LBNL-58728

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Does It Have To Be This Hard?
Implementing the Nation's Most Aggressive Renewables Portfolio Standard in California

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August 2005

Submitted to: ***The Electricity Journal***

The work described in this paper was funded by the California Energy Commission, and by the Office of Electricity Delivery and Energy Reliability (Electric Markets Technical Assistance Program) of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

Disclaimer

Acknowledgements

The work described in this paper was funded by the California Energy Commission, and by the Office of Electricity Delivery and Energy Reliability (Electric Markets Technical Assistance Program) of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231. The views expressed in this article are those of the authors, and not necessarily those of their employers or funders.[1]

[1] Heather Raitt co-authored this paper in her individual capacity and not as an employee of the California Energy Commission. The views and opinions expressed in this article are therefore those of the author and not of the California Energy Commission. The Energy Commission has not reviewed or approved the article or its content.

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I. Introduction

In 2002, California enacted an aggressive renewables portfolio standard (RPS) that calls for the state's investor-owned utilities (IOUs), energy service providers (ESPs), and community choice aggregators (CCAs) to meet 20% of their electricity load with eligible sources of renewable energy by 2017 (publicly owned utilities in the state are required to develop their own RPS policies). To reach this target, each obligated load-serving entity must increase by at least 1% annually the percentage of its load served by renewable energy.

California's RPS could stimulate as much as 8,000 MW of new renewables capacity, making it the most ambitious state RPS in the nation in terms of potential capacity additions. Moreover, the state's Energy Action Plan[2] and the California Energy Commission's Integrated Energy Policy Report[3] have called for an acceleration of the RPS such that the 20% goal is met seven years early, by 2010. Governor Schwarzenegger has endorsed this accelerated schedule and has set a goal of achieving a 33% renewable energy share by 2020 for the state as a whole.

Much has already been accomplished under the state's RPS. Regulatory rules implementing major portions of the statute have been completed by the California Public Utilities Commission (CPUC) and the California Energy Commission (Energy Commission). Through interim renewable energy solicitations issued in 2002 and 2003, bilateral contracts, and more recent formal RPS solicitations, the state's three major IOUs have increased their purchases of renewable energy from approximately 19,190 GWh in 2002 to an expected 23,110 GWh in 2005.[4] From 2002 to 2005, Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) have increased the percentage of their load served by renewable energy by approximately 1%, 1.5% and 4.5%, respectively. And, in total, approximately 1,130-1,820 MW of new renewable energy capacity is under contract to the three IOUs, either already approved by the CPUC or otherwise awaiting approval, with more to come (Table 1).

At the same time, California's RPS is the most complex in the nation, and it should therefore come as no surprise that the state has experienced implementation challenges. Regulatory delays have slowed the process, and important elements of the state's policy, such as the application of the RPS to ESPs and CCAs, are just now being considered. Concerns have been raised not only on the substance of the state's RPS design, but also on the timeliness of implementation and the transparency of the overall process. Most of the increase in utility renewable energy purchases so far has come from existing and already operating renewable energy generators, and only recently has the California RPS begun to stimulate new renewable capacity additions. As a result, California as a whole has fallen behind schedule in meeting its aggressive renewable energy targets.[5]

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[2] California Energy Commission, California Public Utilities Commission, Consumer Power and Conservation Financing Authority. "Energy Action Plan." May 2003. http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF.
[3] California Energy Commission. "2004 Energy Report Update." CEC-100-04-006CM, November 2004. http://www.energy.ca.gov/reports/CEC-100-2004-006/CEC-100-2004-006CMF.PDF.
[4] California Energy Commission. "Implementing California's Loading Order for Electricity Resources." CEC-400-2005-043, July 2005. http://www.energy.ca.gov/2005publications/CEC-400-2005-043/CEC-400-2005-043.PDF.
[5] Op cit. 4.

Table 1. IOU Contracts for New Renewable Energy Capacity (MW)*

	PG&E	SCE	SDG&E	TOTAL
Wind	157 – 190	99 – 270	150	**406 – 610**
Wind Repowering	84 – 99	37	0	**121 – 136**
Geothermal	0	30 – 120	0	**30 – 120**
Biomass	0	12 – 37	56	**68 - 93**
Solar Thermal Electric	0	500 - 850	0	**500 – 850**
Small Hydropower	0	0	5	**5**
TOTAL	**241 - 289**	**678 - 1314**	**211**	**1130 - 1814**

* Includes contracts for new renewable energy capacity submitted to or approved by the CPUC since 2002. Capacity additions do not include SDG&E's 2004 RFO, as those contracts have not yet been announced. Capacity additions also do not include four contracts that SCE signed under its 2002 RFO, as one of those contracts has been terminated (TrueSolar), and information on the resource type and/or project size of the other three is not publicly available.

This article provides a stakeholder assessment of early experience with California's RPS. It is based on a longer document prepared for the Energy Commission, which reported results from telephone interviews with a diverse group of twenty-one California RPS stakeholders.[6] The insights gained from these interviews were supplemented with a review of relevant statutes, regulatory decisions, party testimony, and utility solicitation documents, as well as comparative information on the design of RPS policies in other states.

The goals of this article are to identify lessons learned from the early implementation of California's RPS, and to highlight areas of policy improvement needed for California to achieve its aggressive commitment to renewable energy. Experience with California's RPS may also offer lessons useful to other states struggling to design effective RPS policies, though certain elements of California's RPS are unique and are unlikely to be replicated elsewhere.

