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 R.11-05-005

COMMENTS OF THE GREEN POWER INSTITUTE ON THE 2013 RPS PROCUREMENT PLANS

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Pursuant to the May 10, 2013, *Assigned Commissioner's Ruling Identifying Issues and Schedule of Review for 2013 Renewables Portfolio Standard Procurement Plans Pursuant to Public Utilities Code Sections 399.11 et. Seq. and Requesting Comments on a New Proposal*, as modified by a May 23, 2013, email *Ruling* by ALJ DeAngelis granting an extension to file Comments until July 12, 2013, in Proceeding R-11-05-005, the **Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program**, the Green Power Institute (GPI), a program of the Pacific Institute for Studies in Development, Environment, and Security, provides these *Comments of the Green Power Institute on the 2013 RPS Procurement Plans*.

On June 28, 2013, the three large IOUs submitted their annual *RPS Procurement Plans*, each comprising hundreds of pages of material. In addition to the three large IOUs, the other jurisdictional energy providers also submitted their *RPS Procurement Plans* on June 28. This is an enormous amount of information on which to file comments a short two weeks later. Due to limited resources, we are limiting our *Comments* to the *RPS Procurement Plans* of just the two largest IOUs, PG&E and SCE, and regrettably, even by limiting our focus to just these two plans we are not able to provide the level of analysis we believe would be appropriate.

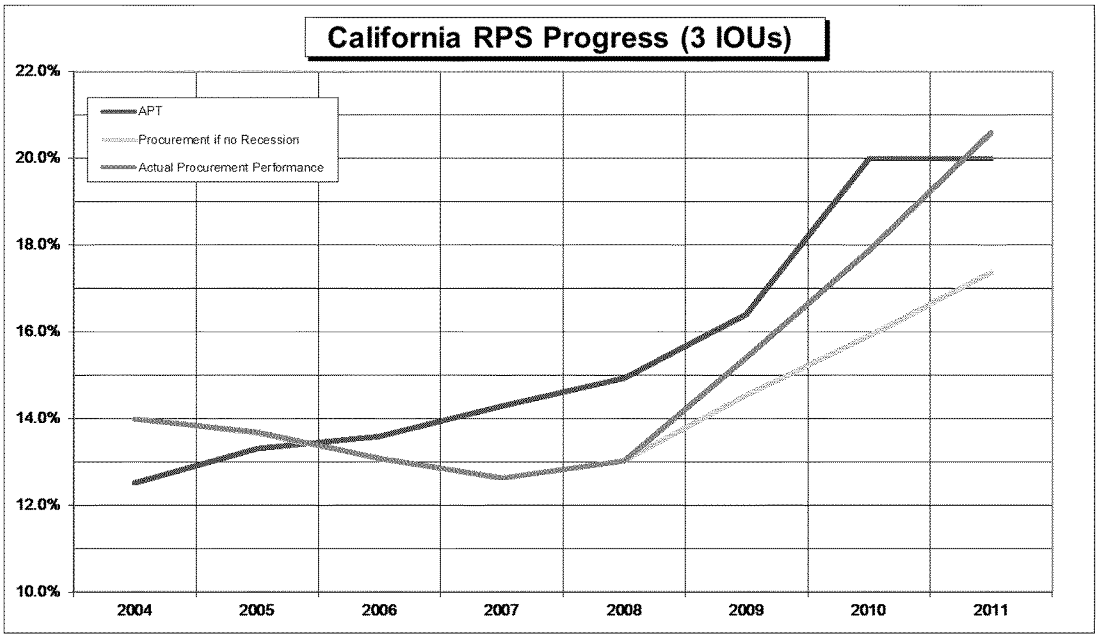
RPS Portfolio Supply and Demand

The underlying purpose for requiring electric service providers (ESP) to produce *RPS Procurement Plans* is to attempt to understand the future supply and demand outlook for RPS energy for each ESP that is subject to regulatory oversight by this Commission. California entered the second phase of its RPS program on January 1, 2011. The first phase, which ran from 2003 – 2010, was supposed to bring the state's energy-supply mix up to twenty-percent renewable by 2010. The second phase, which runs from 2011 – 2020, is supposed to increase the renewable content up to 33 percent by 2020. This is an aggressive goal, particularly considering the fact that a substantial proportion of the state's renewable-energy generating infrastructure has already entered its third decade of service.

