FILED
07-09-08
04:59 PM

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	Rulemaking 06-05-027 (Filed May 25, 2006)

OPENING COMMENTS OF THE VOTE SOLAR INITIATIVE AND RECURRENT ENERGY, INC. ON THE ISSUES REGARDING PHASE 2 OF TARIFF AND STANDARD CONTRACT IMPLEMENTATION FOR RPS GENERATORS

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Date: July 9, 2008

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In accord with the June 4, 2008, Amended Scoping Memo and Ruling of Assigned Commissioner Regarding Phase 2 of Tariff and Standard Contract Implementation for RPS Generators (Ruling), The Vote Solar Initiative (Vote Solar) and Recurrent Energy, Inc. (Recurrent) (hereinafter, the Joint Solar Parties) submit these opening comments addressing issues regarding tariff and standard contract implementation for RPS generators contained in Attachment A of the Ruling. The Joint Solar Parties appreciate the opportunity to provide these comments.

On July 9, 2008, counsel, acting on behalf of Vote Solar and Recurrent, pursuant to Rule 11.6 of the Commission's Rules of Practice and Procedure, by way of oral motion to Presiding Administrative Law Judge Mattson, requested authority to file these opening comments six days out of time. ALJ Mattson granted such motion. Accordingly, these comments are properly filed.[1]

[1] It should be noted that these comments were originally served on July 3, 2008 on behalf of the Solar Alliance, The California Solar Energy Industries Association, GreenVolts, as well as Vote Solar and Recurrent. Due to a procedural irregularity the comments are being filed and served today solely on behalf of Vote Solar and Recurrent.

I. COMMENTS

1. Extend tariff to other customers of five utilities: Should the existing program for other (non-water/non-wastewater) customers of Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) be extended for other customers of San Diego Gas & Electric Company (SDG&E)?

1.1 Should the tariff/standard contract opportunity available to water/wastewater customers be extended to other (non-water/nonwastewater) customers of SDG&E?

The Joint Solar Parties believe that the tariff/standard contract opportunity should be extended to non-water/non-wastewater customers or other third-parties in SDG&E's service territory. Decision no. (D.) 07-07-027 limited the tariff for such customers in SDG&E's service territory stating that "…. SDG&E and others should focus their attention on larger projects."[2] However, according to the CPUC website[3], SDG&E has only 5.3% of their 2006 retail electricity sales coming from renewable power as of August 2007. In the April 2008 CPUC Quarterly Renewable Portfolio Standard Report to the Legislature[4], the need for transmission upgrades was identified as a major area of concern. It is also well-known that the need for transmission upgrades is a major concern and an impediment to renewables development in SDG&E's territory. As explained more fully in these comments, tariff/standard contracts have great potential to quickly bring small renewable energy projects online by 2010 as they are not reliant on transmission upgrades if they are sited on the distribution system. This benefit extends to the San Diego basin. Therefore, simplified contracting through the offering of a tariff/standard contract with uniform terms and conditions should be offered in SDG&E's service territory similar to the programs currently in place in the service territories of PG&E and SCE.

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[2] D.07-07-027 at p. 48.

[3] Available at http://www.cpuc.ca.gov/PUC/energy/electric/RenewableEnergy/progress.htm.

[4] Available at http://www.cpuc.ca.gov/NR/rdonlyres/2DBB287C-6DE9-4574-97D4-AA7F16996D3B/0/RPS_Rpt_to_Legislature_April_2008.DOC.

1.2 If so, should the extension be on the same basic terms and conditions as employed for water/wastewater customers, and as extended for PG&E and SCE?

The Joint Solar Parties believe that the basic terms and conditions for the tariff/standard contracts developed in this proceeding should be consistent across the IOUs' service territories. Consistency, simplicity, and transparency in program requirements will facilitate participation by small renewable developers.

1.3 Is there anything else the Commission should consider when deciding whether or not to expand the opportunity to other customers of SDG&E?

2. Increase the Project Size to 20 MW: Should the project size eligible for the tariffs/standard contract be increased from 1.5 MW to 20 MW?

2.1 Identify and, where possible, quantify the advantages and disadvantages of expanding the minimum size for projects which may qualify for this tariff/standard contract from 1.5 MW to a higher MW amount, up to and including 20 MW.

The Joint Solar Parties support an expansion in tariff/standard contract eligibility to include larger systems. The Joint Solar Parties believe an expanded tariff/standard contract will offer many benefits to California not the least of which is an increase in the state's ability to meet its ambitious RPS goals. According to the 2007 Integrated Energy Policy Report ("IEPR"), "[a]n expanded use of feed-in tariffs can stimulate the robust pace of renewable energy development needed to achieve 33 percent renewables by 2020."[5] Accelerated deployment of renewable resources will also enable California to achieve its AB 32 greenhouse gas reduction goals and foster development of clean distributed generation ("DG") in furtherance of the goals articulated in the Commission's Energy Action Plan II.[6]

[5] 2007 IEPR at p. 147.

[6] D.07-09-040 at p. 119.

There has been repeated recognition by the Commission that renewable generators under 20 megawatts are disadvantaged in utility RPS solicitations. The Commission acknowledged this disadvantage when it established its Future Policy and Pricing for Qualifying Facilities in D.07-09-040. In that decision, the Commission established certain contract requirements for QFs up to 20 megawatts in recognition of the fact that "a small QF is unable to bid in a utility RFO, generally does not have the resources or expertise to negotiate with a utility, and is prohibited by current rules from selling surplus generation directly to the CAISO."[7] The Commission reiterated this concern in its Opinion Conditionally Accepting Procurement Plans for 2008 RPS Solicitations. In that decision, the Commission recognized that "in order to meet the hundreds of megawatts (MW) embedded in the 20% by 2010 objective, utilities primarily need (and general want) to devote limited time and resources to bid processing and LCBF analysis for larger rather than smaller projects."[8]

Southern California Edison ("SCE") has also acknowledged the challenge faced by small renewable generators. In May 2007, SCE established a Biomass Program that offers standard contracts for biomass projects up to 20 megawatts. SCE's motivation for establishing this program stemmed in part from a recognition that standard offer contracts for small biomass generators were needed to address difficulties smaller biomass projects have in participating in SCE's annual solicitations and to eliminate the complex negotiation process required of larger generators.[9] According to the California Energy Commission, as of June 2008, SCE has eleven MW under contract, another 23 MW in negotiation, and 22 MW of inquiries under SCE's

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[7] D.07-09-040 at pp. 118-19.

[8] D.08-02-008 at p. 30.

[9] Id. at p. 42.

Biomass Program.[10] This response shows that developers of smaller renewable projects respond to simplified procedures for RPS contracting when they are made available.