We begin by describing California's RPS, and identifying the multitude of design features that make California's policy unique among state RPS policies. We then summarize stakeholder perspectives, as gleaned from our interview results, on the California RPS in general, as well as on two of the more important issues to date: deliverability and transmission requirements, and the effectiveness of recent utility solicitations. We close with policy recommendations.

[6] Wiser, Ryan, Kevin Porter and Mark Bolinger. "Preliminary Stakeholder Evaluation of the California Renewables Portfolio Standard." CEC-300-2005-011, June 2005. http://www.energy.ca.gov/2005publications/CEC-300-2005-011/CEC-300-2005-011.PDF.

II. California's Unique RPS

To date, twenty-one states and Washington, D.C. have established RPS requirements. These standards have not been operating long enough to enable definitive conclusions on the best design and approach to RPS implementation, though preliminary policy recommendations have been offered elsewhere.[7] What is clear, however, is that the design of California's policy, as well as the regulatory process for implementing it, bears little resemblance to what is commonly seen in other RPS states.

As highlighted in Table 2, the implementation process associated with California's RPS is unique in several respects. Regulatory oversight responsibilities are distributed between two state agencies, the CPUC and the Energy Commission, while in other states a single agency typically has oversight responsibility. Whereas other states have consolidated multiple RPS design issues into single regulatory decisions, California's implementation agencies have chosen to address these issues within a large number of individual decisions.[8] Furthermore, unlike virtually all other states, California is developing RPS implementation rules for ESPs and CCAs separately from those applied to the state's IOUs (moreover, the regulatory scaffolding now developed for IOUs is unlikely to hold for ESPs and CCAs). Finally, in part driven by statute, the degree of regulatory oversight of California's IOUs in renewable resource procurement and bid evaluation has not been replicated in any other state RPS policy to date.

In addition to these process differences, the design of the California RPS (driven in large part by the statute itself) has required the CPUC and the Energy Commission to address issues that have simply not arisen in other states. For instance, the California RPS – by statute – caps utility payments for renewable energy at the market price referent (MPR, reflecting the estimated all-in cost of baseload and peaking gas-fired generation), with any costs above the MPR covered by the state's renewable energy fund through supplemental energy payments (SEPs), administered by the Energy Commission. In addition, the California RPS requires utilities to use a "least cost, best fit" (LCBF) process for bid evaluation, and the CPUC requires utilities to incorporate CPUC-approved bid-evaluation protocols, integration cost estimates, and qualitative evaluation

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[7] For an overview of RPS experience, see: Wiser, Ryan, Kevin Porter, and Robert Grace. "Evaluating Experience with Renewables Portfolio Standards in the United States." LBNL-54439, March 2004. http://eetd.lbl.gov/ea/ems/reports/54439.pdf. And, van der Linden, Nico, et al. "Review of International Experience with Renewable Energy Obligation Support Mechanisms." ECN-C—05-025, May 2005. http://eetd.lbl.gov/ea/ems/reports/57666.pdf.

[8] On June 19, 2003, the CPUC made threshold decisions on the basic structure and application of the RPS; laid out the general approach to be used for utility solicitations; and set compliance schedules, flexibility mechanisms, and penalties for noncompliance (D.03-06-071). On June 9, 2004, the CPUC established its methodology for establishing market price referents (MPRs) (D.04-06-015), adopted standard contract terms and conditions that govern power purchase agreements signed under the state's RPS (D.04-06-014), and established methods for ranking bids based on their expected transmission costs with transmission ranking cost reports (TRCRs) (D.04-06-013). On July 8, 2004, the CPUC defined the approach to evaluating bids under a least-cost, best-fit (LCBF) framework (D.04-07-029). On May 5, 2005, the CPUC clarified the participation of renewable distributed generation under the state's RPS (D. 05-05-011). On July 21, 2005, the CPUC revised its TRCR requirements for the 2005 solicitation cycle (D. 05-07-040), and approved (with modifications) the utilities' 2005 renewable energy procurement plans and solicitations (D. 05-07-039). The Energy Commission, meanwhile, has published its Renewable Portfolio Standard Eligibility Guidebook (500-04-002F1), its New Renewable Facilities Program Guidebook (500-04-001F), and its Overall Program Guidebook for the Renewable Energy Program (500-04-026), as well as related policy decisions.

factors into their bid evaluation processes. To satisfy legislative requirements that utilities consider transmission costs in evaluating bids, the CPUC also requires utilities to develop formal transmission ranking cost reports (TRCRs) in an attempt to estimate the cost of transmission expansion needed to access potential renewable energy projects. The CPUC has also developed a limited set of standard contract terms and conditions for use by the state's IOUs in procuring renewable energy. To help oversee procurement decisions, the CPUC has established procurement review groups (PRGs), consisting of non-market participants willing to sign nondisclosure agreements, for each of the state's IOUs. Finally, the CPUC does not currently allow renewable energy credits (RECs) to be unbundled and sold separately from the underlying electricity for the purpose of RPS compliance, as is done in other RPS states. All of these provisions are either unique to California, or else exceed the requirements imposed by most other states in implementing their RPS policies.

