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 11-05-005 (Filed May 5, 2011)

COMMENTS OF THE INDEPENDENT ENERGY PRODUCERS ASSOCIATION ON THE RPS PROCUREMENT PLANS

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Dated: July 2, 2014

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The Independent Energy Producers Association (IEP) offers its comments on the Renewables Portfolio Standard (RPS) procurement plans of Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE), as provided in the "Assigned Commissioner's Ruling Identifying Issues and Schedule of Review for 2014 Renewables Portfolio Standard Procurement Plans," dated March 26, 2014, as modified by the Administrative Law Judge's revised schedule attached to her email of April 16, 2014. After presenting a few general comments, IEP will discuss certain issues raised in each utility's draft Renewable Portfolio Standard (RPS) procurement plan and related materials. IEP will focus its comments on new or changed provisions and will not re-argue issues that the Commission has already resolved.

I. GENERAL COMMENTS

Assembly Bill (AB) 327 made a significant change to California's approach to the RPS and to RPS procurement. Before AB 327 was enacted, Public Utilities Code section 399.15(b)(3) stated that the Commission "shall not require the procurement of eligible renewable resources in excess of" the percentages established in the statute, including 33% in 2020. AB

327 reversed this provision to empower the Commission to "require the procurement of eligible renewable energy resources in excess of the quantities specified" in the statute. Thus, where the RPS statute previously set a *ceiling* of 33% on the Commission's ability to require procurement of renewable energy, AB 327 established a *floo*r on RPS procurement at 33% of annual retail sales.

The enactment of AB 327 was a clear indication that the Legislature and the Governor no longer considered achievement of the 33% standard as the fulfillment of the RPS program. This shift has significant implications for RPS procurement policy. The Legislature and the Governor are clearly looking beyond 2020 and the existing 33% procurement obligation to a time when greater levels of renewable energy will be part of the state's resource base, and the Commission is now authorized to require greater renewables procurement from the investor-owned utilities. The RPS procurement plans, however, continue to be focused on meeting the minimum RPS obligation, 33% by 2020. The plans fail to address any proposals for procuring more than the minimum obligation, and do not describe the circumstances under which the utilities will voluntarily choose to procure greater levels of renewable energy. The focus on the minimum obligation also colors the utilities' approach to key operational issues. IEP addresses these issues in more detail below.

A. RPS Procurement Above the 33% Floor

The utilities' 2014 RPS procurement plans are constructed to meet the 33% RPS obligation for 2020, and the plans continue to assume that the 33% RPS obligation is a ceiling, rather than a floor, on RPS-eligible deliveries. The 2014 plans lack a clear discussion of under what circumstances the utilities would purchase greater levels of renewable energy and how the utilities are analyzing this option.[1] Moreover, in instances when renewable generators may produce "excess deliveries," the utilities propose to pay less than the contract price. IEP questions the assumption that the first MWh delivery of RPS-eligible energy exceeding some arbitrary threshold is less valuable from an energy and environmental perspective than the last MWh delivered below the same threshold.

B. Curtailment

Curtailment provisions have become increasingly important as forecasted supply and demand patterns have changed significantly over the past five years, as illustrated by the "duck chart" developed by the California Independent System Operator Corporation (CAISO); as the CAISO's markets experience occasional negative prices as a result of supply and demand imbalances; and as increased construction of transmission facilities requires interruptions of transmission service. The utilities have taken different approaches to address this issue, including proposing various curtailment provisions. From IEP's perspective, the key considerations for evaluating proposed curtailment provisions are (1) whether the contract is financeable with the curtailment provision and (2) whether the risk of curtailment is clearly bounded so that rational investment decisions can be made.

IEP recognizes that a single curtailment provision will not meet the needs of the various renewable energy providers. IEP thinks it is useful to have a variety of curtailment options as part of the pro forma power purchase agreement (PPA), to reduce negotiation time and to allow a wide variety of projects and technologies to participate in the Request for Offers (RFOs). For example, SCE has presented four options for the treatment of curtailment in its PPA. Assuming each of these options is financeable and bounded, IEP recommends this type of

[1] Discussions of each utility's Voluntary Margin of Over-Procurement address a different issue. VMOP refers to the amount of excess renewable energy a utility will purchase to account for contract failure and underperformance, and to ensure that it will achieve the 33% goal by 2020.

optionality, and encourages the utilities to fine-tune curtailment provisions based on practical experience over time.

