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Decision 11-04-030 April 14, 2011

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

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| Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program. | Rulemaking 08-08-009 (Filed August 21, 2008) |

# DECISION CONDITIONALLY ACCEPTING 2011 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS AND INTEGRATED RESOURCE PLAN SUPPLEMENTS

# DECISION CONDITIONALLY ACCEPTING 2011 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS AND INTEGRATED RESOURCE PLAN SUPPLEMENTS

## 1. Summary

The California Renewables Portfolio Standard (RPS) Program requires that each California electric utility procure, with limited exceptions, an annual minimum quantity of electricity generated from eligible facilities powered by renewable energy resources, with the quantity increasing at least 1% each year and reaching 20% by 2010. To fulfill this requirement, Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) must each prepare an RPS procurement plan (Plan), and update that Plan when directed by the Commission. The Commission is required to review and accept, modify or reject each Plan before commencement of renewables procurement. California Pacific Electric Company, LLC (CalPeco, previously Sierra Pacific Power Company) and PacifiCorp must each file a biennial Integrated Resource Plan (IRP), along with limited supplemental information. In years in which an IRP is not filed, CalPeco and PacifiCorp must each file more comprehensive Supplements. The Commission reviews each IRP and Supplement.

In this decision, we conditionally accept the recent Plans filed by SCE, PG&E, and SDG&E. We also review the Supplements to IRPs filed by CalPeco and PacifiCorp. Important steps we take include:

1. Economic Curtailment: Direct that each utility include provisions for buyer-directed economic curtailment in its Final 2011 Plan.

2. Tradable Renewable Energy Credits: Require that each utility include its intended use of tradable renewable energy credits in its Final 2011 Plan.

3. Other Updates: Direct that each utility include use of recently adopted procurement tools in its Final 2011 Plan.

4. Modify Non-Disclosure Agreements: Require that each utility modify its non-disclosure agreement or confidentiality provisions to permit discussion by not only utilities but also bidders/sellers of the bidding and negotiating process with the Commission and certain others.

5. Schedule: Adopt a schedule for the 2011 solicitation, and a process for initiating the next solicitation.

SCE, PG&E, and SDG&E shall each, within 14 days of the date this order is mailed, file and serve a Final 2011 Plan, with a copy also filed on the Director of the Commission's Energy Division. Each utility shall proceed to use its Final Plan for its RPS program and current solicitation, unless the Final Plan is suspended by the Executive Director or Energy Division Director within 21 days of the date this order is mailed. CalPeco and PacifiCorp shall each continue to use its IRP and Supplement. A more comprehensive summary of requirements for the Final Plans and future Supplements is in Appendix A. The solicitation schedule is in Appendix B.

We continue to employ the presumption that each utility may apply its own reasonable business judgment in running its solicitation, within the parameters we establish and the guidance we provide. Utilities ultimately remain responsible for program implementation, administration and success, within application of flexible compliance criteria. We will later judge the extent of that success, including the degree to which each utility implements Commission orders, elects to take Commission guidance, demonstrates creativity and vigor in program administration and execution, and reaches program targets, goals and requirements. This proceeding remains open.

## 2. Background

The first substantial procurement of non-utility generated electricity in California began in 1979 (Decision (D.) 91109, 3 CPUC2d 1), and resulted in the operation of approximately 11,000 megawatts (MW) of new cogeneration and small power production powerplants, with about 5,000 MW using renewable fuels. Senate Bill (SB) 1078 established goals for seeking additional renewable procurement via the California Renewables Portfolio Standard (RPS) Program effective January 1, 2003.[1]

Several RPS procurement plans (Plans) have been reviewed by the Commission, and implemented under the RPS Program by Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) (collectively the investor-owned utilities or IOUs). On May 29, 2008, we completed the specification of obligations under the RPS Program for Sierra Pacific Power

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[1] Stats. 2002, ch. 516, sec. 3, codified as Pub. Util. Code §§ 399.11, et seq., as amended by (or related to), among others, Assembly Bill (AB) 1969 (Stats. 2006, ch. 731); SB 107 (Stats. 2006, ch. 464); SB 380 (Stats. 2008, ch. 544); SB 32 (Stats. 2009, ch. 328); SB 695 (Stats. 2009, ch. 337). All subsequent code section references are to the Public Utilities Code unless noted otherwise. The RPS Program and code sections referenced herein are those effective on the date of this order. Recently adopted SB 2 (2011-12 First Extraordinary Session, Stats. 2011, ch. 1) further changes the RPS Program and code sections, but those changes do not necessitate a delay in the solicitation authorized by this order.

Company (Sierra, now California Pacific Electric Company, LLC or CalPeco)[2] and PacifiCorp (collectively the multi-jurisdictional utilities or MJUs). This includes the filing by an MJU of a biennial Integrated Resource Plan (IRP) in some years (along with limited supplemental information), and a more comprehensive Supplement to its IRP in other years. (D.08-05-029.)

