locational Adder (avoided T&D and line losses) methodology.
- The IOU distribution engineers should use the methodology E3 articulates in Attachment C to identify the hot spots that receive the locational value estimated in the E3 analysis. SCE should identify hot spots that cover 10% of its load, and PG&E and SDG&E should identify hot spots that cover 5% of their load in order to maximize the locational adder and limit project locations to where they can defer an upgrade. The IOUs should work with CPUC staff to confirm that their calculations conform with E3's methodology. The IOUs can update the avoided distribution system cost numbers based on more recent data, but most work with

staff to ensure that the reason for the change is based on new or updated cost information.

iii. Price Adjustment

Once the CPUC sets the FIT price, the CPUC needs to determine how to adjust the price in the future. The MPR, which is the Existing FIT price, is updated based on current natural gas prices after each RPS solicitation, typically once a year. For the amended Renewable FIT price, parties have suggested a range of options including adjusting the price once a year using the data from the most recent RAM auction to automatically increasing or decreasing the FIT price based on market response.

Automatically increasing or decreasing the price based on the market response is an elegant and simple solution to responding to the market, although it must be balanced with the need for a sustainable and long-term market signal to incentivize development and investment. The CSI program pioneered the decreasing cost approach based on capacity trigger. The CSI incentives decrease after a certain capacity is fulfilled in each IOU's territory for each customer category.[16] This method proved to be very successful since it decreased ratepayer costs without negatively impacting the market response.

Staff proposal:

- The Renewable FIT price for each product category for each IOU should be increased or decreased after a certain subscription (or lack thereof) occurs.
- This type of trigger mechanism will help adjust the Renewable FIT price in the case that the initial base price is too high or too low.

Parties should review and comment on the existing party proposals or provide their own proposal. See below for a description of the existing party proposals on the record.

Party proposals:

CalSEIA

In CalSEIA's March 7, 2011 brief, CalSEIA proposes that the Commission allocate the total program capacity over a period of five quarters (1.25 years). If any single calendar quarter is oversubscribed, the Commission should automatically reduce the FIT rate by 10% for the following calendar quarter. Conversely, the Commission should leave the rate unchanged if it finds that there is little or no market activity.

[16] Information on the CSI trigger is available here: http://www.csi-trigger.com/.

SCE

In SCE's August 5, 2011 standard contract and tariff filing, SCE proposes that the FIT price increase or decrease based on program subscription. Specifically, SCE articulates the following proposal:

a. Market Price Adjustment - The initial market price (MP) FIT price will be published on the first business day of the first full calendar month following the effective date of this Schedule, and a new MP FIT price will be published on the first business day of each month thereafter. The monthly MP FIT price will be available to eligible applicants for fifteen business days on a first-come, first-served basis. Each month, SCE will execute PPAs with eligible applicants who have given written notice to SCE of their acceptance of the MP FIT price in the order of the applicant's MP FIT Number until SCE's cumulative program procurement has reached the lesser of the Cumulative Procurement Target or the MP FIT Cap. Eligible applicants who are not awarded a PPA may continue to participate in the MP FIT from month-to-month, and will retain their MP FIT Number, except as otherwise specified in this Schedule. The MP FIT price will be adjusted according to the rules below:

   (1) There must be at least five sponsors and ten eligible projects for any price adjustment to be considered. If there are less than five eligible sponsors and ten eligible projects for any monthly offering, then the MP FIT price will remain the same the next month.

   (2) If SCE is below its Cumulative Procurement Target and no applicants have accepted the current MP FIT price, the MP FIT price will be adjusted up $2/MWh the following month.

   (3) If at least one applicant has accepted the MP FIT price and executed a PPA but the Cumulative Procurement Target has not been reached, then the MP FIT price will remain the same the next month.