Both PG&E and SCE are confident that they will achieve compliance with their RPS obligations for each of the three multiyear compliance periods that SB 2 1X creates for the time period 2011 – 2020. Although both utilities experienced chronic RPS-procurement shortfalls during the first phase of the RPS program (2003 – 2010), they both achieved the twenty-percent benchmark in 2011 (as did SDG&E), a landmark achievement in the state's efforts to increase renewable energy production, and they both hold significant portfolios of contracts for new capacity that are in various stages of development. In fact, PG&E and SCE are sufficiently confident in the sufficiency of their future RPS supplies that, for example, SCE has relieved its major biomass generator (~375 GWh/yr) of its contractual obligations and allowed it to find a new buyer and leave the SCE system, and on page 18 of its *RPS Procurement Plan* PG&E warns existing generators with contracts that are expiring between now and 2020:

> Third, existing RPS-eligible contracts that are expiring before 2020 face a different challenge. In order to be competitive, these near-term expiring contracts will need to offer extensions or new contracts at discounted prices because of the poor fit of near-term deliveries with PG&E's RPS need, or they will need to find other off-takers in the intermediate term.

While part of the good news about RPS procurement in the current decade is the result of new generators coming online and the total amount of statewide renewable generation increasing, another part of the good news is illusory, as it is a result of the deep economic recession that began in late 2008. Electricity demand for the three IOUs, which had been growing at an annual rate of approximately three percent per year prior to the collapse, fell at a similar rate for the following three years, through 2011. Thus, the calculated percentage of RPS energy in the supply mix during the three years following the onset of the recession was increasing due to both increases in RPS energy production (the numerator), and due to decreases in bundled-energy sales (the denominator). As shown in the chart below, if the economy had not collapsed, and load growth had continued through 2011 as it had been prior to 2008, RPS procurement by PG&E and SCE in 2011 would have been closer to 17 percent, not the 20-plus percent that was reported.



Although we don't have the final numbers yet, we know that electricity demand for both large utilities rebounded significantly in 2012. Nevertheless, both utilities appear to be projecting long-term demand growth for 2011 – 2020 at very modest levels compared to recent experience during economically robust times (approximately one-percent annually for 2011 – 2020 vs. three-percent annually for 2003 – 2008). We are concerned about these assumptions for several reasons:

- The projections begin from a base year, 2011, whose demand is significantly depressed compared to what would be expected in a healthy economy. Although recovery from the 2008 recession has been slow, historical experience suggests that when electricity demand does rebound following an economic slowdown, it is likely to experience a significant upward bump for a couple of years before a longer-term, more moderate annual growth rate is assumed.

- A major part of the rationale offered by both utilities for the assumed low annual growth rate in electricity demand for 2011 – 2020 is that aggressive efficiency efforts planned for the period will ease demand growth compared to past periods of robust economic activity. However, the fact is that the growth rate in electricity demand during 2003 – 2008, approximately 3-percent per year, occurred during a period when comparably aggressive efficiency efforts were in effect.

- Despite a host of state policies favoring the development of the electric vehicle market in California, and the potential size of the market and its demand for energy, the demand growth projections used by the IOUs in their *RPS Procurement Plans* do not appear to take demand growth for transportation use into account at all. This potentially very large new source of demand simply cannot be ignored.

For these reasons and more, the GPI believes that the utilities are seriously underestimating the potential for future demand growth for electricity in California, and thereby seriously underestimating the potential future need for RPS energy in the state (the net-short). For example, if demand were to grow at 3-percent annually instead of the utility-assumed growth rate of 1-percent annually during the period 2011 – 2020, then the calculated percentage of RPS energy in the supply mix in 2020 would drop by more than four percent from the numbers being projected by the utilities, and the Commission would probably have a very different perception about the future adequacy of the state's renewable-energy generating infrastructure.