By Amended Scoping Memo on November 2, 2009, the assigned Commissioner established the scope and schedule for Commission consideration of the next RPS Procurement Plans and IRP Supplements. The Amended Scoping Memo suggested a streamlined approach for presentation and consideration of those documents, consistent with the absence of legislation or Commission-identified issues requiring a comprehensive new Plan. The Amended Scoping Memo also encouraged the procuring utilities to simplify, harmonize, and seek uniformity in processes and documents. It also provided for the filing in some cases of a more comprehensive Plan.

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[2] See D.10-10-017 (conditionally approves the transfer of the California electric distribution system facilities and the Kings Beach Generating Station of Sierra Pacific Power Company to CalPeco). CalPeco may file a pleading if it is no longer an MJU (e.g., no longer prepares biennial IRPs related to multiple jurisdictions) but seeks to be subject to other California RPS requirements (e.g., either those of a large IOU, such as SDG&E, or a small IOU, such as Mountain Utilities).

On December 18, 2009, RPS Procurement Plans were filed by the IOUs.[3] Also on December 18, 2009, PacifiCorp filed a Supplement to its 2008 IRP, and Sierra filed a Supplement reporting no significant changes from its accepted 2009 Supplement to its 2007 IRP. On January 19, 2010, comments were filed by the Commission's Division of Ratepayer Advocates (DRA) and jointly by the California Wind Energy Association and Large-Scale Solar Association (CalWEA/LSA). On January 26, 2010, reply comments were filed by SCE, PG&E, SDG&E, Center for Energy Efficiency and Renewable Technologies (CEERT) and The Utility Reform Network (TURN).

Transmission Ranking Cost Reports (TRCRs) are also a required part of the Plan review process. On January 20, 2010, draft TRCRs were filed. Comments were due by February 10, 2010. No comments were filed.

On February 17, 2010, PG&E and SDG&E filed updated Plans.[4] On April 9, 2010, PG&E, SCE, and SDG&E filed amended Plans with updates related to tradable renewable energy credits (TRECs).[5] On April 23, 2010,

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[3] We refer hereinafter to these Plans as 2011 Plans (even though they were originally filed as 2010 draft Plans) since this decision is reached in 2011, and the solicitation which will result from today's order will be in 2011.

[4] Consistent with the Amended Scoping Memo, motions were filed to permit filing of the updates. Responses and replies to these and subsequent motions to update Plans were filed over the course of the proceeding. The motions were granted by Administrative Law Judge (ALJ) Ruling on February 9, 2011. The responses and replies largely address substantive (not procedural) issues, and, to the extent necessary and appropriate, the substantive issues are addressed in this decision.

[5] On March 11, 2010, the Commission authorized the use of TRECs, and ordered utilities to file and serve amendments to their 2010 RPS Plans to address the use

*Footnote continued on next page*

TURN, DRA, CalWEA/LSA, and Solar Alliance (SA) filed comments. On May 3, 2010, DRA, SDG&E, SCE, PG&E, and CalWEA/LSA filed reply comments.

On June 6, 2010, PG&E filed an amended Plan with updates related to its solar photovoltaic (PV) program.[6] On June 18, 2010, DRA, CalWEA/LSA and L. Jan Reid (Reid) filed comments. On June 25, 2010, PG&E filed reply comments.

On June 12, 2010, SCE amended its Plan to address economic curtailment. This amendment followed an all-party meeting regarding curtailment provisions in RPS Plans held by the assigned Commissioner on May 6, 2010. On July 2, 2010, CalWEA/LSA and Independent Energy Producers Association (IEP) filed responses to SCE's amended Plan. On July 12, 2010, SCE filed a reply.

of TRECs. (See D.10-03-021 Ordering Paragraphs 1, 2, 33.) A schedule for doing so was set by ALJ Ruling dated March 19, 2010. The IOUs were directed to file updates, and MJUs were directed to file either an update or a statement that there would be no change. On April 9, 2010, Sierra and PacifiCorp each filed a notice of no change to their IRPs or Supplements based on TRECs. On May 6, 2010, the Commission stayed D.10-03-021. (See D.10-05-018.) On January 13, 2011, the Commission made limited modifications to, and lifted the stay of, D.10-03-021. (See D.11-01-025.)

[6] On April 22, 2010, the Commission authorized PG&E's solar PV Program. (See D.10-04-052.) By ruling dated May 12, 2010, PG&E was directed to further update its Plan.

On August 24, 2010, IEP and CalWEA filed late comments regarding one item in SCE's Plan.[7] On September 8, 2010, SCE filed timely reply comments, and on September 22, 2010, CEERT filed late reply comments.[8]

Motions for hearing were due January 28, 2010, or later as appropriate. No motions for hearing were filed. No hearing was held.