From a small project developer's perspective, RPS solicitations are costly and involve sorting through complex documents, attending bidders conferences and/or workshops, preparing documents, and engaging in post-bid negotiations.[11] The smaller a project, the more likely it is that profit margins will be eaten up by the transaction costs associated with participating in an RPS solicitation. Expanded tariff/standard contract eligibility will remedy this problem by ensuring that small renewable generators have a simplified and streamlined mechanism to sell electricity to a utility without complex negotiations or delay. The Commission's standard QF contracts and SCE's standard biomass contracts exemplify the benefit contract certainty provides in helping developers finance small renewable energy projects. Without this certainty, project financing is contingent on a developer's ability to successfully compete in a utility RPS solicitation and negotiate contract terms that will allow project costs to be financed. As with the standard contracts used for QFs and biomass projects, standard contracts offered on a tariffed basis lift this cloud of uncertainty and ensure that small renewable projects can get built. The 2008 IEPR concurs in noting that "[b]y reducing uncertainty in a project's income stream, feed-in tariffs help developers obtain lower cost financing and stimulate investment in a domestic renewable energy market."[12]

An expanded tariff/standard contract will also help California maintain its leadership position in clean technology innovation. Presently, developers seeking to deploy

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[10] See Notice of Staff Workshop: Renewable Energy "Feed-In" Tariffs, Docket 08-IEP-1 and Docket No. 03-RPS-1078, mailed June 20, 2008.

[11] D.08-02-008 at p. 30.

[12] 2008 IEPR at p. 12.

innovative grid-scale technologies are at an acute disadvantage in RPS solicitations. As the Commission noted in D.08-02-008, "the focus of RPS solicitations is largely intended to be on commercially viable projects..."[13] Developers looking to demonstrate the viability of a new renewable energy technology in a small-scale demonstration project face a significant barrier in being able to prove up the technological viability of their product. California's lack of support for these new market entrants raises the possibility of a reduction in technology innovation, a loss of green collar job growth and a barrier to clean technology investment in the state. The Joint Solar Parties believe an expanded tariff/standard contract can remedy this problem by ensuring a mechanism exists to facilitate innovative commercial demonstration projects on a small scale.

Finally, an expansion in tariff/standard contract eligibility will foster the development of clean distributed generation in furtherance of the goals articulated in the Commission's Energy Action Plan II.[14] Distributed renewable generation has the potential to offer many benefits to California. Distributed generation is strategically located and interconnected in a manner that optimizes delivery to load. As such, distributed generation offers locational benefits that include: (i) increased capacity of distribution transformers at the generation site and at the substation level during peak periods, which reduces line losses and increases transformer life; (ii) avoided distribution system upgrades when DG is located on areas of the distribution grid (or feeders) that are capacity constrained; (iii) avoided transmission system upgrades that are required to access large-scale renewable resources located far from load; (iv) meeting local resource adequacy needs; (v) reducing congestion costs; and (vi)

[13] D.08-02-008 at p. 31.

[14] See D.07-09-040 at p. 119.

reducing transmission line losses.

The ability to obtain QF status by small renewable generators does not address many of these issues. While it is true that many small RPS projects also could qualify as QFs, and may be able to obtain standard contracts under the terms of D.07-09-040, the IOUs have made clear that they intend to seek the termination of the PURPA must-purchase obligation in California once the CAISO's day-ahead market under MRTU is functioning.[15] New Section 210(m) of PURPA, enacted as part of the Energy Policy Act of 2005, allows a utility to petition FERC to end the PURPA must-purchase obligation, upon a determination by the FERC that QFs in the utility's service territory have nondiscriminatory access to wholesale energy markets.[16] The utilities assert that the MRTU DA market will meet the criteria specified in Section 210(m). Additionally, FERC's Order 688 implementing Section 210(m) does include a "rebuttable presumption that the requirement that an electric utility enter into new contracts or obligations to purchase from a QF remains in effect, *in all markets*, for QFs sized 20 MW net capacity or smaller." However, this presumption can be rebutted upon demonstration by the electric utility "with regard to each small QF that it, in fact, has nondiscriminatory access to the market."[17] Given the California utilities' longstanding hostility to purchasing power from QFs, the Commission cannot be certain that the utilities will not seek to rebut this presumption in their petition to terminate the PURPA must-purchase obligation in California.

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15 For example, in the proceedings in R. 04-04-025, the IOUs took the position that the Commission should not approve new long-term standard contracts for QFs in California, because they expected that the PURPA purchase obligation would expire in California within as little as one year, i.e. upon the implementation of MRTU. *See* D. 07-09-040, at 19.

16 16 U.S.C. §824a-3, subd. (m)(1).

17 FERC Order 688, 71 Fed. Reg. 64352 (emphasis in original).

Moreover, D.07-09-040 allowed the IOUs to refuse to purchase power from new QFs if they determined, with the concurrence of their Procurement Review Group, that the QF power is not needed. However, the Commission did not apply this provision to small, under-20-MW QFs, so long as the aggregate amount of QF capacity does not exceed 110% of current amounts (about 8,655 MW).[18] This would allow about 866 MW of new QFs before small QFs would be subject to this "need hurdle."[19] Nonetheless, there clearly are limits on the potential availability of QF contracts for small renewable generators. D.07-09-040 approved standard contracts for new QFs with maximum terms of ten years, but the bulk of the payments under such contracts are short-run avoided cost (SRAC) energy payments that are indexed to monthly spot prices for natural gas. As a result, the prices available to new QFs will vary with natural gas prices. Given the capital-intensive nature of most renewable technologies, renewable developers prefer contracts with terms substantially longer than ten years (20 – 30 years) and with fixed prices that do not vary with gas prices. The QF contracts approved in D.07-09-040 may work for new CHP projects, and may encourage the repowering of existing QF contracts, but are unlikely to stimulate the development of new small renewable generation.

2.2 Recommend whether or not to increase the maximum size here from 1.5 MW to a higher amount, and state the specific MW amount.

The Joint Solar Parties support an increase in tariff/standard contract eligibility to 20 MW. The Solar Parties believe that such an increase reflects the utilities' resources needs and market conditions. A 20 MW eligibility limit also reflects a growing consensus that successful

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[18] D 07-09-040, at Table 5.

[19] See D. 07-09-040 at 123-124. The order is unclear on whether this 866 MW is intended to be reserved for small QFs only, or is intended to represent the overall growth of QFs of all sizes.

participation in an RPS solicitation is unlikely for generators under 20 megawatts.[20] An increase in tariff/standard contract eligibility to 20 MW also reflects the recommendation of the 2008 IEPR.[21]

2.3 If the minimum size of projects that may qualify for tariffs/standard contracts is increased, address whether or not this should be implemented within (a) the existing program (250 MW for water/wastewater, 228.4 MW for other) or (b) as a separate new program. If a separate new program, please state specifics (e.g., program limits, proportional allocations, if any).

The minimum size of projects should be increased to 20 MW and this change should be implemented within the existing program, provided the program limits are increased (see answer to 2.4, below). Modifying an existing program will reduce administration costs and speed implementation.