Table 2. Unique Features of California's RPS

Unique Implementation Process	Unique Design Elements
• Jointly administered by two state agencies • Little consolidation of regulatory decisions • Different rules for IOUs and ESPs/CCAs • Extensive oversight of procurement	• MPRs & SEPs (procurement contingent on SEP availability) • LCBF evaluation • TRCR process • Standard contract terms and conditions • Procurement review groups • Full bundling of RECs with electricity

Perhaps of most importance, separating payments between electricity suppliers (up to the level of the MPR) and the state (through SEPs) creates regulatory responsibilities that would not otherwise exist (though other states sometimes use state renewable energy funds to help support their RPS, no other state has constructed an MPR-SEP framework). First, this practice *directly* imposes MPR and SEP process requirements on the CPUC and the Energy Commission. Perhaps less obvious, it is also *indirectly* responsible for increasing the level of regulatory oversight needed for utility procurements (and, therefore, LCBF requirements, standard terms and conditions, TRCRs, procurement review groups, etc.). Without such oversight, the state's IOUs and ESPs/CCAs may have an incentive to purchase renewable energy at high costs (their own costs capped by the MPR), thereby depleting the state's SEP funds more rapidly than might be socially optimal.

In states without such a separation of payments, the perceived need for detailed regulatory oversight is reduced, at least to some degree. As a result, in a large number of states, the public utility commissions' primary responsibilities are (or will be) to review compliance after the fact. In other states, the legislature and/or the regulatory commission have established limited contracting requirements, and contract pre-approval is the norm. In no state is the degree of oversight or the corresponding number of detailed and complex RPS design issues similar to that experienced in California.

Partly as a consequence of these unique features, California's RPS implementation process has been more time-consuming than those in most other states. As shown in Figure 1, it took nearly two years for the state's energy agencies to develop the regulatory framework for the state's three large IOUs, and the development of implementation rules for ESPs and CCAs continues to this day; many other RPS design elements also remain unresolved.[9] This is particularly notable given the short period of time between enactment of the RPS and the state's first RPS obligations: only about four months separated the Governor's signature in September 2002 and the first RPS requirement, which nominally began on January 1, 2003. Though Figure 1 suggests that the implementation process has also been slow in some other states (most notably Massachusetts), these states have often had a generous cushion of time between the enactment of the law and the first obligation, thereby reducing the need to expedite implementation regulations.

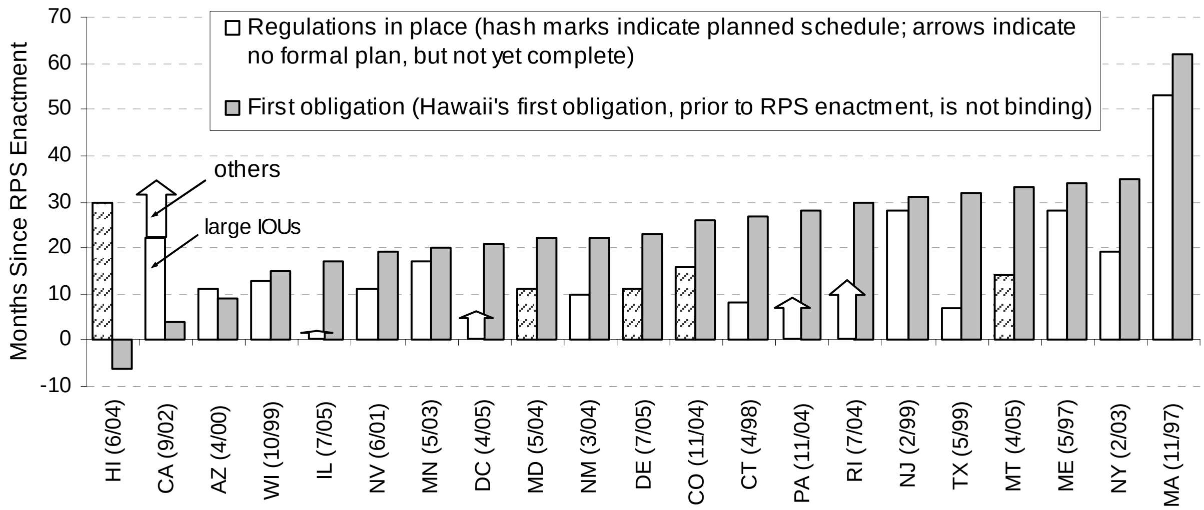

Figure 1. Implementation Timeline for State RPS Policies (as of August 2005)

[9] In addition to developing rules for ESPs and CCAs (whose purchase requirements began as early as 2003), the CPUC and Energy Commission have ongoing deliberations to, among other things, consider the use of time-of-delivery differentiated MPRs (and other changes to the MPR calculation methodology), further define the role of distributed generation under the RPS, develop a functional west-wide tracking system for renewable energy, encourage transmission expansion to renewable resource-rich areas, and reconsider whether unbundled renewable energy certificates (RECs) might be allowed.

III. Insights from Stakeholder Interviews

Given the complexity of California's RPS, and the amount of time it has taken thus far to implement, it should be no surprise that stakeholders have diverse opinions about how to improve the process. Here we summarize many of these opinions, as gleaned from stakeholder telephone interviews that were conducted on the basis of a standard interview guide.