## 3. Overview of Plan Requirements and Commission Approach

### 3.1. Overview of Plan Requirements

Each utility covered by the RPS Program is required each calendar year to procure, with some exceptions, a minimum quantity of electricity generated from eligible facilities powered by renewable energy resources.[9] This minimum is measured as a percentage of total retail sales and is generally known as the annual procurement target, or APT. Each utility is also required, with some exceptions, to increase its total procurement from eligible renewable energy resources by at least 1% of retail sales per year until it reaches 20%. This is generally known as the incremental procurement target, or IPT, and results in annual incremental growth in the APT. (§ 399.15.) Each utility must, subject to certain flexible

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[7] The one item is SCE's proposal to require that seller's interconnection application provide for full deliverability. This item is described and discussed in Chapter 4.

[8] On September 15, 2010, the ALJ authorized this late filing.

[9] Exceptions include, for example, the use of provisions which allow flexible compliance.

compliance provisions, reach 20% by 2010.[10] Procuring utilities have a three-year flexible compliance window to meet each year's target, thereby potentially allowing a utility until 2013 to meet 2010 targets. Failure to reach an annual target exposes the utility to possible penalty.

Each utility, as part of fulfilling these requirements, must prepare a Plan for the procurement of RPS-eligible energy. The Plan must include but is not limited to (a) an assessment of demand and supply to determine the optimal mix of renewable resources, (b) use of flexible compliance

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[10] While statutes provide for 20% by 2010, a goal of 33% by 2020 has been established in other ways. For example, as early as October 2005, the California Energy Commission (CEC) and this Commission jointly adopted Energy Action Plan II (EAP II) identifying as a key action item the implementation of 33% by 2020 (subject to cost-benefit and risk analysis). (EAP II at 8.) In February 2008, we concluded that retail sellers should be expected to increase RPS procurement each year toward a goal of 33% by 2020 but should not be subject to penalties for failure to procure more than 20% by 2010. (D.08-02-008, Conclusion of Law 13.) On November 17, 2008, the Governor established an RPS target by which all retail sellers shall serve 33% by 2020. (Executive Order (EO) S-14-08.) On December 11, 2008, the California Air Resources Board (CARB) adopted a Scoping Plan for implementation of California's greenhouse gas statute (AB 32; Stats. 2006, ch. 598, codified at Health & Safety Code §§ 38500 et seq.). CARB's Plan includes implementing 33% renewable resources in the electricity sector by 2020. (D.08-12-058 at 6.) On September 15, 2009, the Governor ordered CARB, as part of CARB's implementation of the California Global Warming Solutions Act of 2006 (AB 32), to adopt a regulation consistent with the 33% target established in EO S-14-08. (EO S-21-09.) On September 23, 2010, CARB adopted a 33% renewable energy standard (RES). CARB is finalizing the RES regulations. SDG&E offered to commit, upon the approval of the Sunrise Powerlink Transmission Project (Sunrise), to achieve 33% by 2020. On December 18, 2008, we accepted SDG&E's commitment to reach 33% by 2020, and approved the project. (D.08-12-058 at 260.) Recently adopted SB 1X2 adds a statutory requirement of 33% by 2020.

mechanisms established by the Commission, and (c) a bid solicitation. (§ 399.14(a)(3).)

IOU Plans are subject to Commission review and acceptance, modification or rejection prior to the commencement of renewable resource procurement. (§ 399.14; D.03-06-071.[11]) An IOU must update its Plan when required by the Commission. (§ 399.14.) For MJUs, we review the biennial IRP (with limited supplemental information) and, in years without an IRP, an expanded Supplement to the IRP.[12] (D.08-05-029.) The Commission does not require the MJUs to engage in the same solicitation cycle required of the IOUs. Therefore, the MJUs need not await Commission action before their commencement of renewable resource procurement.

Appendix C contains links to IOU draft Plans and MJU Supplements which we review in this decision.

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[11] Also see D.05-07-039, D.06-05-039, D.07-02-011, D.08-02-008, and D.09-06-018.

[12] All RPS-obligated load serving entities (LSEs) must meet five basic elements of the RPS Program. These are: (1) 20% by 2010; (2) increase annual procurement by 1%; (3) report on progress; (4) use of flexible compliance; and (5) uniform penalty provisions. The LSEs include not only large utilities but also MJUs, small utilities, electric service providers (ESPs) and community choice aggregators (CCAs). The MJUs (Sierra and PacifiCorp) must file IRPs and certain Supplements to IRPs. ESPs must file annual procurement plans. (See D.11-01-026.) The small utilities (i.e., Bear Valley, Mountain Utilities) and CCAs are not required by the Commission to file annual procurement plans. (See D.06-10-019 and D.08-05-029.)

### 3.2. Overview of Commission Approach

We have followed an approach of "flexibility with accountability" as we allow utilities to fulfill their duties under the Program. That is, we have granted RPS-obligated utilities considerable flexibility in the way they satisfy RPS Program goals. In exchange, each utility must meet its RPS Program targets, within application of flexible compliance criteria, subject to penalties for unexcused failures to meet targets.