   (4) If the Cumulative Procurement Target has been exceeded, then the MP FIT price will be adjusted down $2/MWh the next month.

b. Cumulative Procurement Target – Each month, SCE's cumulative procurement target will equal to 1/48th of SCE's allocated share of the statewide program cap of 750 MW times the number of months since the effective date of this Schedule (Cumulative Procurement Target).

c. Transmission Cost Factor – SCE will determine a transmission cost factor for each Eligible Electric Generation Facility based on the network upgrade costs specified in the facility's most current interconnection study or agreement (Transmission Cost Factor), and will inform each facility of its Transmission Cost

Factor simultaneously with the issuance of the MP FIT Number. The Product Price in the executed PPA will equal the accepted MP FIT price adjusted by the Transmission Cost Factor.

Vote Solar

In Vote Solar's August 27 Reply Comments, Vote Solar states: "for each utility territory (and for each product category), if the initial price were insufficient to stimulate demand, the price would adjust upwards a reasonable amount (we suggest 5%) a month until there is market activity."

Clean Coalition

In the Clean Coalitions June 21 Comments, the Clean Coalition made the following proposal, suggesting that similar to the CSI program, the digression is specific to each utility.

First half of each IOU's share	2009 MPR plus TOD
Third quarter of each IOU's share	Minus 5% from 2009 MPR
Fourth quarter of each IOU's share	Minus 10% from 2009 MPR

b. Program Cap

PU Code 399.20

> "(f) An electrical corporation shall make the tariff available to the owner or operator of an electric generation facility within the service territory of the electrical corporation, upon request, on a first-come-first-served basis, until the electrical corporation meets its proportionate share of a statewide cap of 750 megawatts cumulative rated generation capacity served under this section and Section 387.6. The proportionate share shall be calculated based on the ratio of the electrical corporation's peak demand compared to the total statewide peak demand."

i. <u>Calculating the IOU Share of the Program Cap</u>

This language is almost identical to the language in AB 1969 that established the FIT program. The only differences are the original program cap, which was 250 MW, and the publicly-owned utilities were not required to offer a FIT. D.07-07-027 allocated the program cap through the following methodology:

- Each electrical corporation provided the California Energy Commission (CEC) with its system demand for retail service load (including bundled service, direct access, and community choice aggregation).
- The CEC used this information to allocate the 250 MW of program capacity and reported the shares back to each participating electrical corporation.

Parties previously agreed to this methodology and as result, staff proposes to retain this methodology.

Staff proposal:

- Determine IOU share of the program cap by working with the CEC to determine the IOUs share of statewide system demand for retail service load.

ii. Program Cap Limit

Some parties proposed that the CPUC increase the IOUs' share of the FIT procurement requirements beyond the 750 MW stating that SB 32 created a new FIT program. Staff does not agree with this interpretation since SB 32 amended PU Code 399.20 and did not create a new FIT program.

Staff proposal:

- The current program cap is the IOUs' proportionate share of 750 MW. Both existing and new contracts executed pursuant to 399.20 will count towards this cap since SB 32 and SB 2 (1x) did not create a new program but amended the existing program.

iii. Increasing the Program Cap

Regarding party comments to increase the cap beyond the IOUs' share of 750 MW, PU Code 399.15 directs the CPUC to establish a cost limitation for the RPS program as a whole and states that all RPS eligible procurement will contribute to the cost limitation:

> "The commission shall establish a limitation for each electrical corporation on the procurement expenditures for all eligible renewable energy resources used to comply with the renewables portfolio standard." 399.20(c)
>
> "The costs of all procurement credited toward achieving the renewables portfolio standard are counted towards the limitation." 399.20(d)(2)

Staff proposal:

- Based on the language in 399.15, staff proposes that the IOUs can raise the FIT program cap, but a planning process is necessary to evaluate the costs and

benefits of increasing the program cap relative to other renewable procurement options and the total RPS program cost limitation.

- Two forums are: 1) R.11-05-005 implementation of 399.15, which provides parties an opportunity to compare procurement from different renewable market segments in order to determine the best approach and overall cost limitation for the 33% RPS, and 2) the long-term procurement planning proceeding (LTPP),[17] which also evaluates the costs of the RPS program.

c. Project Size Limit: 3 MW

Public Utilities (PU) Code § 399.20

> "(1) Has an effective capacity of not more than three megawatts.
>
> (2) The commission may reduce the three megawatt capacity limitation of paragraph (1) of subdivision (b) if the commission finds that a reduced capacity limitation is necessary to maintain system reliability within that electrical corporation's service territory."