C. Integration Cost Adders

The utilities do not propose a non-zero integration cost adder because earlier Commission decisions prohibited using integration cost adders until they have been explored in a public process. The utilities will file additional comments on integration costs on July 2, 2014, and IEP will respond to those comments at the appropriate time. IEP urges the Commission to move expeditiously on this matter. IEP seeks rational, empirically based integration cost adders. IEP recognizes, however, that these factors will change over time. Accordingly, it may not be critical now to await the completion of studies designed to produce excessive precision about integration cost adders. It may be reasonable for the present purposes to derive approximations of integration cost factors for use in the near term, recognizing that the values of the adders and methodological approaches will change as new information becomes available over time.

II. COMMENTS ON SCE'S PROCUREMENT PLAN

A. Curtailment

SCE's pro forma PPA provides four options for curtailment:

1. 50 hours of unpaid curtailment. Curtailments in excess of 50 hours are compensated, including curtailments during on-peak hours, but are subject to repayment after the end of the contract. The repayment obligation is to provide twice the curtailed quantity of energy at half the contract price for up to two years;[2]

2. 50 hours of unpaid curtailment with no repayment obligation;

3. no unpaid curtailments but with a repayment obligation; and

4. no unpaid curtailments with no repayment obligation.

[2] SCE's Pro Forma PPA, §§ 1.05(b), 1.06(b). However, SCE will no longer compensate sellers for the loss of the Federal Production Tax Credit for curtailed generation. (See deleted § 4.01(d).)

IEP supports SCE's approach generally. However, the details of SCE's proposal ought to be more fully developed in its RPS procurement plan and not left to the actual RFO. For example, the plan is silent about how SCE will evaluate bids based on each of these options in the RFO, and this information should be made more transparent to bidders as early as possible for their consideration before bids are submitted. On the other hand, SCE's curtailment structure provides adequate predictability of revenues, even during times of curtailment, and the repayment obligation appears to be manageable. In addition, SCE's pro forma provides some flexibility about the number of hours that are curtailed with no compensation.

B. <u>The Treatment of Excess Deliveries</u>

As a general matter, SCE's pro forma PPA includes provisions designed to discourage the production of energy in excess of the expected quantities. It's not clear, however, that SCE's proposal to impose additional constraints on RPS-eligible energy production are warranted or needed. IEP's understanding is that site controllers employed by large-scale renewable facilities are designed to reduce over-deliveries to comply with the limitations prescribed by the facility's Interconnection Agreement. Those site controllers and stricter attention to the capacity proposed for a project should be sufficient to prevent any operational problems created by over-deliveries. While IEP understands that utilities prefer predictable quantities of energy for scheduling purposes, this preference may be unfair to the seller-generator. Furthermore, SCE's proposal may discriminate among various types of renewable resources based on their relation to the electric grid. IEP notes that no restrictions are placed on generation from rooftop solar installations and other behind-the-meter renewable generators, even though these installations are contributing to the problems raised by the "duck chart" and negative energy prices. In fact, under the Net Energy Metering program, these behind-the meter installations may be financially rewarded for generating more energy than needed to meet the associated demand.

1. Excess Deliveries Within a Scheduling Interval

SCE proposes not to pay the seller during any settlement interval for energy deliveries in excess of 100% of the contract capacity;[3] previously SCE had paid for deliveries up to 110% of contract capacity.[4] SCE acknowledges that "there are reasonable technical explanations for why a generating facility may on rare occasions produce output in excess of contract capacity," but SCE argues that any payment for excess deliveries would constitute a "windfall" for the seller.