Our responsibility includes accepting, rejecting or modifying IOU Plans (or updates to those Plans) before solicitations may begin. We also review the MJU IRPs and IRP Supplements. We do not, however, write any Plan, IRP or Supplement, or dictate with precise detail the specific language of any Plan, IRP or Supplement. Nor do we micromanage what is in the Plan, IRP or Supplement. Rather, each utility has considerable flexibility to develop and propose its own Plan, IRP, and Supplement. Our review is at a reasonably high level. Similarly, we do not take over the procurement process. Each utility is ultimately responsible for achieving successful procurement using its Plan, IRP or Supplement pursuant to, and consistent with, the RPS Program.

Our responsibility also includes reviewing the results of solicitations. It includes accepting or rejecting proposed contracts, based on consistency with approved Plans, when the contracts are submitted for approval. (§ 399.14(d).) The Plans accepted herein are a fundamental, but not necessarily the only, part of that review.[13] Similarly, the Supplements

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[13] The review is also described in D.06-05-039, D.07-02-011, and D.09-06-018.

will be a fundamental, but not necessarily the only, consideration when reviewing an MJU's compliance with RPS Program obligations.

We have conditionally accepted prior Plans, provided guidance, taken steps to broaden and enhance the quantity and quality of RPS bids, and improved the contracting process.[14] We continue to do so here. We do not repeat existing Commission directions, requirements, and guidance. Rather, all existing directions and guidance remain unchanged unless specifically addressed otherwise herein.

In this order, we discuss limited issues which require our attention before the next solicitation. We first address several issues common to most if not all Plans. We then examine issues specific to a particular Plan or Supplement. We conclude by adopting the schedule for 2011 Plan solicitations, and the process for considering 2012 Plans.

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[14] For example, we require IOU Plans to: (a) include consideration of proposals with delivery points anywhere in California; (b) incorporate reasonable margins of safety (e.g., allowing for some possible project delays or failures while still meeting Program targets); (c) include interest on deposits; and (d) clearly state the evaluation criteria used in the least-cost/best-fit (LCBF) selection process. We have also (a) adopted revised standard terms and conditions (STCs) for model contracts to increase contracting flexibility; (b) included solicitation of short-term contracts within approved Plans to promote flexibility; (c) recognized individual utility initiative as part of the utility's Plan in order to facilitate creativity, while accepting the utility's proposal to defer certain decisions (e.g., SCE Biomass Program); (d) permitted eligible contracts to be treated as a pool rather than require that the earmarking process identify a specific contract for future satisfaction of a deficit; (e) addressed issues unique to the Sunrise project; (f) adopted a project viability evaluation methodology and required its use; and (g) required that an IOU permit bids of any duration (e.g., in excess of 20 years) in the language it uses in its request for proposal (consistent with STC 5). (See, for example, D.06-05-039, D.07-02-011, D.07-11-025, D.08-02-008, and D.09-06-018.)

## 4. Issues Common to All Plans

We address the following issues common to most, if not all Plans:

- Buyer-Directed Economic Curtailment
- Integration Cost Adders
- Tradable Renewable Energy Credits (TRECs)
- Sunrise/Imperial Valley Remedial Measures
- California Independent System Operator (CAISO) Standard Capacity Product (SCP)
- Pilot Programs for Preapproval of Short-Term Contracts
- Plan Organization and Standardization
- Other Updates
- MJU Supplemental Filing Date
- Non-Disclosure Agreements

### 4.1. Buyer-Directed Economic Curtailment

The CAISO recently implemented its Market Redesign and Technology Upgrade (MRTU). MRTU uses markets and market-determined prices to schedule and dispatch generation resources. In particular, it uses Locational Marginal Prices (LMPs) as price signals reflecting electricity supply and demand in multiple locations. Over time, LMPs could also give price signals that influence project location.

To address MRTU issues, SCE and PG&E propose modifying pro forma (model) contract terms and solicitation protocols. SCE and PG&E propose terms that would allow the utility, as buyer and scheduling coordinator, to decline procurement from a renewable generator if the day-ahead price makes the delivery uneconomic. We refer to this as buyer-directed economic curtailment, or economic curtailment.[15] We address three economic curtailment issues presented by parties:

1. Pre-2011 contract interpretation;
2. 2011 pro forma contracts; and
3. Requirement that project be fully deliverable.

#### 4.1.1. Pre-2011 Contract Interpretation

In its draft 2011 Plan, SCE asserts that its prior pro forma contracts allow SCE to direct curtailment of an RPS project at the request of either the CAISO or SCE.[16] SCE also says it has the right to withhold payment to the seller for energy that the facility could have delivered but for the curtailment ordered by SCE.