We sought to interview only those stakeholders likely to be familiar with the state's RPS, focusing initially on the state's three major IOUs, renewable energy developers and developer associations, nonprofit organizations, and ESPs/CCAs. Ultimately, we were successful in interviewing twenty-one different stakeholders, including three utilities, ten developers, three developer associations, three nonprofit groups, and two ESP/CCA representatives. Our sample is clearly dominated by developers and developer associations, a point that should be remembered when considering the interview results.

A. General Views of the California RPS

Views of how the RPS policy is working in general range from observations that the policy is structured appropriately and that California is off to a good start, to the viewpoint that the policy is an unmitigated disaster. Many respondents reported that the process has been overly complex and lengthy and that the outcome is far from ideal, but that solicitations are now occurring and contracts are being signed. As a result, many respondents – even those not satisfied with progress to date – believe that a total redesign of the RPS would not be appropriate at this time.

As shown in Figure 2, when asked to rate the overall design and effectiveness of the California RPS (where 1 means the policy is broken and not working and 5 means the policy is operating flawlessly), respondents assigned the policy an average rating of 3, with non-profit associations and utilities generally offering more positive assessments, and developers, developer associations, and ESPs/CCAs proffering more negative views.

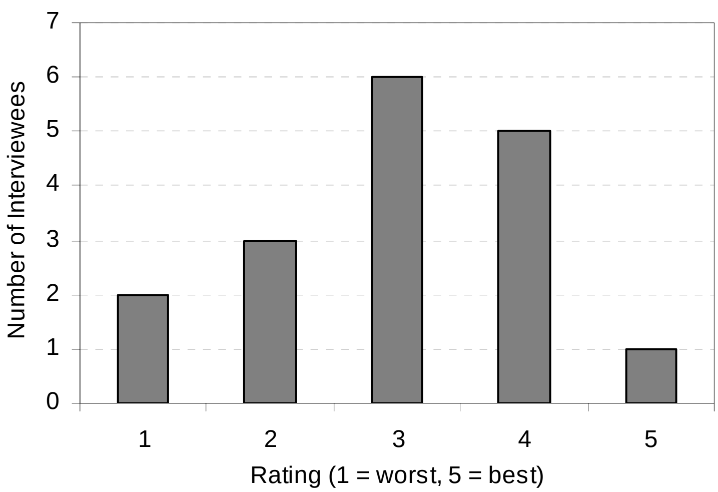

Figure 2. Overall Rating of the California RPS

A subsequent question asked how the respondents felt the various elements of the California RPS were working, using the same 1-to-5 rating. Figure 3 presents the survey results. Stronger elements included the renewable energy eligibility rules, utility compliance flexibility mechanisms, and the LCBF evaluation process. Areas of greatest concern included support for transmission expansion, the TRCRs, administration of SEPs, and the renewable electricity deliverability requirements. These rankings were also consistent with responses to other, more open-ended questions, though many respondents also noted frustration with the regulatory pace of applying the RPS to the state's ESPs.

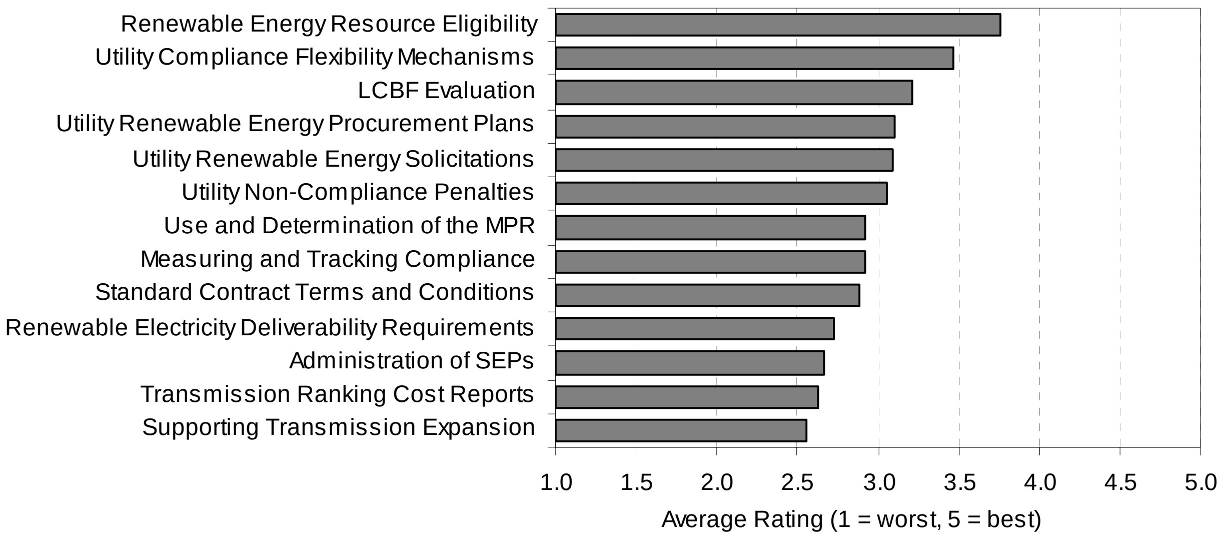

Figure 3. Ratings of RPS Design Elements

With regards to the regulatory process, implementation delays and complexity were the principal concerns of the respondents. Several respondents cited the large time lags between RPS decisions as reflective of a lack of consistent focus at the CPUC and a tendency to operate in "fits and starts." Others complained that an overall roadmap for the resolution of issues had not recently been provided by the CPUC. A number of respondents also urged the CPUC to act more aggressively on transmission expansion needs. Many recognized that increased and more consistent staffing at the CPUC on RPS issues was needed; similar needs exist at the Energy Commission. Interviewees generally praised the open workshops used by the CPUC and the Energy Commission to bring parties together and discuss issues in a collaborative fashion.