IEP has concerns about this proposal for a number of reasons. First, public policy, as articulated in AB 327, is geared to promote increased deliveries of energy from RPS-eligible resources. SCE's proposal is particularly problematic and troublesome because many of SCE's RPS contracts are with intermittent resources that cannot predict their energy generation with absolute precision. Second, SCE's proposal effectively produces a windfall for SCE on those occasions when a generator delivers in excess of contract capacity. In exchange for paying nothing (under SCE's proposal), SCE would in most instances receive a Category 1 bundled product composed of energy and a Renewable Energy Credit (REC), both of which have value (except energy during times of negative prices). In reality, the "excess" energy can and should be used to meet customers' needs, and the REC can be used to meet the utility's RPS obligations, banked for future compliance, or sold in the market either in a bundle with the energy or as an unbundled product. If SCE is excused from paying the contract price for excess deliveries, at a

[3] SCE's Pro Forma PPA, § 1.06(c)(i).
[4] SCE's 2014 Written Plan, p. 54.

minimum the generator should receive the market price for the bundled energy and RECs associated with the excess deliveries.

2. Excess Annual Deliveries

Similarly, SCE proposes to pay sellers only the CAISO revenues (net of costs) for energy for *annual* production in excess of 115% of expected annual net energy production.[5] SCE previously paid the seller 75% of the contract price for these excess deliveries.[6] While CAISO revenues (net of costs) may provide some compensation for the energy, SCE's proposal in effect gives RECs to SCE for free. Moreover, because the term of measurement of the excess is a year, generators will not know until near the end of the year whether they will receive full compensation for energy deliveries or something less, and sellers may have little ability at that point to alter their operations to avoid excess annual deliveries. Wind and hydroelectric resources are particularly susceptible to annual variations, but other renewable technologies may also be penalized by this provision. If a planned outage goes well and the unit can resume operation earlier than expected, for example, the unit could be punished for its efficiency by having its energy price reduced to zero and its REC seized. Again, the seller should be guaranteed payment of at least the market price of bundled energy and a REC for its annual deliveries in excess of contract capacity.

IEP opposes SCE's proposed approach for the treatment and compensation of excess annual energy deliveries. This approach fails to compensate for (and therefore incent) the maximum level of energy production from RPS-eligible resources, and it appears to provide a significant commercial windfall for SCE. IEP recommends that the Commission should maintain the current provision approved by the Commission for SCE's 2013 RPS procurement

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[5] SCE's Pro Forma PPA, § 1.06(c)(ii).
[6] SCE's 2014 Written Plan, pp. 54-55.

plan. As an alternative, "excess" energy should be measured over a period of two or three years, so the generators have a chance to balance below-average years and above-average years. Another option would be to allow generators to sell any "excess" energy and RECs to another buyer (perhaps subject to a right of first refusal by SCE), and to require SCE, as the Scheduling Coordinator, to facilitate such sales.

C. SCE's Review of Design Changes

In section 3.11(d) of the pro forma PPA, SCE has added a provision that gives it "sole discretion" to approve or reject material design changes proposed by the seller. While it seems reasonable to allow SCE, as the buyer, to review material changes to ensure that the changes do not affect the seller's ability to perform under the PPA, giving SCE an absolute veto over all material design changes is unreasonable.

IEP suggests two modifications to this provision. First, this provision should be modified to read, "SCE shall retain the right to review such proposed changes and accept or reject such changes in its ~~sole~~ discretion, which shall be reasonably exercised." This revision would at least give the seller some ability to challenge SCE's unreasonable decisions about design changes. Second, SCE should be required to identify and justify the types of design changes that affect its interests under the PPA. This provision is currently written far too broadly and gives SCE far too much authority over the design of the project.

D. Provisions Related to Tax Incentives

SCE removed references to the Investment Tax Credit (ITC) because it would require a project to be begin commercial operation by December 31, 2016, and SCE believes few projects could meet that target.[7] References to the Production Tax Credit (PTC) were presumably removed because the credit expired at the end of 2013. Removal of references to

[7] SCE's Procurement Plan, p. 51.

these tax incentives may prove to be short-sighted. The PTC has lapsed several times and been extended five times, and there currently is a move in Congress to extend the credit again. Similarly, the eligibility date for the ITC may yet be extended beyond 2016.

Rather than adopting the new approach proposed by SCE, IEP recommends retaining the provisions incorporated in the 2013 pro forma PPA. Preserving the status quo on this issue may prove to be easier than forcing SCE and Sellers to negotiate new provisions if the incentives are extended again. If the ITC is not extended and the PTC is not extended, then the values for the ITC and PTC will be zero and will have no effect on the balance of the PPA.