CalWEA/LSA disagree, asserting that prior pro forma contracts do not allow unlimited curtailment by SCE for economic or other reasons. They claim that SCE's interpretation jeopardizes the ability of developers to find project financing.[17] TURN, IEP, and CEERT agree. In addition, TURN and IEP say that SCE's interpretation could result in significant contract price increases to cover the risk of substantial curtailment.[18]

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[15] No party disputes contract terms and conditions that allow the buyer to direct reduced project deliveries when instructed by the CAISO for system reliability, safety, stability, or similar non-economic reasons. As a result, this section does not address non-economic CAISO-directed curtailment.

[16] December 18, 2009 Plan at 50.

[17] January 19, 2010 Comments at 2.

[18] TURN January 26, 2010 Reply Comments at 1.

CEERT states that SCE's interpretation is inconsistent with prior power purchase agreements (PPAs), prior Plans, and Commission decisions.[19]

We decline to interpret terms of executed contracts. Rather, disputes over terms in executed contracts are subject to the dispute resolution provisions of the contract. Parties should use those provisions.

Some pre-2011 pro forma contracts may not yet be executed, but might be the subject of ongoing negotiations. If so, buyer and seller may negotiate a mutually acceptable solution regarding this issue in light of SCE's statements. We need not disturb the negotiation process.

We note, however, that our approval of prior Plans and pro forma contracts has been, and is, in the context of "flexibility with accountability." (D.09-06-018 at 9.) Each utility is "ultimately responsible for proposing and executing reasonable Plans that achieve RPS targets." (*Id*. at 53.) This responsibility includes contract execution and ongoing contract administration. SCE's interpretation and enforcement of prior pro forma and executed contracts is a factor in that administration. If SCE fails to execute contracts or a contract fails due to unreasonable administration by SCE, with SCE thereby failing to reach its program targets (e.g., 20% by 2010), SCE is subject to being held accountable. This includes the potential of SCE paying penalties for failing to reach targets.[20]

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[19] CEERT January 26, 2010 Reply Comments at 1.

[20] D.03-12-065 Attachment A, adopting a modification of D.03-06-071 at 51.

#### 4.1.2. 2011 Pro Forma Contracts

PG&E and SCE propose 2011 pro forma contracts allowing economic curtailment. SDG&E makes no such proposal. For the reasons explained below, we direct that all three IOUs include economic curtailment provisions in their Final 2011 Plans, and reveal limited specific congestion cost information to the extent used in LCBF evaluations. We first briefly describe the proposals.

PG&E proposes economic curtailment up to five percent of the project's expected annual generation per year, with PG&E paying the seller the full contract price for curtailed energy. The reduced generation, however, may result in the seller losing certain tax advantages (i.e., production tax credits or PTC). PG&E does not propose reimbursement for the lost PTCs.

SCE first proposed unbounded economic curtailment. SCE modified its proposal based on parties' comments. As modified, SCE proposes economic curtailment without compensation (and without reimbursement for lost PTCs) up to a pre-determined, negotiated number of hours capped at between 50 and 200 per year. Economic curtailment in excess of the cap is to be compensated by SCE at the contract price plus the value of any lost PTCs. At the end of the contract SCE would have the option to buy generation equal to twice the total amount that was curtailed over the life of the contract in excess of the cap at 50 percent of the contract price. This option could be exercised for up to two years past the conclusion of the original contract term.

SDG&E proposes no change from its 2009 pro forma contract. As a result, SDG&E could not exercise economic curtailment in response to MRTU price-based scheduling and dispatch.

Parties take a range of positions largely in opposition to economic curtailment. For example, CalWEA, LSA, and IEP oppose SCE's proposal, saying it is too complex and would result in higher contract prices than the proposals of either PG&E or SDG&E. TURN joins the opposition saying SCE's proposal would be more costly to ratepayers than SCE simply accepting actual curtailment risk.

CalWEA, LSA, and IEP seek a simple approach. For example, IEP suggests allowing economic curtailment without compensation up to 20 hours per year. Alternatively, IEP suggests supporting the proposal of SDG&E or PG&E because either one is simpler, while being financeable at less cost, than SCE's proposal. CalWEA and LSA recommend the Commission reject SCE's proposal, with a requirement that SCE adopt a modified version of PG&E's proposal.

We determine it is reasonable for the pro forma contract of each IOU to include provisions for economic curtailment. We reach this conclusion because MRTU has the potential of significantly changing the way generation resources are scheduled, dispatched and located. RPS contracts must reasonably reflect the CAISO's new economic approach. Failure to do so could undermine the ability of MRTU to optimally use price signals for those economic purposes.

It is clear that the impact on stakeholders differs under the proposals of PG&E and SCE, but we are unable to determine an optimal approach. Parties fail to present estimates of the likely locations or amounts of curtailment over the contract duration, the likely impact on contract prices resulting from various proposals, or any other facts or compelling argument to differentiate the impact of alternative economic curtailment approaches on different stakeholders. Without facts or more compelling argument, we decline to simply pick one.