B. Deliverability and Transmission Requirements

As reflected in Figure 3, issues associated with the delivery and transmission of renewable energy were viewed by many to be among the most important barriers to the achievement of California's aggressive renewable energy goals. Some of the key features of California's requirements are described below.

- **REC Bundling and Deliverability:** Though debate remains on the legal authority of the CPUC to allow unbundled trade in RECs absent new legislation, at present such trade is disallowed for the California RPS. Instead, renewable electricity and its associated attributes must remain bundled. As such, California is one of only four states that do not allow unbundled RECs to qualify under their RPS, and is the only state with competitive ESPs that does not allow unbundled RECs.[10] Out-of-state generators are required by the Energy Commission to demonstrate the delivery of their generation to an in-state market hub or substation located within the CA ISO control area, thereby treating the delivery of out-of-state generation in the same way as in-state generation. Until recently, California's IOUs required delivery of RPS-eligible power (whether from in-state or out-of-state projects) to their respective service territories.

- **TRCRs:** To account for the potential cost of network transmission expansion to deliver generation from individual renewable energy projects to utility load, the CPUC requires that each utility develop a TRCR prior to issuing an RPS-driven renewable energy solicitation. These reports estimate the cost of needed transmission expansion for potential renewable energy projects that may subsequently bid into a utility renewable energy request for offers (RFO). In evaluating the relative economics of different renewable energy proposals, the state's IOUs are to use the results of the TRCR or, if available, more detailed system impact studies completed through the CA ISO's interconnection process. Utilities in other RPS states also consider transmission expansion costs, but typically not through formal TRCRs that are approved by the regulatory commission and then applied in bid evaluations.

Since the time the stakeholder interviews were conducted, California's RPS delivery requirements have been modified to allow for a broader range of delivery locations. Specifically, in July 2005, the CPUC (in D.05-07-039) *required* the utilities to accept bids from out-of-service-territory projects that would deliver their electricity *anywhere* within the California ISO system, and *allowed* the utilities to accept delivery anywhere in California. Bids for delivery outside of a utility's service territory may, however, be disadvantaged in the bid evaluation process, as utilities are allowed to consider potential re-marketing, swap, and congestion costs and risks in ranking bids. This decision also reiterated that renewable energy bids may include curtailability attributes to reflect transmission constraints, and required the utilities to consider such bids. Furthermore, in Decision 05-07-040, the CPUC altered the TRCR process somewhat by allowing the projected cost of new transmission to be allocated on a pro-rata basis assuming that the transmission addition is fully loaded, and not allocating the full cost of the upgrade to an individual project that would not fully use the addition.

These changes (and in particular those in D.05-07-039) are consistent with the recommendations of the majority of our interviewees, who noted that the requirement to deliver to the utilities' service territories was not serving the objectives of the California RPS. In fact, allowing flexibility on in-state delivery points may have been the single most consistent recommendation relating to the subject of deliverability.[11] In addition to those changes already made by the CPUC, respondents identified several other near-term actions to ease deliverability constraints:

- **Shaped Renewable Electricity Products:** Several interview respondents expressed the desire for the CPUC and Energy Commission to specifically allow renewable energy

[10] The others are Iowa, Hawaii, and Minnesota (note that Minnesota is exploring the use of unbundled RECs)
[11] Note that utility interviewees wanted the flexibility to accept such bids, but did not want to be required to accept them.

developers to offer “shaped” or “firmed” renewable electricity products. Effectively, this would allow utilities to purchase RECs bundled with electricity delivered to the utility's service territory, but delivery of that electricity would not necessarily be coincident with the hour-to-hour production of the renewable generator. RECs would be unbundled from their underlying electricity, and rebundled with system power at another time. This places re-marketing and congestion risks on the renewable energy developer, but also allows the developer to deliver a shaped product to the utility that may avoid the need for costly transmission additions between utility service territories.

- **Busbar Delivery:** Dispute over whether delivery should occur at the generator's "busbar" or at the utility's "load aggregation point," especially in the event of the market redesign of the CA ISO, was apparently a primary reason for some of the delays experienced under the utilities' 2003/2004 RFOs. A redesign of the CA ISO market will likely change congestion paths, and introduce new and uncertain delivery costs and risks. A number of developers and developer associations cited a desire for CPUC-ordered standardization of the treatment of this issue on a going-forward basis, though utilities disputed the need for such standardization, and the CPUC ultimately declined to implement such a change in D.05-07-039 for in-territory renewable projects (as noted earlier, out-of-territory projects may now deliver anywhere in the CA ISO).

- **Out-of-State Delivery:** Most survey respondents did not voice support for significantly relaxing the deliverability standards for out-of-state generators (at least not in the near future). There was, however, at least some desire for a small tweak to the state’s out-of-state delivery requirements. Specifically, several respondents expressed a desire for developers to be able to deliver electricity to nearby out-of-state market hubs or substations (such as the California-Oregon Border, or the California-Oregon Intertie), with the purchasing utility arranging for transmission between those hubs and their in-state service territory (rather than the developer being responsible for that delivery). The Energy Commission’s deliverability rules appear to preclude these arrangements at the present time, and whether legislation is necessary to make this adjustment is subject to debate.

