Renewable FIT Staff Proposal – First Draft[1]

Energy Division Staff Proposal – September 23, 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 Section 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 Section 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 Section 399.15 and replacing the reference with the language that was formerly in 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

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[1] A revised draft will incorporate workshop comments and will be served to parties through a Ruling in R.11-05-005 seeking post-workshop comments. Given the goal to mail a proposed decision before the end of the year, parties will have a shortened time period to comment.

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 a very limited implementation process following the decision. Parties submitted extensive and comprehensive briefs and comments that 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.[2] 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.[3] 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.

[2] 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.
[3] 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

Option 1: Set Price at MPR

PG&E and SDG&E proposed that the FIT price be the MPR adjusted for TOD factors. Instead of determining 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,[4] SCE, IREC, Sierra Club, and Sustainable Conservation.

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, SunEdison, CalSEIA, and Solar Alliance.[5]

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

[5] Sola Alliance supports using the MPR as a short-te rm solution.

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

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 establish a methodology to determine the "market price" of the electricity generated by the resources covered by the statute (Renewable FIT Generators), in consideration of three factors:

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 generated by a Renewable FIT Generator located in a load pocket that will generate during peak demand periods. Such avoided costs include, without limitation, avoided transmission and distribution costs and line losses.

<u>Additional CPUC Staff Conclusions:</u>

The language of PU Code §§ 399.20(d) and (e) provides significant specific guidance to the CPUC in establishing market prices for eligible generators, including examination of the value of different electricity products, including baseload, peaking, and as-available electricity. However, Staff's opinion is that while technology-specific pricing may be an option under § 399.20, the law does not direct it.

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:

- Establish price based on market prices and quantifiable ratepayer avoided costs
- Contain costs and ensure maximum value to the ratepayer and utility
- Create stable and sustainable market and regulatory certainty
- Increase program transparency
- Comply with state and federal law and minimize legal risk
- Ensure administrative ease and lower transaction costs for the buyer, seller, and regulator
- 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
- Use lessons learned from existing and prior programs to inform program rules
- Efficiently use existing infrastructure
- Strive for uniformity across the IOUs
- Ensure all RPS-eligible renewable resources are able to participate
- 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 and proposes that the FIT price be determined using the following fundamental building blocks.

b. Staff Proposal High Level Overview

<u>Base Price:</u>

- Three market prices based on the value of each renewable product: baseload, peaking as-available, and non-peaking as-available.
- Base price adjusted for TOD factors.

Locational Adder:

- Projects located in high-value areas are paid the avoided cost of distribution, transmission, and line losses. High-value areas are defined as areas that can avoid distribution and transmission system upgrades if new generation is located there.

Viability Screens:

- Sellers must meet certain requirements in order to be eligible for a FIT contract given the program cap.

VII. Program Elements of Staff Proposal

a. Pricing

Pursuant to PURPA, the seller must be qualifying facility (QF) and the CPUC must set a price at the avoided cost in order to require the utilities to execute a contract with 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 avoided costs of other renewable procurement. 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.
- Since Renewable FIT generators are avoiding procurement of other renewable generators, the renewable market should be used to determine the Renewable FIT price.

Determining the FIT Base Price

IREC proposed basing the Renewable FIT price off of 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. 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 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 IOUs will submit the executed RAM contracts to the CPUC in March and April of 2012.

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.[8]
- The price paid to the FIT generator will be the executed contract price plus the transmission costs for the particular RAM contract.
- Adjust FIT price for TOD factors in order to capture the value of the product to ratepayers.

Table 2: Evaluation of using RAM to Set the FIT Price

	Evaluation of Using RAM to Set the FIT Price
Pros	• Easy to administer • RAM reflects most recent renewable market data • FIT price will represents the IOUs' avoided renewable procurement costs
Cons	• Time lag between anticipated proposed decision (end of 2011) and submitted RAM contracts (April 2012) • Revealing highest RAM contract price may lead to gaming at a future RAM auction • IOUs may not execute any contracts in one or more product categories • Eligible RAM projects are up to 20 MW instead of 3 MW, which could lead to lower pricing due to economies of scale

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

Workshop Discussion Questions to Overcome the Cons:

- Should the CPUC set an interim FIT price based on a different renewable benchmark in the time between the approved decision and the submitted RAM contracts?
- Will revealing the highest total cost (executed contract price plus transmission costs) help mask the bid price in order to prevent gaming in the next RAM auction?
- How should the CPUC set the price if an IOU does not execute any contracts in one or more product categories?
- Should the CPUC adjust the RAM price in order to take into account the differences in economies of scale of small versus larger projects? If so, how should the CPUC do that while keeping other ratepayers indifferent?