All parties agree, however, that the proposals of both PG&E and SCE (as modified) are financeable because, by establishing specific limits, each bounds the developer's economic curtailment risk. Moreover, each proposal shares congestion cost risk between developers and ratepayers; provides economic information to developers, sellers and IOU buyers; and is negotiable between buyer and seller before final contract execution.[21]

As a result, we do not pick one approach but require an economic curtailment provision in the Final 2011 Plans filed by each IOU, including SDG&E. Consistent with our approach of flexibility with accountability, SCE may use its preferred approach, PG&E may use its preferred approach (with one modification required below), and SDG&E may develop one.[22]

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[21] Non-modifiable standard terms and conditions are limited to four, and do not include economic curtailment terms and conditions. (See D.08-04-009.)

[22] SDG&E's economic curtailment provision must be consistent with the factors discussed herein, including that it be financeable (e.g., reasonably bound the developer risk, such as by a maximum number of curtailment hours or other device); and it must reasonably share the cost and risk of curtailment between stakeholders (e.g., so developers have an incentive to minimize congestion costs when making decisions on project site, interconnection and operation, while potential ratepayer cost is not unlimited).

We also address congestion costs as part of the treatment of economic curtailment. We do this within the framework of MRTU's use of price signals (LMPs) to schedule, dispatch and potentially locate generation resources based on supply and demand, along with other potential costs related to supply and demand imbalances. SDG&E reports that it assesses congestion within its LCBF evaluation, and PG&E commits to doing so similar to its past practice.[23] This is reasonable, and we will require SCE to similarly incorporate assessment of congestion costs in its 2011 LCBF evaluations.

SCE should, as a result, include modifications to its LCBF methodology as part of its Final 2011 Plan filed pursuant to this order. The modifications should clearly incorporate and explain its economic curtailment provisions and use of congestion costs. SDG&E and PG&E should modify their LCBF descriptions as necessary to make their economic curtailment provisions and use of congestion costs clear. Further, to the extent an IOU uses specific congestion cost values in its LCBF protocol, the IOU should make those values available to bidders as part of making the LCBF methodology transparent.

Finally, as recommended by CalWEA/LSA, we require PG&E to modify its payment provisions. As modified, PG&E will pay a seller for curtailment even when that economic curtailment is initiated by an entity

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[23] SDG&E already includes congestion cost adders in its LCBF methodology. (April 9, 2010 Further Amended Draft 2010 Renewable Procurement Plan, Appendix C at 3.) PG&E used LMP multipliers in prior RPS RFO evaluations, and says it will do so for the 2011 solicitation. (March 3, 2011 Comments on Proposed Decision (PD) at 6.)

other than PG&E (such as the CAISO). We do this because CalWEA/LSA correctly point out that the curtailment instruction may be the result of PG&E actions or omissions. We agree with CalWEA/LSA that PG&E's approach to economic curtailments would thereby effectively not be limited to five percent of expected annual output. Therefore, we apply the five percent limit to all economic curtailment whether or not initiated by PG&E.[24]

We do not, however, require PG&E to compensate the seller for lost PTCs, as recommended by CalWEA/LSA. We agree with PG&E that it is reasonable for sellers to bear some of the curtailment risk. Further, PG&E correctly points out that determining the amount of the lost PTC is complex and time-consuming. While SCE agrees to do so, we will not require this of PG&E.

#### 4.1.3. Fully Deliverable

In its amended Plan, SCE explains that the Large Generator Interconnection Agreement gives sellers two deliverability options from which to choose: energy-only or fully deliverable. SCE proposes that sellers be required to be fully deliverable. We decline to adopt this recommendation. We first briefly explain the two deliverability options.

Energy-only projects are only required to pay the costs necessary for the project to interconnect to the network. Fully deliverable projects must

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[24] The limit does not apply to non-economic curtailment (e.g., for system reliability, safety, stability).

also pay costs to ensure deliverability.[25] The benefits of being fully deliverable include that the project can count toward an IOU's resource adequacy (RA) requirements, along with being obligated to pay its portion of any deliverability upgrade costs. CAISO decisions about which projects to curtail, however, are not affected by the project's deliverability interconnection type.

SCE proposes a fully deliverable requirement so that the project counts towards SCE's RA requirements. In support, SCE argues that energy-only interconnections expose the grid to greater risks of congestion and over-generation since these projects do not pay for necessary deliverability upgrades to avoid congestion. Further, SCE contends that full deliverability requires the project pay its share of deliverability upgrade costs. SCE suggests the Commission require that all IOUs adopt this provision so that projects selling to other buyers also share deliverability upgrade costs. IEP/CalWEA and CEERT oppose SCE's proposal.