2.4 If the minimum size of projects that may qualify for tariffs/standard contracts is increased above 1.5 MW within the existing program, address whether or not existing overall program limits and proportional allocations should continue or be modified (i.e., program limits of 250 MW for water/wastewater customers and 228.4 MW for other customers; proportional allocations of 123.8 MW for SCE, 104.6 MW for PG&E, 20.1 MW for SDG&E, and so on). Please state specific reasons in support of either continuation or modification. If modified, please state specific recommended modifications, with support.

Existing program limits should be expanded to accommodate a greater number of larger systems and to make significant progress toward achieving California's RPS goals. Proportional allocations should be maintained, but utilities should be allowed to exceed their proportional allocation at their discretion. Joint Solar Parties observe that any program cap should recognize that the IOUs presently procure just 13.2% of their generation from qualified renewable sources,[22] and thus there is room for significant additional procurement of renewable

[20] See D.07-09-040 at pp. 118-19; D.08-02-008 at p. 42.

[21] See 2008 IEPR at p. 147.

[22] Available at http://www.cpuc.ca.gov/PUC/energy/electric/RenewableEnergy/compliance.htm.

generation. In addition, renewable procurement is tracked closely and this program is limited to small projects, so there is little chance that a "gold rush" of small projects would result in an oversubscription of renewable generation.

Increasing program limits is necessary to accommodate increased system size. A limit of 228.4 MW could lead to as few as 12 systems installed statewide, if each system were sized to the maximum allowed. A program that allowed merely a dozen larger systems would fail to fully maximize the benefits associated with widespread distributed generation. Further, 228.4 MW of additional renewables, while significant, will not make an appreciable dent in the utilities' projected shortfall in renewable procurement.

The Joint Solar Parties believe two methodologies for setting the cap are available. The first is based upon the current shortfall in utility renewable energy procurements. The second is based on a percentage of the utilities' RPS goals.

According to the March 2008 RPS Compliance Reports submitted by PG&E, SCE and SDG&E, California's largest utilities were short of their RPS procurement targets by 2.8 million MWh in 2007.[23] This is the equivalent of 1,900 MW of PV generation.[24] Flexible compliance rules notwithstanding, the utilities have a very significant challenge in meeting their 20% goal, not to mention the State's aspiration to achieve 33% renewables. A program cap in the 1,500 MW to 2,000 MW range would allow solar technologies to make a quick and significant contribution to the existing shortfall in RPS procurement.

Alternatively, the program cap could be set as a percentage of RPS procurement. Based on combined Annual Procurement Targets (APTs) of 22.4 million MWh in 2007[25], a 10%

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[23] Available at http://www.cpuc.ca.gov/PUC/energy/electric/RenewableEnergy/compliance.htm.

[24] Assuming 17% capacity factor.

[25] Available at http://www.cpuc.ca.gov/PUC/energy/electric/RenewableEnergy/compliance.htm.

target implies approximately 1,700 MW[26] for solar technologies. The target will be higher based on 2010 APTs, but only one of the three utilities provided 2010 APT information. Based on historic sales growth rates from 2003 through 2007 and the 20% goal, a 10% solar PV target would be approximately 2,500 MW. This would contribute less than 2% toward the 20% RPS goal, and is only a portion of the additional renewable generation that the IOUs must acquire to reach the 20% goal.

Basing the program limit on the RPS goals does not create a link between the AB1969 tariff and the RPS program. Rather, it uses the RPS program as a reference point to provide a meaningful limitation on the tariff/standard contract program. Properly implemented, the tariff/standard contract program provides an additional tool to help California meet its RPS goals while avoiding needless delays caused by contract approval, permitting or transmission queue delays.

2.5 If the minimum size of projects that may qualify for tariffs/standard contracts is increased above 1.5 MW within the existing program, should projects above 1.5 MW be required to use a feed-in tariff or should they also be allowed to participate in the standard RPS solicitations?

Projects larger than 1.5 MW should be allowed the option to participate in either the tariff/standard contract or standard RPS solicitations. Although projects from both the RPS and tariff/standard contract programs will be used to meet the utilities' RPS targets, the contracts used in each program are different. Some projects may need or desire the greater contracting flexibility available through the standard RPS solicitation compared to the standard contract available through the tariff/standard contract program. There is no downside to the utility or ratepayers in permitting small renewable generation this option since any project submitted through the standard RPS solicitation must abide by the solicitation schedule and pass the same

[26] Assuming 17% capacity factor.

competitive screens to which other RPS proposals are subject.

2.6 How does the price, terms and conditions offered under the feed-in tariff compare to the following:

2.6.01. The price paid for the 51 RPS projects selected that are under 20 MW?

The Commission should examine these projects carefully, and should not conclude from this sample that small projects can easily obtain contracts under existing RPS procedures. Of these 51 projects, 44 are listed as "active" contracts. Of these, 21 are existing projects that are either re-starting, re-powering, or expanding their production. These existing projects represent 69% of the MWs in this group of active projects. The 23 new, small projects developed under the RPS program to date total just 90 to 107 MWs of capacity, and average about 4.3 MW in size. Most of the projects are small biogas or biomass projects; there are just three small solar contracts and no small wind contracts. There clearly is a much greater potential for small renewable generation in California that is not being developed under the current RPS program.

Moreover, among the 23 new, small projects developed under the RPS program to date, 6 contracts are priced at or above the applicable MPR, 9 are priced below the MPR, and the remaining prices are either unknown or were priced in reference to the $53.70 per MWh 5-year fixed SRAC price for QF power that became effective in 2001 and that was a pricing benchmark for renewable energy before the Commission began to approve the MPR. The Joint Solar Parties are aware that the three small solar contracts[27] and the one small wave energy contract[28] that are above the MPR were justified to the Commission in part because they represent the first

[27] GreenVolts, CalRenew, and California Sunrise 1.
[28] Finavera.

commercialization of promising new technology.

2.6.02. The price paid for RPS projects over 20 MW?

The larger database of all RPS projects shows that 18% of RPS projects are priced above the MPR, 73% are below the MPR, and the pricing in 9% is unknown. The percentage of projects priced above the MPR appears to be a lower percentage among all RPS projects than it is for the smaller sample of the new RPS projects under 20 MW. However, given the lack of detailed, public price data and the relatively small sample sizes (particularly for RPS projects smaller than 20 MW), it is difficult to draw firm conclusions from this data.

2.6.03. The price paid for qualifying facility projects in D.07-09-040?

The Joint Solar Parties have compared two types of pricing for a ten-year contract starting in 2009 (the 2007 MPR and QF pricing under D.07-09-040) for two types of generation profiles (a base load profile and the typical profile for a solar photovoltaic [PV] project). This comparison uses the same set of natural gas prices – the gas price forecast adopted with the 2007 MPR. The results of this comparison are shown in **Attachment A - Table 1**. The average prices for the solar profile differ appreciably between the utilities as a result of the different sets of time-of-use factors used by each utility.