III. COMMENTS ON PG&E'S PROCUREMENT PLAN

PG&E proposes relatively few changes to its 2014 RPS procurement plan and pro forma PPA, compared to the corresponding documents for 2013. IEP accordingly comments on just a few items.

A. Delays in Completion of Transmission Upgrades

PG&E recognizes that projects may experience delays in the completion of transmission upgrades needed for Full Capacity Deliverability Status (FCDS) that will push the FCDS date beyond the Initial Energy Delivery Date (IEDD), which could trigger an Event of Default. PG&E includes two proposals that address this type of delay.

1. Temporary Energy-Only Status

First, PG&E will allow projects to offer resources whose FCDS date is later than the IEDD. PG&E will evaluate these bids by treating the project as an energy-only project from the Commercial Operation Date until FCDS is achieved, for up to two years.[8]

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[8] PG&E's RPS Procurement Plan, p. 72.

2. Liquidated Damages as an Alternative to Default

Second, PG&E proposes to allow projects that find themselves in this position to pay liquidated damages for the delay, rather than facing an Event of Default that could result in termination of the PPA.[9]

IEP supports PG&E's attempt to provide an alternative to default for projects that encounter unavoidable delay.

B. Curtailment

PG&E proposes to eliminate any hourly limits on curtailments but will pay the seller for energy that is deemed delivered during the curtailment period.[10] The price paid for deemed delivered energy is left blank in the pro forma PPA, and it appears that either the seller will specify the price it is willing to take when it is curtailed or the parties will negotiate a price. If the price for deemed delivered energy is negotiated rather than specified by the seller, IEP would be concerned if the payment for RPS-eligible delivery is significantly less than the contract price. The pro forma PPA gives PG&E broad discretion to curtail generators within the plant's operational bounds. PG&E's PPA does not specify a limit on the number of curtailments, and accordingly the level of compensation for curtailments becomes more important. As noted elsewhere, IEP supports a range of curtailment options for Buyers and Sellers to consider when contracting, such as those proposed by SCE. IEP recommends that optionality of the sort proposed by SCE should be included in PG&E's RPS procurement plan to provide a measure of certainty about the price for curtailed energy from RPS-eligible resources.

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[9] PG&E's RPS Procurement Plan, pp. 43-44.
[10] PG&E's Pro Forma PPA, § 3.1(o).

C. WREGIS

The pro forma agreement is tightly tied to the certification and registration function played by the Western Renewable Energy Generation Information System (WREGIS). The role of WREGIS in the tracking of renewable energy, however, has become somewhat more controversial in recent years, and there is no guarantee that WREGIS will continue to play its current role for the duration of a 20-year PPA. The potential for a change in the role of WREGIS leads to several recommendations.

First, IEP recommends implementation of a more stable approach from a contracting perspective. In this regard, IEP recommends adopting pro forma contract language that links the accounting requirement obligation directly to the requirements established by the California Energy Commission (CEC), rather than to WREGIS. The CEC is empowered by statute to determine eligibility under the RPS statutes. The CEC's future eligibility requirements may or may not prescribe participation in WREGIS as its agent for purposes of accounting or tracking, but the contract between the Buyer and Seller need not require anything more than adherence to the CEC's requirements. Statutes may change over the 20-year term of a PPA, but the process for dealing with changes in statute is much clearer than for changes in non-governmental entities like WREGIS.

Second, IEP notes that the pro forma agreement does not have a general provision that describes how the parties will attempt to accommodate changes in law. (The non-negotiable provisions required by the Commission address what happens if a change in law affects a project's status as an Eligible Renewable Resource or disqualifies the output of the facility from counting toward RPS goals.) IEP recommends adding to the pro forma a general change in law provision. This addition would accommodate the inevitable changes in law that will occur over the lifetime of these long-term contracts.

IV. COMMENTS ON SDG&E'S PROCUREMENT PLAN

A. Flat TOD Factors

In its discussion of "lessons learned," SDG&E alleges that some developers have provided unrealistic generation profiles that have resulted in greater-than-expected payments to the generator. SDG&E previously proposed to set limits on generation during each time-of-delivery (TOD) period, and it now proposes to revise all of its TOD factors to 1.0, which IEP understands to mean that a single price will be paid for all generation, on-peak and off-peak, regardless of season.