Interestingly, many interview respondents suggested a "go slow" approach to fully unbundled RECs, especially those associated with out-of-state generation. In fact, there was little support for broadly allowing unbundled RECs from outside of the state to qualify for the state's RPS, at least at this time. Most seemed to believe that the state should begin by experimenting with some of the near-term actions described above, with limited forms of in-state unbundled RECs trading being allowed over time. A more aggressive stance towards pursuing unbundled RECs was offered by the state’s ESPs and CCAs, however, and the state’s three major utilities also expressed varying degrees of interest in unbundled RECs trade.

With respect to transmission, there was little consensus on the effectiveness of the TRCRs. Several developer respondents noted that the TRCR process – which in their view prioritizes all existing uses of the transmission system ahead of new renewable energy – is in violation of the state’s preferred “loading order,” which favors renewable over other forms of generation. Others questioned whether the TRCRs were sending accurate and useful signals to developers, but were not sure how to improve the process. The states’ utilities, on the other hand, felt that the present

TRCR process is consistent with CA ISO tariffs, and fairly allocates the expected costs of transmission expansion to renewable energy bids.

Though there remains disagreement on the TRCR process, nearly all survey respondents were united on the need for more transmission in the state to access some of the state's more remote renewable energy sources. Many urged the CPUC to devote significantly more staff and resources towards this task, and quickly. Some believe that the CPUC has not done enough to follow statutory requirements that it make findings, where supported by the record, that new RPS-driven transmission facilities will provide benefits to the transmission network and are necessary to achieve the RPS goals, and that utilities can recover their costs through retail rates in the event that FERC disallows recovery in wholesale transmission rates. Other respondents, however, believe that transmission cost recovery is a FERC matter, and also noted the difficult "chicken and egg" problem of expanding transmission without firm developer commitments to build facilities in that area. Others noted that the approval process for new transmission is too long and urged a more expedited process. Overall, a more proactive and coordinated approach to identifying priority transmission investments was highlighted as a critical need.

C. Recent California Utility Solicitations

In advance of formal RPS requirements, each of California's major IOUs was required to issue "interim" renewable energy solicitations in 2002 (D. 02-08-071). California's IOUs have also had (and continue to have) the opportunity to execute contracts via bilateral negotiations, outside of formal solicitations, as long as certain conditions are met. Many of the resulting contracts have been with existing renewable facilities that were previously selling to other parties in California.

California's first formal RPS solicitations were issued in July 2004 by PG&E and SDG&E. SCE was not required to issue a solicitation in 2004, in part because it was still completing a voluntary 2003 renewable energy RFO. A moderate amount of new renewable energy capacity is now under contract to PG&E and SCE, as a result of these most-recent solicitations: 185-233 MW for PG&E (all wind), and 642-1278 MW for SCE (wind, biomass, geothermal, solar).[12] SDG&E has yet to announce any contracts as a result of its 2004 RFO. Meanwhile, the utilities' renewable energy RFOs for 2005 have recently been approved by the CPUC.

A substantial number of the interview questions related to the 2003/2004 solicitations, seeking lessons learned and recommendations for the next round of RFOs. Here we summarize some of the most important observations from respondents, including concerns about undue delays, as well as the degree of price competition and the very real prospect of contract failure.

Delays in Utility Renewable Energy Solicitations

Despite the seeming success of these initial solicitations, significant concerns have been expressed about the delays that were experienced. Compared to the indicative schedules offered in the RFOs (4, 5, and 9 months for SCE, PG&E and SDG&E, respectively), SCE experienced a 14-month delay, PG&E a 4-month delay, and SDG&E a 4-month (and counting) delay. With

[12] These contracts have either already been approved by the CPUC, or else have been submitted to the CPUC for approval.

aggressive renewable energy goals, and with plans for each utility to issue annual solicitations in order to achieve these goals, the initial delays are problematic.

These delays, however, should be viewed in context. First, each of the utilities clearly stated that its RFO timeline was indicative only, and SCE's solicitation was done voluntarily prior to a formal RPS RFO. Second, there is little doubt that a number of "kinks" in the RPS solicitation process had to be ironed out in this first round of RFOs. Third, it is not altogether uncommon for renewable energy solicitations to take some time between issuance and ultimate contract signature. In fact, California's recent solicitation timelines (with the possible exception of SCE's 2003 RFO) have not been dramatically out of line with experience elsewhere with both renewable energy and all-source solicitations.[13]

Though the specific reasons for the solicitation delays in California vary by utility, there was a considerable amount of agreement among interview respondents on the source of these delays:

- underestimates of the time required to negotiate with bidders, and the uniqueness and complexity of each individual deal;
- inadequate and poorly structured standard contracts, which often led to "start from scratch" negotiations;
- disputes over power delivery points (i.e., busbar vs. utility load aggregation points) in the event of CA ISO market re-design; and
- lack of utility staffing, staff continuity, and management focus.