Generally, the all-in QF prices adopted in D.07-09-040 are 1% to 16% lower than the 2007 MPR.[29] The Joint Solar Parties note that the capacity prices adopted in D.07-09-040 are based on combustion turbine costs from 2005 and combined-cycle costs from the 2006 MPR. Power plant costs have escalated sharply over the past two years, and at least one party to Rulemaking (R.) 04-04-025 has petitioned the Commission to update these QF capacity prices to

[29] The QF prices in Table 1 assume that the renewable generator can meet the performance requirements to earn firm capacity payments. This will be difficult for wind and solar projects. If such technologies pursue QF contracts, they are likely to be paid as-available capacity prices, which are about one-third the levels shown in Table 1.

reflect more up-to-date data on combustion turbine and combined-cycle fixed costs.[30] If these QF capacity prices are updated, the Joint Solar Parties believe that the all-in prices under the QF contracts adopted in D.07-09-040 and the current ten-year MPR price will be basically at similar levels.

2.6.04. The price paid for customer sited solar and wind resources that is offered as a combination of (1) the incentives offered through the California Solar Initiative of Self-Generation Incentive Program and (2) the incentives offered through full retail net metering that provides an ongoing customer incentive for onsite renewable generation?

As the question is phrased, it is very difficult to do an apples-to-apples comparison of the two programs, as they address two different markets: the California Solar Incentive (CSI) was designed, as per SB 1, to provide incentives for "solar energy systems intended primarily to offset part or all of the consumer's own electricity demand," while the tariff/standard contract is a payment for wholesale electricity sold to a utility for distribution and re-sale. Pursuant to D.07-07-027, a customer that participates in the CSI and net metering for its on-site load is not allowed also to sell power to the utility under the AB 1969 framework.

For the purposes of this discussion, there are several important points to make about the CSI program.

- First, while ratepayers contribute funds for the incentive, the primary value of the system comes from reduced purchases from the utility, and the 'price, terms, and conditions' are a function of utility retail tariffs. As retail rates go up, a customer-owned, customer-sited solar system's value to its owner automatically increases. A broad range of retail customers are

[30] Petition of the California Cogeneration Council for Modification of D. 07-09-040, filed in R. 04-04-025 / R. 04-04-003 on March 3, 2008. This petition is still pending.

installing solar, under a wide variety of retail rate schedules. Furthermore, customers on the same retail rate schedule can have very different load profiles. Finally, the IOUs offer different incentive levels because the pace of the CSI program varies between the utilities. As a result, it is difficult to produce a representative example of the effective price paid for power produced under the CSI and net metering.

- Secondly, the CSI incentives are only a small portion of the overall cost of the system.
- The "incentives offered through full retail net metering" are the difference (if any) between a customer's retail rate and the costs that the utility avoids as a result of the customer producing his or her own power behind the meter. The Commission has yet to approve a methodology for performing this analysis, as it has not yet completed work on the cost-effectiveness issues in the CSI rulemaking.
- And finally, the CSI program was specifically designed with market transformation in mind. The CSI program is designed to result in a self-sufficient solar industry that can generate power at parity with retail prices, without any ratepayer subsidy. As the California solar industry grows, the subsidies are reduced and eventually phased out altogether. This is the point—at grid parity—that California's solar market begins, not ends.

On the subject of net metering, the Joint Solar Parties disagree with the premise of the question. Under "full retail net metering," there is no sale of electricity. Net metering is better understood as a crediting arrangement, where a customer-sited, customer-owned solar or wind system feeds excess generation into the grid at one point in time (in the case of solar, typically at peak demand periods of the day), and in return gets a credit that is banked for usage at another point in time (in the case of solar, typically at night, when the solar resource is diminished). The Federal Energy Regulatory Commission takes the same view.[31]

2.7 State anything else the Commission should consider when deciding whether or not to expand the maximum size for facilities eligible to use the tariffs/standard contracts from 1.5 MW to another amount, up to and including 20 MW.

3. Excess Sales: How should electricity purchased pursuant to an excess sales arrangement be counted toward program limits?

3.1 How should an electrical corporation count electricity sold under an excess sales tariff and/or standard contract toward its allocated share of the 250 MW program limit?

Capacity devoted to the service of on-site load should not be counted against a utility's tariff/standard contract enrollment requirement. Some customers who sell under a tariff/standard contract excess sales option may sell just a small portion of their generation system output to a utility. In such cases, it would be inappropriate for a utility to count the full generation system capacity against its program enrollment requirement. Rather, under the excess sales option, only the generation capacity that exceeds on-site peak demand should be counted toward the program limit. For existing onsite load, peak demand can be based on a customer's measured peak demand during the last year. For new load, peak demand will need to be based on a reasonable estimate.

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[31] See *MidAmerican Energy Company*, 94 FERC ¶ 61,340 at 62,263 (2001) ("*MidAmerican*") ("no sale occurs when an individual homeowner or farmer (or similar entity such as a business) installs generation and accounts for its dealings with the utility through the practice of netting.").

3.2 The Commission requires that "standard contracts for full buy/sell and excess sales must ensure that metering is consistent with the CEC RPS accounting requirements in order to accurately track renewable energy." (D.07-07-027, p. 35, footnote 31.) Is anything else necessary to accomplish appropriate tracking of energy, capacity and/or RECs under either a full buy/sell or excess sales transaction for the purposes of measuring capacity toward total program capacity limits?

For a full buy/sell transaction, there must be metering on the renewable generator to measure its full output, as well as metering on the net flow to the utility, so that the full retail load for which power is purchased also can be determined.

3.3 State anything else the Commission should consider in deciding this issue.

4. Third-Party Ownership: What changes, if any, are necessary to permit third party ownership?

4.1 In order to permit the option of partial or full ownership of an eligible facility at the retail customer site by either a utility and/or another entity, please identify changes, if any, that are needed in (a) tariffs/standard contracts or (b) the law. Please be specific.

<u>Partial or full third-party/IOU ownership of a renewable generation facility at a public water and wastewater agency site pursuant to the tariffs required by Public Utilities Code Sec. 399.20(b) and established pursuant to D.07-07-027</u>: Sec. 399.20(b) requires that an electrical generation facility must be owned and operated by a public water or wastewater agency that is a retail customer of an electrical corporation in order to qualify for the tariffs/standard contracts developed pursuant to Sec. 399.20. Therefore, to allow partial or full ownership by either an IOU or another entity under the public water and wastewater tariffs/standard contracts offered by the IOUs pursuant to Sec. 399.20, Sec. 399.20(b) would need to be amended to allow third-party ownership. Presuming this amendment was made, the various tariffs approved in Resolution E-4137 for each IOU would need to be modified to remove the ownership requirements.