We decline to adopt SCE's proposal. SCE expresses a legitimate concern that allowing energy-only projects to participate in RPS

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[25] The CAISO tariff differentiates delivery status as energy-only versus full capacity. (CAISO Fifth Replacement Tariff, December 20, 2010, Appendix A, Master Definition Supplement at 810, 817.) Projects with energy-only deliverability status must pay costs for (a) direct interconnection facilities (non-network upgrades to the nearest point on the network) and (b) network reliability upgrades. Projects with full capacity deliverability status must pay those costs plus facility costs to satisfy deliverability criteria. A project with full capacity deliverability status can deliver the facility's full output to the CAISO during a variety of stressed system conditions.

solicitations may increase the risk of congestion (and negative LMP prices) because those projects do not help fund deliverability upgrades. However, it is not clear that the cost to build additional facilities (e.g., transmission for deliverability) will be lower than costs related to curtailment. In addition, we address congestion cost concerns and mitigate ratepayer risk in other ways in this decision (e.g., contract terms in 2011 Plans for economic curtailment, LCBF treatment of congestion costs). This will allow IOUs to assess congestion costs as part of a bid's value and encourage developers to seek project sites with fewer potential congestion costs, without foregoing a viable interconnection option currently permitted by the CAISO.

Moreover, IOUs incorporate RA adequacy into their LCBF methodologies. Thus, IOUs are able to assess the RA value differential, if any, of a project interconnecting at energy-only versus full deliverability. The RA treatment in each IOU's LCBF methodology should be clearly explained, however. Thus, each IOU should modify its LCBF description, as necessary, to make its treatment of RA, and use of RA adders, clear to bidders as part of making the LCBF methodology transparent.

### 4.2. Integration Cost Adders

Integration costs are costs associated with ancillary services needed for real time balancing of the CAISO transmission system from instability caused by unexpected fluctuations in generation or load. SCE and SDG&E propose the use of non-zero integration cost adders in draft 2010 Plans as part of their LCBF evaluation of bids. In particular, SCE proposes use of integration cost adders that will be developed based on multiple integration cost studies.[26] SDG&E proposes to use cost adders that will be determined at a later point in consultation with its independent evaluator (IE).[27] CalWEA, LSA, DRA, and TURN oppose these proposals.

We decline to adopt non-zero integration cost adders in this decision. We have previously rejected proposals for non-zero integration cost adders.[28] Nothing presented here changes our view. IOUs must exclude language in Final 2011 Plans that would incorporate use of non-zero integration cost adders, including their use in LCBF evaluation of bids.

Moreover, we said before that such costs, if any, need to be developed with public review and comment.[29] CalWEA, LSA and TURN argue that an adder should only be used if it is developed in a public forum and, in addition, with Commission supervision.[30] We agree. We are currently assessing renewable integration needs and costs in another proceeding (Rulemaking (R.) 10-05-006). If an adder is developed in that proceeding, then each IOU may file an advice letter seeking to amend its 2011 Plan for the purpose of using that adder in its LCBF evaluations.

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[26] June 17, 2010 Second Amended 2010 RPS Procurement Plan at 47.

[27] April 9, 2010 Further Amended Draft 2010 Renewable Procurement Plan, Appendix C (LCBF Process) at 3.

[28] D.07-02-011 at 56; D.08-02-008 at 44.

[29] D.08-02-008 at 45.

[30] January 19, 2010 CalWEA/LSA Comments at 16; January 26, 2010 TURN Reply Comments at 5.

### 4.3. TRECs

IOUs include discussion of the use of TRECs in their draft Plans, generally seeking use of TRECs but conditioned on a future Commission order authorizing that use. DRA recommends that the Commission reject inclusion of TRECs in these Plans. In support, DRA says the Commission has not reached a final decision on the use of TRECs. DRA also notes that we ordered the removal of TREC discussion in the 2009 Plans. (D.09-06-018 at 37-39.) Reid similarly supports removal of references to TRECs in amended Plans and solicitation protocols.

Subsequent to parties' comments here, we lifted the stay of D.10-03-021. We now permit the use of TRECs for RPS compliance. (D.11-01-025.) Therefore, it is appropriate for 2011 Plans to include IOUs' intended use of TRECs. Final Plans filed pursuant to this decision should include each IOU's planned use in a manner that complies with the authorization prescribed in D.11-01-025. MJUs previously reported no change in their IRPs or Supplements based on our March 2010 TREC order. MJUs should file an Amended Supplement, however, if their planned use of TRECs is now changed as a result of our January 2011 order.

### 4.4. Sunrise/Imperial Valley Remedial Measures

We required IOUs to hold a special Imperial Valley bidders conference, and perform specific proposal and project monitoring, as part of the 2009 RPS solicitation. (See D.09-06-018.) We did this in order to provide all reasonable opportunities for optimal use of the Sunrise transmission project. We declined to adopt automatic additional measures relative to Sunrise for the 2010 solicitation, but stated that:

> " … we will consider remedial measures if future evidence shows the LCBF methodology fails to properly value Imperial Valley resources and their unique access to transmission, or that there are other infirmities. Those measures might include automatic shortlisting, a special bid evaluation metric, special solicitation, or other remedies a party may propose. The expense and environmental consequences of Sunrise, just as with any significant infrastructure project, demand nothing less. We will not hesitate to use all regulatory tools at our disposal so that reasonable, cost-effective renewable resources enabled by Sunrise are developed. (See D.08-12-058 at 263.)" (D.09-06-018 at 18.)