Locational Adder

In D.09-12-042, the CPUC determined that for CHP generators located in a local resource adequacy, a CHP generator will receive a 10% location bonus calculated based on the facility's total energy payment. In D.10-04-055, the CPUC determined that a 10% location bonus is appropriate in constrained areas because CHP sited in these 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) Model to determine the amount of this locational adder. To calculate T&D avoided costs, the E3 Model relies upon each utility's marginal T&D costs adopted in their general rate cases. In the CHP FIT proceeding (R. 08-06-024), the IOUs argued against such a T&D avoided cost on the basis that such costs are highly site-specific and that a case-by-case analysis is needed.
Staff agrees that generators located in high value locations should receive an additional payment for their locational value to the extent that the RAM price does not reflect this value. In most cases, the RAM price will likely not reflect this value. For example, the lowest cost RAM bids in the peaking as-available category are likely to be solar PV projects located outside of load centers due to land constraints and lower solar insolation in load centers. Thus, in this example, peaking as-available FIT projects located in highly value location should receive payment for the locational value.

Staff proposal:

- Generators located in high value locations should receive an additional payment, which should be based on the generator's product category and the estimated avoided transmission and distribution costs of the generator's specific location.

- 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). E3 will present this methodology at the Workshop.

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 (SCE, Vote Solar, and CalSEIA). 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 incentive development and investment.

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.

Workshop Discussion Questions:

- What is a reasonable price increase or decrease rate?
- After what level of subscription should the price be decreased?
- After how much time without any subscription should the price be increased?

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."

Calculating the IOU Share of the Program Cap

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.

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.

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:

"(c) 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.

(d) (2) The costs of all procurement credited toward achieving the renewables portfolio standard are counted towards the limitation."

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) when implementing 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)[9], 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. 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.

[9] R.10-05-006

Staff proposal:

- All IOUs should use PG&E's contract for "projects up to 1 MW" for all project sizes.[10]

e. Contract Terms and Conditions

Development Deposit

Parties suggested either $20/kilowatt (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.

Staff proposal:

- The IOUs should require a $50/kW development deposit.

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."

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.

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

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

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:

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

<u>Other Modifications to PG&E's Contract</u>

AECA filed a matrix recommending changes to PG&E's FIT contract for projects up to 1 MW. AECA recommends using that contract for all utilities and for all project sizes. See Attachment A.

Workshop Discussion Questions

- Do parties agree or disagree with AECA's proposed modifications to PG&E's contract?
- Do parties suggest any other modifications to PG&E's contract?

f. TRANSITION FROM EXISTING FIT TO NEW 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.[11] Silverado has suggested that developers that

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

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.

g. Interconnection

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 for other renewable procurement, this proposal is compliant with PURPA. As a result, generators should interconnection 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 a proposed Order Instituting Rulemaking (OIR) in order to resolve interconnection-related issues. However, there may be a lag between the Renewable FIT program start date and the establishment of new interconnection rules. As a result staff recommends:

- Generators can choose to apply for interconnection through either Rule 21 or the Wholesale Distribution Access Tariff (WDAT) until new interconnection procedures under Rule 21 are in place.

In addition, there is specific language about interconnection in the statute.
399.20 states:

"(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.

(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."

Staff proposal:

- Defer addressing this language now, since these issues should be resolved in the Interconnection OIR.

- Furthermore, 399.20 (i) was in the original bill that established PU Code Section 399.20 (AB 1969). The existing program does not require a deliverability study in order to count the generation towards resource adequacy requirements. Thus, staff rejects the IOUs' proposal to require a deliverability study and proposes no change to the Existing FIT on this issue.

h. Project Viability and Queue Management

Various parties, including the Clean Coalition, SunEdison, Fuel Cell Energy, CEERT, Vote Solar, 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 consistent with the RAM program.