Partial or full third-party (non-IOU) ownership of a renewable generation facility at a customer site pursuant to the PG&E and SCE tariffs/standard contracts under the expanded program established in D.07-07-027: The tariffs/standard contracts currently require the owner of the renewable system to also be a retail customer of the IOU and the owner of the system. See, e.g. SCE California Renewable Energy Small Tariff (CREST) Tariff, Applicability and Special Condition 3(c).[32] However, there is no requirement in law for this to be the case. Rather, this requirement arises from the Commission's determination that, as a matter of policy, the expansion of the program to other customers of SCE and PG&E should be done on generally the same terms and conditions as the public water/wastewater tariffs required by AB 1969.[33] Hence, the Commission could change this requirement for the current SCE and PG&E tariffs/standard contracts and authorize ownership of eligible renewable facilities by non-IOU third-parties. In the case of SDG&E, the Commission could authorize non-IOU third-party ownership by parties who are not investor-owned utilities from the onset of the expanded program.

Partial or full IOU ownership of a renewable generation facility at a customer site pursuant to the PG&E and SCE tariffs/standard contracts offered under the expanded program established in D.07-07-027: For solar energy systems specifically, Public Utilities Code Sec. 2775.5 requires the Commission to make specific findings regarding the impacts ownership by the IOUs might have on the solar energy industry prior to authorizing a proposed program.[34] The legislative intent of Sec. 2775.5 is clear regarding the importance of these findings and the Legislature's view that ownership of solar energy systems by IOUs must be carefully reviewed

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[32] PG&E's Small Renewable Generator PPA does not explicitly contain a customer ownership requirement.

[33] See D.07-07-027 p. 46, Conclusion of Law nos. 24 and 25.

[34] See Public Utilities Code Sec. 2775.5 (a) and (b).

by the Commission.[35] The Joint Solar Parties believe the Commission's application process is the best forum for the Commission to obtain the information necessary to make the findings required by Sec. 2775.5. The application process is also consistent with the Commission's current requirement that IOUs file an application for approval of utility ownership of generation facilities occurring outside of competitive solicitations.[36]

4.2 Please make a recommendation regarding whether or not changes should be adopted to permit partial or full ownership by either a utility and/or a third party.

The Joint Solar Parties support third party ownership of renewable energy systems and recommend that the Commission remove its requirement that the owner of a renewable system participating in either the public water/wastewater tariffs/standard contracts or the expanded tariffs/standard contracts also be a retail customer. Deleting this requirement will facilitate further participation in the tariff program by expanding the financing options for renewable energy systems. As seen under the current CSI program, the majority of commercial systems are being installed through third-party power purchase agreement and/or other leasing options. By opening up the tariff/standard contract program to other third-party non-IOU ownership options for the customers, the Commission can substantially increase the use of the program and further the ability of the IOUs to meet their RPS requirements.

The Joint Solar Parties also note that larger renewable facilities may not be connected with on-site load. The Commission's current requirement that a feed-in tariff eligible generator must also be a utility customer places significant restrictions on where small renewable generation may be located. By removing this requirement, the Commission will allow

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[35] See Section 1, Stats 1978, ch. 1102.

[36] See D.07-12-052, p. 212; Ordering Paragraph no. 31.

developers to site renewable generation where it may produce the greatest benefits to the grid.

The Joint Solar Parties recommend that the Commission continue to review IOU-ownership of renewable facilities via the Commission's application process. This requirement is consistent with the Commission's determination in D.07-12-052 that proposals for utility ownership of generation resources taking place outside of a competitive solicitation should be presented for Commission review via the application process. For solar energy systems in particular, the application process is also consistent with the requirements of Public Utilities Code Sec. 2775.5.[37] Lastly, the fundamental policy rationale for establishing a simplified tariff/standard contracts procedure for RPS procurement – eliminating barriers to participation by smaller generators – is simply not applicable to the large IOUs. The IOUs have the ability to develop programs for ownership of renewables and present those program proposals to the Commission for approval.[38]

4.3 If your recommendation is that changes should be adopted to permit partial or full third-party ownership, please be specific, including specific necessary alternate language.

For SCE's CREST Program, the Joint Solar Parties recommend the following changes to SCE's CREST Tariff (redline):

Applicability:

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[37] See Public Utilities Code Sec. 2775.5; see, also, Section 1, Stats 1978, ch. 1102 ("The Legislature further finds and declares that there may be an inherent conflict between a public utility which furnishes gas and electricity on the one hand and develops solar energy on the other hand… It is, therefore, the intent of the Legislature that the Public Utilities Commission be given a clear and explicit mandate to regulate the involvement of privately owned public utilities in solar energy development, and to ensure that the solar energy industry develops in a manner which is competitive and free from the potential dominance of regulated electrical and gas corporations.").

[38] See, e.g., Application 08-03-015, Application of Southern California Edison Company (U 338-E) for Authority to Implement and Recover in Rates the Cost of its Proposed Solar Photovoltaic (PV) Program, filed March 27, 2008.

This Schedule is optional for customers or other entities who do not meet the definition of an Eligible Public Water Agency or Wastewater Agency, as defined in the Special Condition section of this Schedule, who own, ~~and~~ operate, or host an Eligible Renewable Generating Facility, as defined in the Special Condition section of this Schedule, with a total effective generation capacity of not more than ~~1.5~~ 20 megawatts (MW).

Special Condition 3(c):

Eligible Renewable Generating Facility – A generating facility that is owned, ~~and~~ operated, or hosted by a customer or other entities who is not an Eligible Public Water Agency or an Eligible Wastewater Agency which receives distribution service from SCE, and where the Eligible Renewable Generating Facility meets all of the following criteria:
(1) Has an effective capacity of not more than ~~1.5~~ 20 MW and is located ~~on the premises owned or under the control of the customer~~ within the service territory of SCE.
(2) Is interconnected and operates in parallel with the electric transmission and distribution grid.
(3) Is strategically located and interconnected to the electric transmission system in a manner that optimizes the deliverability of electricity generated at the facility to load centers.
(4) Is an eligible renewable energy resource, as defined in Public Utilities Code Section 399.12.

For PG&E's Small Renewable Generator PPA Program, the Joint Solar Parties recommend the following changes to PG&E's Small Renewable Generator PPA (redline):

APPLICABILITY: This Schedule is optional for customers or other entities who own, operate, or host an Eligible Renewable Energy Resource that meets the definition of an Eligible Renewable Energy Resource as defined in the Special Conditions section of this Schedule, with a total effective generation capacity of not more than ~~1.5~~ 20 megawatts and is located within the service territory of PG&E.

For SDG&E, a tariff meeting the requirements of D.07-07-027 and the determinations in this phase of the proceeding would need to be developed.

4.4 State anything else the Commission should consider when deciding this issue.

5. Other Modifications Please state anything else the Commission should consider before completing this implementation. Please include recommended action, if and as necessary, to complete this implementation. Please include necessary facts and law that must be considered. Please be specific.

5.1 The MPR for AB 1969 contracts should reflect the locational benefits of small, wholesale distributed generation projects.