Our concern about the utilities underestimating their future need for RPS energy is exacerbated by our concern that they continue to overestimate the success rate for their portfolios of projects-in-development. PG&E, for example, which is the utility that assumes the lowest demand growth rate of the three IOUs, states on page 16 of their *RPS Procurement Plan* that they are revising upward their estimates of the probabilities of successful completion for projects in their portfolio. Moreover, the tables in Appendices 1 and 1A both show a zero percent "Forecast Failure Rate (%) for New Projects not yet online," and zero "Voluntary Margin of Over-Procurement (GWh)." The discussion about minimum procurement margins, on pages 81 – 84 of PG&E's *RPS Procurement Plan*, explains that their confidence in producing procurement surpluses during the middle years of the decade, and the increasing quality of the projects they are choosing in their solicitations, convince them that for now they do not need to maintain a voluntary over-procurement margin, even while they are increasing their estimates of success rates for their projects-in-development. In our opinion the combination of underestimation of future RPS energy demand, combined with an overestimation of success rates for projects-in-development and no voluntary over-procurement margin, is a recipe for disaster.

We note that while displaying confidence about their ability to satisfy their RPS procurement obligations for the three multiyear compliance periods spanning 2011 – 2020, nevertheless when discussing risk factors the utilities appear to want to put all of the risks of project completion onto the backs of the developers, reasoning that the risk of project completion is not under their control. While it is true that the risk of completing a particular project is not under the control of the off-taking utility, in fact the utility does have control over the risks of project completion for their portfolios as a whole. Portfolio risks are controlled by properly estimating the risks of the component contracts in the first place, and balancing these risks by reciprocal over-procurement. For example, if the overall risk of failure for a portfolio is 30 percent, then the reciprocal over-procurement factor is 43 percent (1-(1/0.7)).

The GPI urges the Commission to order the utilities to include a substantially higher demand-growth rate sensitivity case in their *RPS Procurement Plans*, to employ realistic and reasonable estimates for project-development risk, and to adopt prudent over-procurement margins in their plans.

Renewable Integration and Least-Cost Best-Fit Ranking

Both utilities describe their least-cost / best-fit (LCBF) bid-ranking methodologies for their 2013 RPS solicitations in their *RPS procurement plans*. There appears to be little change in LCBF treatment from previous solicitations. A general overhaul of the least-cost / best-fit process has been promised for some time in the RPS proceeding. Item no. 3 in the

Scope of Issues in the September 12, 2012, *Amended Scoping Memo and Ruling of Assigned Commissioner*, reads (pgs. 5-6):

> 3. Improvements to least cost best fit (LCBF) methodology and evaluation of bids for RPS procurement, including but not limited to:
>
> -- implementation of new LCBF requirements set by SB 2 (1X);
>
> -- review of resource adequacy value, integration cost adders, congestion cost adders, time of delivery factors, and similar elements potentially affecting evaluation of RPS bids;
>
> -- development of a more robust relationship between RPS procurement evaluation methodology and elements of the determination of system need through the LTPP proceeding.

With concerns about the integration of increasing amounts of intermittent renewables now a major focus of not only this Proceeding but also the LTPP Proceeding, as well as renewed concerns about the capacity value of intermittent resources (Resource Adequacy), the need for expensive transmission investments to accommodate remote resources, and a system-wide demand curve whose peak appears to be drifting into later hours of the day, it is clear that all aspects of the LCBF process could benefit from an overhaul. Unfortunately, the overhaul has yet to begin, and there is no chance that it can be conducted in time to benefit the 2013 *RPS Procurement Plans* or solicitations. In the meantime, for the 2013 RPS solicitations both utilities describe an LCBF methodology that is virtually all LC, and no BF. One predictable consequence is an extreme lack of diversity that has shown up in the winning bids in past solicitations, and is likely to occur again in the 2013 solicitations.

PG&E laments the fact that Decision D.12-11-016 prevents it from using an integration adder in its 2013 RPS solicitation, and expresses its concern about the future operability of the grid with a much higher proportion of intermittent generation in the supply mix. SCE is also concerned about the cost of renewables integration, although less stridently so. Renewables integration is being addressed in the LTPP proceeding, but for purposes of the 2013 *RPS Procurement Plans* and solicitations, there are concrete steps that the utilities could take to produce a more diverse outcome.