Staff proposal:

- The project size limit should be 3 MW. The IOU interconnection study will determine the requirements for a generator to maintain system safety and reliability, and as a result, it is not necessary to limit the size of participating generators to less than 3 MW.

d. Product Categories

As specified in PU Code § 399.20(d)(2)(C), the CPUC can consider "The value of different electricity products including baseload, peaking, and as-available electricity." As stated previously, staff proposes to set three product categories: baseload, peaking as-available, and non-peaking as available. These are the same products used in the RAM program. In the RAM program, the IOUs choose how much of each category they wish to solicit based on the value of the product to their system and their need for that type of renewable product.

Staff proposal:

- In order to harmonize this program with RAM, the IOUs should determine how much of each product category to contract with based on the product's value to

[17] R.10-05-006

the utility and the utility's need. However, the IOUs should allocate a minimum amount to each product category.

e. Contract

Various parties stated in the July 21 comments that they preferred the contract that PG&E submitted for "projects up to 1 MW" compared to the other IOU contracts. Parties also requested the use of one contract for all IOUs. Staff agrees that one contract will help simplify the program and lower the transaction costs for the seller.

Staff proposal:

- All IOUs should use PG&E's contract for "projects up to 1 MW" for all project sizes.[18] See Attachment E to review PG&E's contract for "projects up to 1 MW."
- In order to harmonize the Renewable FIT program with RAM, the IOUs should offer contracts of 10, 15, and 20 years to both new and existing generators.
- The excess sales option should be retained.

f. Contract Terms and Conditions

i. Development Deposit

Parties suggested either $20/kW or $50/kW. A development deposit is needed to ensure sellers are serious and committed to the project. A relatively high development deposit can help mitigate against contract failure. On the other hand, a high development deposit can deter customers developing smaller projects (less than 1 MW) from participating in the program.

Staff proposal:

- The IOUs should require a $20/kW development deposit for projects less than 1 MW and a $50/kW development deposit for projects between 1 MW and 3 MW.

ii. Performance Standards

399.20(j)(1) "The commission shall establish performance standards for any electric generation facility that has a capacity greater than one megawatt to ensure that those facilities are constructed, operated, and maintained to generate the expected annual net production of electricity and do not impact system reliability."

[18] See PG&E's August 5, 2011 filing in the docket for R.11-05-005 to review PG&E's.

In its March 7 Brief, PG&E proposes a performance standard of 140% of guaranteed energy production over a two-year period for non-baseload facilities and 180% of the contract capacity over a two-year period for baseload facilities. Staff agrees with PG&E that these terms are commercially reasonable and appropriate.

Staff proposal:

- The performance standard for projects over 1 MW should be 140% of guaranteed energy production over a two-year period for non-baseload facilities and 180% of the contract capacity over a two-year period for baseload facilities.

iii. Telemetry

In August 26 Reply Comments, SunEdison states that costs of telemetry are very high relative to the cost of a small project (in the range of $150,000). SunEdison proposes that the issue of telemetry should be addressed in the distribution interconnection settlement process and that telemetry should not be required for projects less than one MW. SunEdison also states that if telemetry is required, the contracts should specify the data needed, which should not exceed the CAISO's requirements.

Staff agrees that requiring telemetry can be a significant cost burden for small projects. On the other hand, it is important for the IOUs to be able to monitor and control these systems for purposes of system reliability. Thus, it is important to balance the need for advanced communications with the costs of the technology.

Staff also agrees that this issue is more appropriately addressed in the distribution interconnection settlement process. Since the timing of the settlement is unclear, this issue must be addressed now for purposes of the contract. SunEdison's proposal for the IOUs to specify the needed data, which should not exceed the CAISO's requirements, is reasonable.