Additional causes for delay cited by some respondents included the need to develop bid evaluation protocols; risks associated with expiration of the federal production tax credit (PTC) and turbine shortages, which caused some wind developers to drop out of negotiations mid-stream; unresponsive offers; negotiations related to performance standards, development milestones, credit requirements, and power scheduling; and regulatory delays associated with the calculation of the MPR.

Despite general agreement on the sources of the delays, respondents offered a diverse set of opinions when asked whether any policy changes should be made to speed the solicitation process. This is, in large part, due to the fact that most interviewees felt that much had been learned from the 2003/2004 RFOs and, as a result, that the 2005 RFOs would likely proceed more smoothly and somewhat more rapidly. There were, therefore, mixed views on whether to set firm regulatory deadlines for utilities to submit contracts to the CPUC for review: many respondents were open to considering such deadlines, but many also seemed to believe that additional experience should be gained with the current solicitations before standard deadlines are established. Other respondents thought that the CPUC should instead simply rely on the prospect of vigorously enforced non-compliance penalties to motivate timely action, as is the practice in some other states. Some developer respondents also called for further contract standardization, ranging from minor tweaks to a complete overhaul. Finally, some developers sought the return of "standard offer" contracts, where utilities offer a fixed price contract for a fixed term to any generator willing to accept the terms and conditions.

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[13] See Table 5 in op cit. 6.

Price Competition

A perhaps more serious long-term concern relates to the degree of price competition in the RFOs. The competitiveness of the 2003/2004 RFOs was generally viewed to be reasonably strong by those survey respondents familiar with the solicitations; note, for example, that all projects selected so far have come in under the MPR, and therefore have not required SEPs. Nonetheless, numerous respondents expressed concerns that the renewable energy supply curve was not as deep as one might hope, and that significant SEP funds may be necessary in the near future, especially if deliverability issues were not addressed.

Several respondents noted that the delivery rules and the TRCRs (as they existed at the time of the survey) effectively required renewable projects to be located within the utility service territory that they are to serve, severely limiting potential supply competition. Others highlighted the fact that some renewable developers appear to be pricing their projects based on supply costs, perceived risk, and current market prices for conventional generation, and that the proliferation of utility RFOs and the acceleration of the RPS targets may be increasing prices. Still others observed that onerous deposit, credit, and performance terms were raising the cost of doing business and both reducing the number of bids received[14] and increasing the bid prices for those proposals that are received. Others thought that the MPR may be inflating bids, as some developers have apparently considered it a starting point for negotiations.

Many parties suggested that additional leniency on the delivery rules, and a more focused effort on new transmission, would be needed to ease these possible supply constraints. Others suggested changes to the TRCRs, more flexibility in procurement options and timetables, and less onerous bid deposits, credit requirements, and performance guarantees.

Contract Failure

A large number of respondents, spanning all stakeholder types, also voiced serious concerns that a number of the renewable energy projects under contract with the state's utilities would not ultimately deliver as promised, citing fuel supply risks, transmission constraints, and other issues. Experience with the Nevada RPS, for example, shows that the risk of contract failure is all too real; a large number of renewable energy projects under contract to the Nevada utilities have either experienced construction delays, have had difficulties obtaining financing due to the poor financial health of Nevada's utilities, or have been terminated altogether. There is therefore a significant risk that the state's utilities will ultimately not purchase the requisite amount of renewable energy to meet California's aggressive goals, and will cite development failures as a reason to avoid penalties in case of under-compliance.

A number of interview respondents believe that California's policymakers need to foresee the upcoming "train wreck," and either ensure that utilities are over-contracting for renewable energy to account for project drop-outs, or alternatively, make it clear that they will not bend to later requests for compliance flexibility if and when projects fail. As an example of the former strategy, Nevada's utilities have recently proposed to the Nevada PUC that they seek to "over-

[14] A number of developer respondents reported that they and others had chosen not to bid, as a result of cumbersome and onerous requirements imposed by the solicitations. Some of these developers reported that they preferred to bid into renewable energy RFOs from California's municipal utilities or from out-of-state utilities.

procure" renewable energy under the expectation that some fraction of contracted generation will experience development or operational challenges.[15] Other interviewees wondered to what degree bid deposits, credit requirements, or bid evaluation practices could be structured to improve the chances of project success. At least one California utility respondent, on the other hand, voiced a strong belief that utilities should be offered flexibility in the event of contract failure.

[15] Nevada Power Company and Sierra Pacific Power Company. "Compliance Filing to Meet the Renewable Portfolio Standard." August 2005, filed with the Public Utilities Commission of Nevada, Docket No. 05-4003.

IV. Conclusions and Recommendations

California's RPS is unique in its design and complexity, and consequently has required a great deal of regulatory oversight and time to implement. Yet, after two-and-a-half years, utilities are conducting renewable energy solicitations, and renewable energy contracts are being signed.

Further progress has occurred since we conducted our interviews. The CPUC has relaxed the renewable energy delivery requirements; the TRCR process is being fine-tuned; rules for ESPs and CCAs are now beginning to be addressed; and the CPUC approved the utilities' 2005 RFOs, with changes that reflect lessons learned from the first round of solicitations.