The March 2008 comments of GreenVolts *et al* emphasized that there is an underserved renewables market segment where small renewable generators supplying wholesale power can be sited on utility distribution systems near significant loads.[39] The renewable, wholesale distributed generation (WDG)[40] supplied by projects like GreenVolts' promises to provide ratepayers with significant locational benefits, compared to large renewable projects that typically must be sited in remote locations where large tracts of land are available. The locational benefits of WDG include: (i) increased capacity of distribution transformers at the generation site and at the substation level during peak periods, which reduces line losses and increases transformer life; (ii) avoided distribution system upgrades when DG is located on areas of the distribution grid (or feeders) that are capacity constrained;(iii) avoided transmission system upgrades that are required to access remote renewable resources that are located far from load; (iv) meeting local resource adequacy needs; (v) reducing congestion costs; and (vi) reducing transmission and distribution line losses.

Importantly, these benefits are not reflected in the current MPR, which is the "brown power" pricing benchmark applicable to small renewable generation projects developed under AB 1969. To date, the MPR has been designed, like the larger RPS program, with a focus on large generation projects that supply many tens or hundreds of megawatts of wholesale power delivered into the bulk transmission system. The MPR today is calculated as the cost of a 500 MW gas-fired combined-cycle power plant sited in California and delivering power to the load center on the CAISO's high-voltage transmission system.

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[39] See Pre-workshop Comments of GreenVolts, Cleantech America, and Community Environmental Council on the 2008 Market Price Referent, Rulemaking 06-02-012, filed March 6, 2008.

[40] "Wholesale distributed generation" (WDG) projects are significantly distinguished from traditional "distributed generation" (DG), which generally refers to small, retail generation projects sized to serve a specific on-site load, with power flowing onto the utility distribution system only to the limited extent that on-site generation happens to exceed on-site load.

The use of a feed-in tariff structure for small, renewable WDG up to 20 MW in size will require the Commission to re-examine and to modify the pricing within the tariff/standard contract that is applicable to WDG projects. In particular, as discussed further in these comments, the Commission will need to include in the pricing for the tariff/standard contracts the real and quantifiable benefits that ratepayers derive from the favorable location of this new renewable generation, as enumerated above. The Commission should not simply assume that the pricing of power from small renewable generators should use the same "brown power" benchmark as large RPS projects interconnected to the CAISO's high voltage transmission grid. By interconnecting on the distribution system close to loads, renewable WDG can avoid additional costs incurred in moving power from the RPS MPR's 500 MW combined-cycle plant to where WDG projects can be located on the distribution system close to loads.

The pricing applicable to WDG projects will need to be modified in several steps to include the locational benefits of WDG projects. The Joint Solar Parties outline below how and why the MPR should be adjusted when applied to WDG projects.

MRTU-based Transmission Losses and Congestion. Today, the CAISO uses Generation Meter Multipliers (GMMs) to assess the transmission line loss impacts of each generator on the CAISO transmission grid. A generator's GMM is a measure of its contribution to system average transmission line losses in delivering its power output to a virtual load center. The MPR price is adjusted by the system average GMM, to reflect the delivery of the benchmark CCGT's power to the CAISO load center.[41] Typical RPS contracts pay renewable generators for their generation adjusted by their site-specific GMM, again to reflect delivery to the CAISO load

[41] Currently, the system average GMM used in the MPR model is the simple average of the GMMs on the CAISO grid. A pending issue in R. 06-02-012 is whether the 2008 MPR calculation should be revised to use the average GMM weighted by the output of each generator, i.e. the system average loss factor for the CAISO grid.

center.

With respect to intra-zonal congestion, such costs are not reflected in prices on the CAISO grid today. Instead, the CAISO relieves such congestion through out-of-market means.

The CAISO's new Market Re-design and Technology Update (MRTU) program will implement a new system of Locational Marginal Pricing (LMP). LMP will provide new data on transmission line loss and congestion costs at thousands of nodes on the CAISO grid. LMP nodal prices will include line loss and congestion components of the market price at each node. The MRTU loss component will reflect the marginal losses at that node; this represents a significant change from the GMM methodology, which uses losses scaled to system average losses. LMP also will provide an explicit valuation of intra-zonal congestion costs at each node. Further, the CAISO will provide aggregated losses and congestion costs across all of the nodes on its system and across each utility's service territory. Thus, for AB 1969 projects, it will be possible to determine an MPR adjusted to fit the specific location of each project, reflecting a project's site-specific annual losses and congestion costs under MRTU compared to the system- or utility-average values for these costs.

MRTU is not expected to "go live" until October 2008 at the earliest. Time will be required to ensure that MRTU is working as planned and to accumulate data on site-specific losses and congestion costs under MRTU. However, the Commission should work toward incorporating MRTU line loss and congestion costs into the MPR and into MPR-based prices under AB 1969, in conjunction with either the 2009 or 2010 MPRs.

Distribution Losses. Small generators located on the distribution system can avoid the distribution line losses specified in the utilities' Wholesale Distribution Access Tariffs (WDATs). The Commission has long recognized this fact with respect to small QFs located on the distribution system.[42] In the QF program, the Commission generally has looked to the utilities' WDATs as the source for avoided distribution losses.[43] **Table 2** below lists the existing WDAT energy loss factors of the three major California IOUs. The MPR applicable to renewable WDG interconnected to the IOUs' distribution systems should be increased by one divided by one minus the distribution loss factors in **Table 2**, as given by the following formula to reflect the value of these avoided distribution losses:

WDG Distribution Loss Factor = 1 / (1 – WDAT Energy Loss Factor)

Table 2: *Utility WDAT Energy Loss Factors*

Utility	Distribution Voltage	WDAT Energy Loss Factors
PG&E	Primary	1.25%
	Secondary	3.62%
SCE	Subtransmission	1.12%
	Primary	3.73%
SDG&E	All voltages	0%

Sources: PG&E WDAT tariff, D.01-01-007for SCE and SDG&E.

For solar projects that produce much of their energy in peak periods, the use of these average distribution loss factors will be a conservative adjustment, as line losses are significantly above the average in peak demand periods when line loadings are the highest.

Avoided Investment-related T&D Costs. Small renewable generators can allow the utilities to avoid investments in transmission and distribution (T&D) facilities. These avoided T&D costs are real and can be quantified using Commission-approved methodologies. The Commission's adopted E3 model for the avoided costs associated with energy efficiency programs includes a time-dependent, hourly valuation of avoided investment-

[42] D.82-12-120, D.84-03-092, and D.87-12-066.

[43] For example, in the Commission's most recent review of QF line losses – D.01-01-007 – the Commission adopted Southern California Edison's and San Diego Gas & Electric's WDAT distribution loss factors as the measure of the distribution line losses avoided by QFs that deliver into the distribution systems of these utilities.

related T&D costs.[44] This model can be used to value the avoided T&D costs from a WDG project, and these costs should be added to the MPR applicable to an AB 1969 project.