Staff proposal:

- The IOUs should specify the needed communications data, which should not exceed the CAISO's requirements.

iv. Other Modifications to PG&E's Contract

AECA filed a matrix recommending changes to PG&E's FIT contract for "projects up to 1 MW" in order to modify the contract so that projects up to 3 MW can use the contract. AECA suggested additional changes as well. See Attachment F of this Ruling to review the matrix.

g. Transition from Existing FIT to Amended FIT

SCE's Existing FIT program, called CREST, requires a completed interconnection agreement before a seller can execute the FIT contract. As a result of this criterion, many sellers that are currently developing projects for the CREST program do not have executed contracts with SCE. In contrast, PG&E does not have this criterion and has over 100 MW of renewable contracts. In fact, PG&E has reached its program limit for non-water and waste-water customers.[19] Silverado has suggested that developers that submitted an interconnection under SCE's CREST program before August 26, 2011 should be able to receive a FIT contract for projects up to 3 MW at the current MPR.

While Silverado's suggestion has merits, CREST developers have been aware of the change in law since the end of 2009. As a result, developers currently in the interconnection queue should be subject to the program rules determined in this proceeding.

Staff proposal:

- Once the new rules are in place, all generators will be subject to the same rules. The only exception is the location restriction, which is articulated in Section VII, j of this proposal.

h. Interconnection

i. <u>Interconnecting Tariff</u>

The CPUC's Rule 21 was established to interconnect QFs pursuant to PURPA. Since staff is proposing that the pricing mechanism for the Renewable FIT be set at the avoided cost of other renewable procurement, this proposal is compliant with PURPA. As a result, generators should interconnect under Rule 21. The CPUC is currently updating Rule 21 for exporting generators through the Distribution Interconnection Settlement process (formerly the Rule 21 Working Group) and has issued an Order Instituting Rulemaking (OIR), R.11-09-011, to resolve interconnection-related issues. There may be a lag, however, between the Renewable FIT program start date and the establishment of new interconnection rules.

Staff Proposal:

- Generators can choose to apply for interconnection through either Rule 21 or the Wholesale Distribution Access Tariff (WDAT) until new interconnection

[19] PG&E still has approximately 100 MW available for water and waste-water customers.

procedures under Rule 21 are in place. Once Rule 21 procedures are in place, all generators participating in the FIT should interconnect through Rule 21.

ii. Expedited Interconnection

In addition to determining which interconnection process to use, the statue directs the IOUs to offer expedited interconnection to generators that meet certain criteria.

> PU Code § 399.20(e) "An electrical corporation shall provide expedited interconnection procedures to an electric generation facility located on a distribution circuit that generates electricity at a time and in a manner so as to offset the peak demand on the distribution circuit, if the electrical corporation determines that the electric generation facility will not adversely affect the distribution grid.

Staff proposal:

- Defer addressing this language on expedited interconnection, since these issues should be resolved in the Interconnection OIR/Distribution Interconnection Settlement. If these issues are not resolved through these process in a timely manner, than this proceeding can revisit this issue in 2012, as initially proposed in the ALJ's June 28, 2011 Ruling.

Lastly, the statute states that all generating capacity shall count toward the utility's resource adequacy (RA) requirement.

> PU Code § 399.20 (i) "The physical generating capacity of an electric generation facility shall count toward the electrical corporation's resource adequacy requirement for purposes of Section 380."

The IOUs have stated that in order to count a generator for RA, the California Independent System Operator (CAISO) must deem the generator deliverable. In order for this to occur, the CAISO must complete a deliverability study, which will take almost two years to complete and could result in costly upgrades. In staff's view, this type of study is overly burdensome from a time and cost perspective for small generators that are strategically located. Staff rejects the IOUs' proposal that all FIT generators must be deliverable in order to participate in the program. Instead of offering a proposal, staff seeks proposals from parties on how to address this statutory requirement.