IEP notes that for 30 years, the utilities and policy advocates have urged development of pricing mechanisms that better align generation output and electricity demand. Differentiated TOD factors were determined to be one of the tools to achieve this alignment. Thus, IEP is surprised to see proposals that reverse this policy.

SDG&E's proposal is an overreaction to a problem affecting only a small number of projects. SDG&E can address unrealistic generation profiles by requiring more detailed information in the bid process. Flat TOD factors, however, remove all incentive to increase generation when the system's needs are the greatest. Moreover, the value of generation at different hours and seasons will not be constant, so the true TOD factors will be concealed from sellers and known only to SDG&E. In addition, SDG&E's contention that "This change will make no difference in the price paid to developers" is not true for all technologies. Developers of solar energy projects understand that they can generate electricity only when the sun shines, and they include TOD factors in their forecasts of the revenues associated with generation during peak TOD periods when they develop their bids.

IEP opposes SDG&E's proposal to flatten the TOD rates unless SDG&E can provide a more detailed assessment of the potential impacts of the proposed change. IEP understands that utilities should adjust the TOD periods as demand patterns change. As the peak period shifts from mid-day to later afternoon and evening, the peak TOD period may need to be redefined, and the TOD factors may need revision. Setting all TOD factors at 1.0, however, is an arbitrary act that does not fairly reflect system conditions and needs, and it will risk resurrecting the complaint that generation is not aligned with demand. The Commission should reject SDG&E's proposal.

B. Curtailment

SDG&E proposes to have an unlimited right to economically curtail production from renewable generators and to require generators to install an automated dispatch system and related software to implement curtailment orders.[11] SDG&E will compensate the generator for economic curtailments ("Economic Dispatch Down") but not for curtailments related to the operation of the transmission grid ("System Dispatch Down").

Under SDG&E's pro forma PPA, there is no limit to the uncompensated curtailments related to system conditions, and it is unclear whether this unlimited potential for uncompensated curtailments is financeable. As noted elsewhere, IEP supports a range of solutions for Buyers and Sellers to consider when contracting, such as those proposed by SCE. IEP recommends that the optionality proposed by SCE should be included in SDG&E's RPS procurement plan to provide a measure of certainty about the price for curtailed energy from RPS-eligible resources.

C. Capping the Cost of Transmission Upgrades

SDG&E proposes to set an unspecified cap on transmission upgrades. If the cap is exceeded, SDG&E can decide not to move forward with a contract.[12]

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[11] SDG&E's RPS Procurement Plan, p. 30.
[12] SDG&E's RPS Procurement Plan, p. 49.

The problem with this approach is that the costs of transmission upgrades are unpredictable and outside the control of the project developer. In recent years, utilities have strongly encouraged renewable energy providers to elect FCDS so that the utility could receive Resource Adequacy Capacity (even though the RA capacity of wind and solar projects is small in relation to the project's nameplate capacity). But FCDS requires significant transmission upgrades to ensure full deliverability, and the costs of those upgrades can far exceed any benefit the utility receives from the small RA capacity benefits.

Other approaches are preferable to SDG&E's solution. If the cost of FCDS is too great, then the project should have the ability to elect Energy Only Status, which should reduce the cost of transmission upgrades considerably. Another approach is to require a defined maximum contribution by the developer toward excess transmission upgrade costs as an alternative to SDG&E's backing out of the PPA.

V. CONCLUSION

IEP respectfully urges the Commission to consider these comments as it deliberates on the draft RPS procurement plans.

Respectfully submitted this 2nd day of July, 2014 at San Francisco, California.

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By /s/ Brian T. Cragg
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VERIFICATION

I am the attorney for the Independent Energy Producers Association in this matter. IEP is absent from the City and County of San Francisco, where my office is located, and under Rule 1.11(d) of the Commission's Rules of Practice and Procedure, I am submitting this verification on behalf of IEP for that reason. I have read the attached "Comments of the Independent Energy Producers Association on the RPS Procurement Plans," dated July 2, 2014. I am informed and believe, and on that ground allege, that the matters stated in this document are true.

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

Executed on this 2nd day of July, 2014, at San Francisco, California.

/s/ Brian T. Cragg
Brian T. Cragg

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