The Joint Solar Parties are aware that the utilities have been reluctant to recognize that generators avoid T&D costs unless a generator is located in an area where specific costs can be avoided.[45] The Joint Solar Parties agree with the March 2008 comments of GreenVolts *et al* concerning the best way forward on this issue: working cooperatively with the IOUs' T&D planners to identify sites that offer greater T&D benefits than the average avoided T&D values produced by the E3 model. Developers of solar WDG would welcome the opportunity to cooperate with the utilities to locate projects at sites on the utility distribution systems where the solar peaking generation provides the greatest benefits for ratepayers, in terms of serving peak period demands and avoiding T&D investments.[46] Projects sited in this cooperative way would receive an adder to their MPR value equal to the expected avoided T&D costs calculated by the adopted E3 model.[47] The avoided T&D costs in the E3 model are average values for each IOU division or planning region. As a result, if renewable WDG is sited in locations with higher-than-average incremental T&D costs, ratepayers would be assured that they have received more-

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[44] The Commission adopted the E3 model of avoided costs associated with energy efficiency programs in D.05-04-024.

[45] When the Commission reviewed the E3 model in 2004 - 2005, the utilities opposed the inclusion of avoided T&D costs in the model, arguing that energy efficiency resources avoid T&D costs only in certain specific, case-by-case circumstances, such as on a rapidly-growing distribution circuit where an upgrade is needed in the near future. The Commission rejected this position in D.05-04-024, finding that "while a case-by-case analysis should be applied to determine payments related to specific projects for long-term conservation measures it is appropriate to credit programs with T&D avoided costs for program evaluation purposes." See D.05-04-024 at 35-36.

[46] Obviously, if a project's generating capacity exceeds the capacity of the local distribution system, then the system will need to be upgraded, and the project will incur, rather than avoid, distribution costs.

[47] The Joint Solar Parties recognize there are technical issues which need to be resolved as part of establishing this cooperative process including arriving at technical standards for system sizes for any particular distribution line or circuit. A workshop would be the best forum to discuss these technical issues and work out reasonable solutions in a cooperative fashion.

than-full value if the pricing under a tariff/standard contract for such projects includes average avoided T&D costs for that area as an adder to the MPR, as calculated by the E3 model. The comments of GreenVolts *et al* calculated such an adder for each IOU division or planning region included in the E3 model, for both a baseload (7x24) output profile and for a representative solar photovoltaic (PV) output profile from a south-facing flat-plate PV system at a 38.5 degree tilt located in Sacramento, California. These avoided T&D adders, including separate transmission and distribution components, are reproduced from the March 2008 GreenVolts *et al* filing and are presented in **Attachment B**.[48]

Actual experience with solar DG developed under the Commission's Self Generation Incentive Program (SGIP) is beginning to show that distributed PV systems can reduce peak demands on utility distribution systems. The August 2007 evaluation report on the SGIP program shows that, in the summer of 2006, installed PV systems reduced distribution line loadings on peak summer afternoons by 42% to 56% of the PV systems' installed capacity.[49] The evaluation consultant, Itron, concluded that "SGIP technologies are seen to provide the potential for significant reduction in peak loading of the distribution system."[50] Itron's report notes a number of the barriers that have prevented SGIP projects from producing an even greater level of capital-related savings on the distribution system:

> In addition to limited penetration of SGIP facilities within the distribution system, a number of other factors contribute to a lack of distribution capital savings. One of these is that the SGIP generators operate independently of the distribution system.

[48] The E3 model calculates that the solar generation profile produces about 75% of the avoided T&D benefits of the baseload profile, because PV output is high during the peak afternoon hours when peaks occur on the distribution system.

[49] Some PV technologies track the sun, and thus will sustain higher output than the flat-plate PV profile used in the table over the course of a peak summer afternoon.

[50] Itron, "CPUC Self-Generation Incentive Program – Sixth Year Impact Evaluation Report" (August 30, 2007), at Table 4-1 and pages 1-10 to 1-14.

> Therefore, the SGIP owner does not know when the distribution peak is, nor do they have any incentive to operate during the peak even if they did know. In fact, the current SGIP rules prohibit an additional incentive to operate during the local capacity peak. Similarly, the distribution utility planners do not necessarily know which SGIP generators are being served by overloaded equipment, likely because the penetration of SGIP generators is not currently high enough to warrant close attention for capacity planning at the distribution level. In addition, SGIP owners choose where to install their systems, not the utility; therefore, they are not a concentrated number of installations in a single area of need that could provide significant load relief on a particular overloaded feeder or substation.[51]

The cooperative effort first proposed by GreenVolts *et al* this spring, and supported in these comments, can address all of these important concerns.

To encourage the development of renewable WDG projects, the Joint Solar Parties ask the Commission to direct the utilities to publish, by the end of 2008, a list of the distribution substations on their systems where WDG would avoid T&D costs at least as high as those specified in the E3 model. This report essentially would be a distribution-level version of the Transmission Ranking Cost Report that the utilities publish as part of their RPS solicitations to indicate the availability and cost of bulk transmission on their systems.

5.2 Intermittent renewable generators that participate in the CAISO's PIRP program should not bear the costs of imbalances.

The standard contracts that the utilities have filed pursuant to AB 1969 and D.07-07-027 generally require the small generator to bear the costs of imbalances between their scheduled and actual generation, although the utility serves as the project's Schedule Coordinator (SC).[52] Managing imbalances can represent a significant administrative burden and cost risk for

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[51] Id. at 5-28.

[52] For example, see Section 11.2.1 of the standard contract that is part of PG&E's E-PWF tariff.

intermittent renewables that do not control the availability of their wind or solar resource. To mitigate this risk, the CAISO has a Participating Intermittent Renewables Program (PIRP) that allows intermittent renewables to aggregate their imbalances over an entire month, provided the project schedules its output using a CAISO-sponsored state-of-the-art forecast of renewable output. The Joint Solar Parties suggest that the utility and the generators should share the burdens of minimizing imbalance costs: if the generator (1) participates in the PIRP program, (2) provides the utility, as its SC, with timely information on its availability, and (3) provides the utility with remote access to its metered output, then the utility should bear the risks of imbalances. Imbalance costs can be both positive and negative, and over many small generators and with the mitigation provided by PIRP, the aggregate cost to the utility should be very small. The standard contracts should be revised to provide for this sharing of imbalance responsibility.

II. CONCLUSION

The Joint Solar Parties appreciate the opportunity to provide these opening comments addressing issues regarding tariff and standard contract implementation for RPS generators contained in Attachment A of the Ruling. As discussed in these opening comments, the Joint Solar Parties believe small renewable generation can contribute meaningfully to RPS procurement if tariff/standard contracts are put in place for each IOU which addresses the needs of small generators for a consistent, simple, and transparent contract process that also recognizes the benefits wholesale distributed generation can bring to the grid.

Respectfully submitted this July 9, 2008 at San Francisco, California.

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3326/003/X101032.v2

Verification – The Vote Solar Initiative

I am an employee of the Vote Solar Initiative, and am authorized to make this verification on its behalf. The statements in the foregoing document are true of my own knowledge, except as to matters which are therein stated on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the forgoing is true and correct.