i. Project Viability and Queue Management

Various parties, including the Clean Coalition, SunEdison, Fuel Cell Energy, CEERT, Vote Solar, CalSEIA, and Silverado propose some degree of project viability requirements. Staff agrees with the need for project viability criteria and proposes the following criteria, which are mostly consistent with the RAM program. The only difference is the bid fee and seller concentration, which are not a requirement in the RAM program.

i. Bid fee
   a. $2/kW (Clean Coalition, SunEdison, FCE, CEERT)
ii. Interconnection
   a. System Impact Study, Phase I study, or passed the Fast Track screens (SunEdison, Silverado, Vote Solar)
iii. Site Control
   a. Attest to: 100% site control through (a) direct ownership, (b) lease or (c) an option to lease or purchase that may be exercised upon contract execution.
iv. Development Experience
   a. 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.
v. Commercialized Technology
   a. Project is based on commercialized technology with at least two installations in the world.
vi. Online Date
   a. 18 months with one 6-month extension for regulatory delays (Clean Coalition)
vii. Seller Concentration
   a. CalSEIA and PG&E suggested a seller concentration cap of 10 MW per seller. Staff agrees that there should be limit, but recommends a different metric. Staff proposes a seller be limited to 25% of an IOU's total capacity cap.

j. Program Location Restrictions

The statute specifically directs electric generation facilities to be strategically located. This language was in AB 1969 and was not initially implemented, although this language is in the IOUs' existing tariffs.

> PU Code § 399.20(b) "As used in this section, 'electric generation facility' means an electric generation facility located within the service territory of, and developed to sell electricity to, an electrical corporation that meets all of the following criteria:
>
> Is strategically located and interconnected to the electrical transmission and distribution grid in a manner that optimizes the deliverability of electricity generated at the facility to load centers." PU Code § 399.20(b)(3)

In addition, the statute allows the IOUs to deny tariff if the project adversely affects the grid.

> An electrical corporation may deny a tariff request pursuant to this section if the electrical corporation makes any of the following findings:
>
> The transmission or distribution grid that would serve as the point of interconnection is inadequate. PU Code § 399.20(n)(2)
>
> The aggregate of all electric generating facilities on a distribution circuit would adversely impact utility operation and load restoration efforts of the distribution system. PU Code § 399.20 (n)(4)

Staff Proposal:

- The Renewable FIT program should limit procurement to generators that are "strategically located" and that optimize "the deliverability of electricity generated at the facility to load centers."
- In order to reduce uncertainty and increase transparency, the program should determine up front project locations that would not be subject to IOU tariff denial.

In order to implement this language, SCE proposes to limit FIT procurement to its preferred locations in its Solar PV and RAM Circuit Maps for interconnection requests made after August 5, 2011. SCE is making this proposal since many of the projects seeking interconnection for the CREST program are located in rural areas with weak distribution systems. Staff agrees that it is prudent to restrict projects to preferred

locations based on direction from the statute and SCE's experience with the CREST program. Staff would like to further explore SCE's proposal at the September 26, 2011 Workshop.

Staff also offers an alternative methodology. In order to implement this statutory language, staff defines "strategically located" as projects that serve load in order to avoid adverse impacts to the distribution and transmission system. Thus, a project should not exceed the minimum load at the substation. This type of requirement pre-determines that the grid is adequate and that the generation will not adversely impact utility operation. In addition, as parties state in the record, the purpose of the interconnection study is to determine the upgrades needed to ensure the generator will not adversely impact utility operation and load restoration efforts. Thus, if this requirement or a similar requirement is implemented, the IOUs cannot deny tariffs based on 399.20 (n)(2) and (n)(4).

A third option is to limit generators to the hot spots that the IOUs will develop for a certain percentage of their service territory's load (5% for PG&E and SDG&E and 10% of SCE) in order to incentivize generators to locate in areas where distribution upgrade deferral is possible.