Despite these recent developments, much can be done to improve the California RPS. Based in part on the stakeholder interviews, we offer the following high-level recommendations:[16]

Deliverability: Recent CPUC decisions have loosened the state's requirements for electricity delivery, but we believe that additional changes should be considered to further promote supply competition. First, we encourage the CPUC to specifically allow renewable energy developers to offer shaped products, as long as renewable electricity is delivered *into the state* under the present requirements. Allowance for such products may help developers avoid costly transmission investments and deliver products that better meet utility needs. We also recommend that the state's policymakers find that out-of-state renewable generators that deliver to a nearby but out-of-state market hub or substation are eligible under the state's RPS if the utility purchaser commits to arranging for transmission from that hub or substation to an in-state location. Finally, especially as the rules for ESPs and CCAs are developed, we believe that the state's policymakers should seriously consider loosening delivery requirements further by allowing fully unbundled RECs. In so doing, however, we encourage serious discussion of how SEPs might apply to REC transactions. Allowing RECs but not allowing REC transactions to access SEPs may provide little added flexibility, because purchasers may prefer higher-cost bundled transactions that can receive SEPs to lower-cost REC transactions that cannot.

Transmission: Inadequate transmission may be the most severe constraint to meeting the state's renewable energy goals. Though FERC holds jurisdiction over many of the thorny issues, the CPUC will need to exercise whatever statutory authority it has to support RPS-driven transmission investment in the state; this is especially true given FERC's recent decision declining network cost recovery for some of the proposed transmission upgrades in the wind-rich Tehachapi region. We also recommend continued analysis of the TRCR methodology, as stakeholders have expressed widely divergent views on the appropriateness of the current approach. Special transmission expertise may be necessary not only for the TRCRs but also for transmission issues in general, and the CA ISO should be encouraged to be more actively involved in supporting the state's renewable energy goals. Changes in CA ISO tariffs and in the interconnection queue that would support the development of geographically clustered renewable projects should also be considered. Overall, it is essential that the state's agencies take a more proactive and coordinated approach to identifying and resolving transmission problems.

[16] For additional details, and additional recommendations, see op cit. 6.

Procurement Practices: Though some have called on the CPUC to set hard deadlines for utilities to conclude their solicitations, in the hope that such deadlines will resolve the delays experienced to date, we believe that *blanket* deadlines of this nature are premature. The CPUC may wish to impose deadlines on a *case-by-case* basis in situations of undue delay, but we believe that more experience should be gained before resorting to a blanket policy that may put upward price pressure on bids. Especially if delays continue and problems persist, however, we would encourage consideration of solicitation deadlines, as well as greater standardization of form contracts, contract terms and conditions, bid deposits, and other elements of the procurement process.

Contract Failure: An emerging concern in California and other states with RPS policies is that of contract failure: the nearly inevitable situation in which signed contracts with renewable projects do not *all* yield operating facilities on the schedule originally envisioned. We strongly encourage California's policymakers to anticipate and address this risk now, instead of addressing it after the fact by either imposing burdensome noncompliance penalties on utilities or essentially granting the utilities a "free-ride" and forgiving their lack of compliance. The CPUC may specifically wish to consider requiring utilities to "over-procure" renewable energy, in anticipation of some level of contract failure. If the CPUC decides not to require over-procurement, it may instead wish to clarify how it will apply noncompliance penalties and compliance flexibility in the event of contract failure. As experience is gained, we also advise California's regulatory authorities to evaluate how bid deposits, credit requirements, and bid evaluation protocols might be used to minimize the risk of contract failure, while at the same time not overly limiting the number of project bidders.

ESPs and CCAs: After two and half years, it is time to address ESP and CCA compliance, and recent action by the CPUC in this area is encouraging. ESP and CCA compliance will pose special challenges, as their loads may be relatively small, and ESPs and CCAs may not all be in a position to commit to long-term renewable electricity contracts. The overall RPS design in California, with renewable energy procurement plans, advance approval of bid solicitations, PRG review of contracts, and CPUC contract approval, may simply not make sense for ESPs and CCAs. In other states with RPS policies, ESPs have generally complied with the RPS through short-term REC purchases—an option not currently allowed in California. Legislative changes to the California RPS – or else the development of a central procurement agent able to commit to purchases on behalf of ESPs or their customers – may well be necessary.

Supplemental Energy Payments: The existence of SEPs makes the California RPS unique, but less recognized is that SEPs potentially create perverse incentives. Because utility payments are capped at the MPR, utilities may be indifferent to the cost of contracts that exceed the MPR, and may therefore select projects with an undue emphasis on, for example, portfolio fit at the expense of total societal cost. The result may ultimately be higher-cost renewable contracts and a premature draw down of SEP funds. Regulatory approval of renewable energy solicitations and evaluation protocols, PRG oversight, and CPUC contract pre-approval can counteract these incentives, but each results in added complexity. The existence of SEPs also complicates the issue of unbundled RECs (specifically, whether such transactions can receive SEPs), may negatively affect bid prices, and leads to questions over the financeability of state-administered payments to renewable generators. Eliminating the MPR and SEPs, and simply allowing utilities to recover renewable energy costs in retail rates like most other RPS policies, would help solve these problems. We believe the state's policymakers should seriously consider moving in this direction. The primary stated advantage of the MPR-SEP structure – the establishment of a cap in overall program costs – can easily be addressed through other means; many other states, for example, have successfully applied cost caps to RPS policies without a MPR-SEP structure. To avoid unnecessary interruption of a program that is beginning to show signs of working, however, we recommend that the present structure remain in place until a new system if fully operational.