In the opinion of the GPI, a functional LCBF methodology that properly values the BF side of the equation would provide multiple means to account for the needs of grid operability, even within the strictures of D.12-11-006. In particular, instead of trying to penalize intermittent generators by assessing an integration cost to their bids, the utilities could credit the bids of generators who can provide ancillary services, schedulable power, and/or flexible operating services to the grid. Although it may be impossible to do anything meaningful in time for the 2013 solicitations, if the LCBF overhaul is started soon, it could be conducted in time for the results to be incorporated into the 2014 solicitations.

RPS Costs

The cost of the state's RPS program has long been a matter of controversy and concern. The utilities have been warning since the inception of the program about its excessive cost to ratepayers. The GPI has long argued that, in fact, the program has cost ratepayers very little if anything to date. Part of the reason for this is that the RPS program, which was enacted in 2002, did not yield very much at all in the way of results (that is, increased production of renewable energy) until starting in about 2009 or 2010, when RPS procurement for the three IOUs finally began to rise above pre-RPS program levels. Thus, up until a couple of years ago the program could ot have cost ratepayers very much at all, because regardless of its cost it had produced very little new energy that was not already in the system.

Appendix 2 of PG&E's *RPS Procurement Plan* presents estimates of joint IOU costs for the procurement of RPS energy. In our opinion, the joint RPS procurement-cost information presented in the *RPS Procurement Plans* is misleading, and of little value. For example, in Table 1, the bottom row of the table, which presents the bottom-line calculation that is produced in the table, is labeled "Incremental Rate Impact*". In fact, as the footnote to the label explains, the values presented in this row are not incremental rate impacts at all:

> While the item is labeled "Incremental Rate Impact,"the value should be interpreted as an estimate of a system average bundled rate for RPS eligible procurement and generation, and not a renewable "premium." In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

The reader has no way of knowing what this cost means, or how to interpret it. It is presented completely without context. For example, how does this cost, which is expressed in ¢/kWh, compare with the cost of conventional generation,? To what extent does it protect ratepayers from the risks of price increases and price spikes in the short-term energy markets? The "Incremental Rate Impact" of RPS energy is shown in the table to have increased from 0.73 ¢/kWh in 2003 to 1.15 ¢/kWh in 2010. Most readers would interpret this to mean that the cost of renewable energy increased by almost 60 percent during this period, but this is not the case at all. In fact, the increase is mostly the result of there being an increasing proportion of renewable energy in the supply mix, not the result of increasing unit costs of renewable energy production.

The *RPS Procurement Plans* need to either provide reasonable and comparable information for other sources of energy that are in the supply mix, or, far more helpfully, they should present the **incremental** cost of RPS procurement, as the label in the table promises to do, but does something else entirely. The true cost of the RPS program to ratepayers is the amount, if any, of costs **above** what otherwise would have had to have been expended in order to procure the energy and services needed to operate the grid.

The ACR's Proposal for Biennial RPS Procurement Reports

In addition to reviewing the 2013 *RPS Procurement Reports*, the *Assigned Commissioner's Ruling* asks parties to comment on a proposal to lengthen the RPS Planning cycle to two years. The GPI does not support this proposal at this time, for a couple of reasons. For one thing, the proposal describes a two-year planning cycle, but it still requires the submission of annual updates in the off years. As far as we can tell these updates are almost equivalent to the proposed biennial plans themselves. Thus, we do not see that the proposal will really save very much time for either the Commission or the parties.

More importantly, as our above comments on the 2013 *RPS Procurement Plans* demonstrate, we do not believe that the planning process is sufficiently mature at this point in time to justify moving it to a two-year planning cycle.

Dated July 12, 2013

Respectfully Submitted,

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VERIFICATION

I, Gregory Morris, am Director of the Green Power Institute, and a Research Affiliate of the Pacific Institute for Studies in Development, Environment, and Security. I am authorized to make this Verification on its behalf. I declare under penalty of perjury that the statements in the foregoing copy of *Comments of the Green Power Institute on the 2013 RPS Procurement Plans*, filed in R.11-05-005, are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters I believe them to be true.

Executed on July 12, 2013, at Berkeley, California.

Gregory Morris