Instead of staff proposing a preferred option, parties should comment on the strengths and weaknesses of each option and propose an additional option if desired.

k. Data Reporting

For all executed contracts (even terminated contracts), IOU should post to the internet the following information within 10 days of IOU contract execution:

- Seller Name
- Project Name
- Status (On Schedule, Delayed, Operational, Terminated)
- Capacity AC (MW)
- Expected Energy Production (GWh/yr)
- Technology
- Contract price (includes locational adder, $/MWh)
- Vintage (existing, restart, repower, new)
- Contract Term (years)

- Location (City, County)
- Contract Execution Date (date)
- Actual Online Date (date)
- 6 month extension (yes or no)

l. Other Issues

i. Inspections

Staff proposal:

- Parties suggested the CPUC create a uniform reporting format Parties should work together to create a uniform reporting format and submit it in their comments to this Ruling.

ii. Dispute Resolution

Staff proposal:

- If the dispute occurs before contract execution, parties should use the CPUC's complaint process. Once the contracts are executed, the contract dispute provisions control the dispute resolution process.

VIII. PROPOSAL QUESTIONS

Please respond to each question and explain your response with data and analysis.

RAM Pricing

1. How should the CPUC set the price if an IOU does not execute any contracts in one or more product categories? For example, the IOU could use the price from another one of its product categories.
2. How should the CPUC adjust the transmission part of the total RAM price if the generator only has a Phase I or System-Impact Study, since the results of these studies are usually an overestimate of actual transmission costs?

Pricing Adders

3. If the CPUC adopts the locational adder, what should the CPUC do to increase the probability that a distribution system upgrade will be deferred?

Besides a locational adder, staff is not proposing other adders to the FIT price. If parties believe the Commission should consider other adders, then parties should address the following issues when suggesting an adder:

4. Does the technology have an incremental avoided cost compared to a RAM project in the same product category? If so, explain why.
5. Is the adder avoiding a ratepayer cost? In staff's view, any additional FIT adder should avoid a ratepayer cost and not a more general societal cost since the statute requires that ratepayers be held indifferent to the FIT payments.
6. Can the adder be quantified? If so, suggest a method and the data sources for quantifying the adder. Reference previous filings if applicable.

Pricing Trigger:

7. Identify the strengths and weaknesses for each party's proposal listed in the staff proposal, and make a recommendation addressing the following issues:
    a. Level of subscription that triggers price decrease
    b. Amount that the price should be decreased
    c. Time period without any or minimal subscription that the price should be increased
    d. Definition of minimal subscription

FIT Contract

8. Do parties agree or disagree with the Agricultural Energy California Association's proposed modifications to PG&E's contract?
9. If you seek additional modifications to PG&E's contract or any other contract filed in the record, identify the term, proposed change, and rationale in a matrix format. To ensure your recommendation receives full consideration, provide documentation or attestation to support your rationale. In addition, if you propose a modification, you should state if the language is from a previously approved contract and provide the citation. When reviewing contract language, staff considers the following guiding principles to determine if a change is warranted:
    a. Term properly allocates risk between buyer, seller, and the regulator
    b. Term minimizes transaction costs between buyer and seller

c. Term is financeable and provides regulatory certainty

Resource Adequacy

10. How should the CPUC implement PU Code § 399.20 (i), which states: "The physical generating capacity of an electric generation facility shall count toward the electrical corporation's resource adequacy requirement for purposes of Section 380?"
11. Should this issue be addressed in other planning proceedings, such as the LTPP and RA proceedings? To what extent is there overlap with the Distribution Interconnection Settlement process? What is an appropriate interim approach. If you support addressing this issue in other, more appropriate proceedings, provide a rationale and an interim proposal to address this language before it is addressed elsewhere.

Implementing Strategically Located:

12. How should "strategically located" be defined and implemented?
13. Comment on the strengths and weaknesses of each option listed in the staff proposal. If you have an alternative proposal, explain the rationale and the data sources required to implement it.

CSI/SGIP/NEM Refund Options

14. Over what time period should incentives be refunded? What is the rationale for your time period versus the alternatives presented in the record?
15. Which incentives should be refunded and why?
16. At what interest rate should incentives be refunded and why?

(END OF ATTACHMENT A)

ATTACHMENT B