Executed on July 3, 2008, at San Francisco, California.

Adam Browning, Executive Director, The Vote Solar Initiative

Verification – Recurrent Energy, Inc.

I am an employee of Recurrent Energy, Inc., and am authorized to make this verification on its behalf. The statements in the foregoing document are true of my own knowledge, except as to matters which are therein stated on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the forgoing is true and correct.

Executed on July 3, 2008 in San Francisco, California.

Arno Harris
CEO and President
Recurrent Energy

ATTACHMENT A

Table 1

Comparison of 2007 MPR and QF Pricing per D. 07-09-040

2007 MPR -- All-in CCGT Costs

10-year contract starting in 2009	Profile	SDG&E *$/MWh*	PG&E *$/MWh*	SCE *$/MWh*
	Baseload	93.1	93.1	93.2
	Solar	109.2	105.6	127.5

QF Avoided Cost -- SRAC Energy & Firm Capacity

	Profile	SDG&E *$/MWh*	PG&E *$/MWh*	SCE *$/MWh*
SRAC Energy	Baseload	71.2	71.1	71.1
Levelized 2009 - 18	Solar	80.3	78.5	80.4
Firm Capacity	Baseload	10.7	10.6	10.5
10-year contract	Solar	27.6	26.4	26.6
Total	Baseload	81.9	81.7	81.6
	Solar	107.9	104.8	107.1
% Difference	*Baseload*	*-12%*	*-12%*	*-12%*
QF vs. MPR	*Solar*	*-1%*	*-1%*	*-16%*

ATTACHMENT B

E3 Model T&D Values (Levelized 20-year in 2008$)

		Transmission & Distribution				Transmission-only				Distribution-only			
Utility	Division	Baseload Profile		Solar Profile		Baseload Profile		Solar Profile		Baseload Profile		Solar Profile	
		$/kW-year	$/MWh	$/kW-year	$/MWh	$/kW-year	$/MWh	$/kW-year	$/MWh	$/kW-year	$/MWh	$/kW-year	$/MWh
PG&E	Central Coast	$46.07	$5.26	$35.70	$24.60	$1.55	$0.18	$1.20	$0.83	$44.51	$5.08	$34.50	$23.77
	De Anza	$58.67	$6.70	$46.95	$32.35	$1.55	$0.18	$1.24	$0.86	$57.11	$6.52	$45.71	$31.49
	Diablo	$55.62	$6.35	$44.51	$30.67	$1.55	$0.18	$1.24	$0.86	$54.06	$6.17	$43.27	$29.81
	East Bay	$11.57	$1.32	$8.97	$6.18	$1.55	$0.18	$1.20	$0.83	$10.02	$1.14	$7.77	$5.35
	Fresno	$48.24	$5.51	$37.08	$25.55	$1.55	$0.18	$1.19	$0.82	$46.68	$5.33	$35.89	$24.72
	Kern	$30.87	$3.52	$23.73	$16.35	$1.55	$0.18	$1.19	$0.82	$29.32	$3.35	$22.54	$15.53
	Los Padres	$46.82	$5.34	$37.47	$25.81	$1.55	$0.18	$1.24	$0.86	$45.26	$5.17	$36.23	$24.96
	Mission	$70.36	$8.03	$54.53	$37.57	$1.55	$0.18	$1.20	$0.83	$68.80	$7.85	$53.32	$36.74
	North Bay	$47.46	$5.42	$36.78	$25.34	$1.55	$0.18	$1.21	$0.83	$45.90	$5.24	$35.57	$24.51
	North Coast	$64.43	$7.35	$40.41	$27.84	$1.55	$0.18	$0.97	$0.67	$62.87	$7.18	$39.43	$27.17
	North Valley	$80.30	$9.17	$63.33	$43.63	$1.55	$0.18	$1.23	$0.84	$78.74	$8.99	$62.10	$42.78
	Peninsula	$20.90	$2.39	$16.19	$11.16	$1.55	$0.18	$1.20	$0.83	$19.34	$2.21	$14.99	$10.33
	Sacramento	$60.93	$6.96	$48.05	$33.11	$1.55	$0.18	$1.23	$0.84	$59.37	$6.78	$46.83	$32.26
	San Francisco	$16.89	$1.93	$13.09	$9.02	$1.55	$0.18	$1.20	$0.83	$15.34	$1.75	$11.89	$8.19
	San Jose	$44.65	$5.10	$35.74	$24.62	$1.55	$0.18	$1.24	$0.86	$43.10	$4.92	$34.49	$23.76
	Sierra	$66.84	$7.63	$52.71	$36.32	$1.55	$0.18	$1.23	$0.84	$65.29	$7.45	$51.49	$35.47
	Stockton	$69.90	$7.98	$55.94	$38.54	$1.55	$0.18	$1.24	$0.86	$68.34	$7.80	$54.69	$37.68
	Yosemite	$42.73	$4.88	$34.20	$23.56	$1.55	$0.18	$1.24	$0.86	$41.18	$4.70	$32.96	$22.70
SCE	Dominguez Hills	$45.91	$5.24	$32.93	$22.69	$26.09	$2.98	$18.71	$12.89	$19.82	$2.26	$14.21	$9.79
	Foothills	$59.90	$6.84	$42.96	$29.59	$26.09	$2.98	$18.71	$12.89	$33.80	$3.86	$24.24	$16.70
	Santa Ana	$55.19	$6.30	$39.58	$27.27	$26.09	$2.98	$18.71	$12.89	$29.10	$3.32	$20.87	$14.38
	SCE Rural	$72.95	$8.33	$53.87	$37.11	$26.09	$2.98	$19.27	$13.27	$46.86	$5.35	$34.60	$23.84
	Ventura	$57.57	$6.57	$41.29	$28.45	$26.09	$2.98	$18.71	$12.89	$31.48	$3.59	$22.58	$15.56
SDG&E	SDG&E	$114.15	$13.03	$84.35	$58.11	$13.84	$1.58	$10.23	$7.05	$100.31	$11.45	$74.12	$51.07

Note: assumes 2008 - 2027 project lifespan, 2.5% inflation, 8.93% discount rate, and 2008 $.

CERTIFICATE OF SERVICE

I, Lisa Vieland, certify that I have on this 9th day of July 2008 caused a copy of the foregoing

OPENING COMMENTS OF THE VOTE SOLAR INITIATIVE AND RECURRENT ENERGY, INC. ON THE ISSUES REGARDING PHASE 2 OF TARIFF AND STANDARD CONTRACT IMPLEMENTATION FOR RPS GENERATORS

to be served on all known parties to R.06-05-027 listed on the most recently updated service list available on the California Public Utilities Commission website, via email to those listed with email and via U.S. mail to those without email service. I also caused courtesy copies to be hand delivered as follows:

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I declare under penalty of perjury that the foregoing is true and correct.

Executed this 9th day of July 2008 at San Francisco, California.

/s/ Lisa Vieland
Lisa Vieland

3326/003/X100990.v2

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