- <u>Bid fee</u>

  $2/kW (Clean Coalition, SunEdison, FCE, CEERT)

- <u>Interconnection</u>

  System Impact Study, Phase I study, or passed the Fast Track screens (SunEdison, Silverado, Vote Solar)

- <u>Site Control</u>

  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.

- <u>Development Experience</u>

  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.

- <u>Commercialized Technology</u>

  Project is based on commercialized technology with at least two installations in the world.

- <u>Online Date</u>

  18 months with one 6-month extension for regulatory delays (Clean Coalition)

- <u>Seller Concentration</u>

  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 10% of the capacity available under each product category.

i. **Program Location Restrictions**

"399.20 Section 3 (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:

(b)(3) 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."

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

399.20 states:

"(n) An electrical corporation may deny a tariff request pursuant to this section if the electrical corporation makes any of the following findings:

(n)(2) The transmission or distribution grid that would serve as the point of interconnection is inadequate.

(n)(4) The aggregate of all electric generating facilities on a distribution circuit would adversely impact utility operation and load restoration efforts of the distribution system. "

Staff Proposal:

- 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).

Staff Proposal:

- Limit project eligibility to 100% of the minimum load of the substation.
- The CPUC has received this data from the IOUs in response to the Interconnection Data Request (sent on April 27, 2011).

j. Data Reporting

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

- 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)

k. Other Program Issues to Discuss at the Workshop

CSI/SGIP/NEM Refund Options

- Time period?
- Which incentives should be refunded and why?
- At what interest rate?

Inspections

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

Dispute Resolution

- Use CPUC's complaint process

ATTACHMENT A

Agricultural Energy Consumers Associations (AECA)
Proposed Modifications to PG&E's Contract for "Projects up to 1 MW"

Filed on August 26, 2011 as Attachment A to AECA Reply Comments to Sec. 399.20 Ruling

PG&E Tariff/PPA Section	Comment re proposed modification or omission	Recommendation
RATES	Proposed revisions are acceptable except that reference to the MPR should be removed.	…at the applicable ~~Market Price Referent (MPR)~~ price…
SPECIAL CONDITION 1	Remove reference to two separate PPAs.	
SPECIAL CONDITION 2	Revise to remove language inconsistent with section 399.20.	Remove "or other similar programs."
SPECIAL CONDITION 4	Replace with language consistent with section 399.20(e) and CPUC implementation of "expedited interconnection" rules	TBD
SPECIAL CONDITION 8	Proposed new language is acceptable except that section 399.20(m) does not require publication of customer name or address.	Delete ~~customer name~~ and renumber.
SPECIAL CONDITION 9	Proposed new language is acceptable with revisions. While the 4 denial criteria are consistent with section 399.20, two of them will be implemented through the interconnection process and so are not appropriate here.	PG&E may deny a customer's request for a Small Renewable Generator PPA if PG&E determines that (1) the electric generation facility does not meet the requirements of this Schedule and/or Public Utilities Code Section 399.20; or (2) ~~the transmission of distribution grid that would serve as the point of interconnection is inadequate; (3)~~ the electric generation facility does not meet all applicable state and local laws and building standards ~~and PG&E interconnection requirements, or (4) the~~

		~~aggregate of all electric generation facilities on a distribution circuit would adversely impact utility operation and load restoration efforts of the distribution system.~~
SPECIAL CONDITION 11	Proposed new language is acceptable with revisions to make it consistent with section 399.20(p). The Commission should approve one standard form for all IOUs.	The customer shall provide to PG&E on a~~n~~ bi-annual basis an inspection and maintenance report for the electric generation facility. The report shall be submitted on a form approved by the CPUC and provided by PG&E. The report shall be prepared at the customer's expense by a California licensed contractor who is not the customer. ~~PG&E shall provide to the customer a form inspection and maintenance report, which may be updated from time to time by PG&E at its sole discretion.~~
2.1.4 Facility Nameplate Capacity	E-SRG should be available to all eligible projects up to 3 MW.	Revise last sentence to read: "The Nameplate Capacity will not exceed 3,000 kW.
2.2 Transaction	See previous comment	See previous recommendation
2.7 No Additional Incentives	Existing section 2.7 is not consistent with PU Code § 399.20(k)	~~No~~ Additional Incentives. Any Seller that received ratepayer-funded incentives ~~Seller agrees that during the Term of this Agreement, Seller shall not seek additional compensation or other benefits~~ pursuant to the Self-Generation Incentive Program, as defined in California Public

		Utilities Commission ("CPUC") Decision ("D") 01-03-073 (SGIP), or the California Solar Initiative, as defined in CPUC D.06-01-024 (CSI), or PG&E's net energy metering tariff, prior to January 1, 2010, shall be eligible for this contract. ~~or other similar California ratepayer subsidized program relating to energy production with respect to the facility~~.
3.3 Resource Adequacy Benefits	Correct citation	In accordance with PUC Section 399.20~~(g)~~(i)…
3.5 Eligible Intermittent Resource Protocol ("EIRP")	PG&E has eliminated reference to EIRP due to proposal to limit PPA to 1 MW or less. If the "two PPA" approach is rejected, EIRP may remain in the PPA. However, this section should be modified to make it clear that EIRP only applies to wind and solar resources.	If Section 3.5 is retained, add clarification that only EIRP-eligible intermittent resources are subject to this requirement.
4.3.1 Representation and Warranty	Existing section 4.3.1(a) is not consistent with section 399.20. Replace existing subsection (a) in its entirety with language that reflects PU Code § 399.20(k)(2)	If the Facility previously received payments pursuant to Public Utilities Code § 379.6 or Public Resources Code § 25782, the Facility has either (a) reimbursed such funds or (b) received a waiver of reimbursement from the CPUC under Public Utilities Code § 399.20(k)(2) and in accordance with any applicable CPUC requirements.
5.1 Facility Care, Interconnection and Transmission Service	Proposed new language requiring a CAISO Participating Generator Agreement or	Eliminate proposed modification

	demonstration that it is "ineligible" under the CAISO tariff to receive a PGA is not required under SB 32.	
Proposed new Section 10.1: "Guaranteed Commercial Operation Date"	Proposed new language is acceptable with modifications. The word "guaranteed" and "time is of the essence" are not necessary. Insofar as both have specific meanings under statutory and common law, inclusion in this agreement may lead to confusion and litigation. We only agree to limiting extensions for "Transmission Delay" (or more accurately, "Interconnection Delay") IF Rule 21 reform is implemented concurrently with SB 32. Otherwise, the contract should allow extension beyond 6 months for Interconnection Delay outside control of the Seller.	• Eliminate the word "Guaranteed" – adds unnecessary ambiguity • 10.1: eliminate first sentence agreement that "time is of the essence" – unnecessary and likely to lead to disputes.
Proposed new Section 10.2	The proposed requirement of notice of permitting or interconnection delay by six months after the execution date is not realistic. The need for an extension will probably not be apparent a full year ahead of time.	Replace "the date that is six (6) months after the date the Execution Date" with: as soon as practicable or in any event no later than 30 days prior to the forecasted Commercial Operations Date, …
Proposed new Section 13	Proposed language is acceptable with modifications consistent with section 399.20(p).	13. BI-ANNUAL INSPECTION REPORTS. Seller shall provide to PG&E on the first anniversary of the Commercial Operation Date,

		and in ~~each~~ every other Contract Year thereafter during the Delivery Term, an inspection and maintenance report regarding the Facility. PG&E shall provide to the Seller an ~~form~~ inspection and maintenance report form that is consistent with requirements established by the CPUC before the Commercial Operation Date and Seller shall complete the form inspection and maintenance report. ~~PG&E, at its sole discretion, may modify the form inspection and maintenance report to be used in subsequent Contract Years during the Delivery Term.~~
Appendix A	New proposed definition of "Guaranteed Commercial Operation Date" is duplicative, unnecessary, and might cause confusion and litigation.	Eliminate proposed definition of "Guaranteed Commercial Operation Date' on page 4 of Appendix A.