The Amended Scoping Memo specifically directed IOUs to address this issue.

All three IOUs report robust Imperial Valley results from the 2009 solicitation. PG&E says it received a significant volume of offers from projects that would interconnect to the grid in Imperial Valley, and the number of bids for development in the Imperial Valley relative to resource development potential for the area was roughly the same proportion observed for renewable bids throughout the rest of PG&E's territory. SDG&E states that the number of offers it received from Imperial Valley was many times more MW than can flow over the Sunrise Powerlink. According to IOUs, the Commission's desire that renewable resources take full advantage of the Sunrise project is being met, and remedial measures are not needed in the 2011 Plans. No party comments to the contrary.

We agree. We are encouraged by the robust response, and confident that IOUs will select all reasonable bids within the LCBF process. We decline to order any remedial measures, but continue specific monitoring of Imperial Valley proposals and projects.[31]

SDG&E states that it plans to host another bidder's conference in the Imperial Valley regardless of whether it is ordered to do so, believing that further utility (buyer) outreach will help increase industry knowledge and, ultimately, the quality of offers. We have commended utilities for innovative work in the past, and we do so here regarding SDG&E's planned outreach and initiative.[32] We encourage all three IOUs to do outreach, and take all reasonable and necessary action to secure optimal RPS development and reach RPS targets. This should include special Imperial Valley bidder's conferences, when useful, to continue to ensure robust response in this important region.

### 4.5. CAISO Standard Capacity Product

The SCP is a product to reduce transaction costs associated with buying, selling and trading capacity to meet RA requirements. It reduces transaction costs by standardizing the obligations of RA providers. In particular, scheduling coordinators are subject, under CAISO Tariff § 40.9, to charges for non-availability or incentive payments for availability.

SCE, PG&E, and SDG&E propose allocating the benefits and risks of the CAISO's SCP to sellers. CalWEA and LSA recommend that the

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[31] Regarding specific monitoring, see D.09-06-018 at 14; and Appendix A at A-1, Item 1.b.

[32] For example, we commended PG&E for its proposal to include joint development and ownership in its 2009 Plan, and SCE for its RPS Standard Contract Program. (See D.09-06-018 at 3, 48-52, 59-62.)

Commission reject the proposed allocation of risks, asserting it is premature to do so pending final CAISO decisions and, once final, involves complicated implementation details. IOUs respond in opposition to the recommendation of CalWEA and LSA. We adopt IOUs' proposals.

IOUs convincingly show that the proposals allocate not just the burdens but also the benefits to sellers. This is a balanced approach. Moreover, implementation details are distinct from the allocation of benefits and burdens. It is generators rather than IOUs that control facility operation and have the ability to mitigate potential penalties. Allocating potential penalties to the party who is best positioned to mitigate penalties gives that party the incentive to operate optimally.

If the IOUs' proposal is adopted, CalWEA and LSA recommend modification of IOU model PPAs so that the seller's obligation to supply capacity for RA purposes would be optional. This modification is unnecessary. Contract terms (except for limited non-modifiable standard terms and conditions) are subject to negotiation. Bidders may submit bids with a proposal to modify contract terms related to RA (including these changes on a bidder's proposed term sheet summarizing all major proposed changes).[33]

Finally, CalWEA and LSA argue that allocation of risks relative to the SCP duplicates existing incentives. This occurs because compensation for capacity is included in the all-in energy payment. The generator is provided an incentive to provide capacity when the all-in rate includes a

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[33] See discussion of term sheet as part of PG&E proposed changes summarized in Appendix D.

capacity component, and fails to receive this capacity payment when the generator does not operate during those periods (for either a planned or unplanned outage). An SCP penalty for failure to provide resource adequacy value penalizes the generator a second time according to CalWEA and LSA.

We agree, but are not convinced that this merits elimination of the capacity portion of the all-in energy payment. It is reasonable that IOUs reflect the full balance of CAISO provisions in the contract, but generators may pursue relief from duplicative incentives, if any, created by the CAISO (or the Federal Energy Regulatory Commission (FERC) upon review of CAISO action). Finally, if CAISO and FERC do not agree these incentives are duplicative, the bidder may seek to negotiate a different result with the IOU (relying on competition between IOUs to secure an optimal and just outcome).

Thus, IOUs may include allocation of both the benefits and risks of the CAISO SCP to sellers.

### 4.6. Pilot Program for Preapproval of Short-Term Contracts

Last year, as part of their 2009 draft Plans, SCE and PG&E requested authorization for programs permitting preapproval for certain quantities of RPS contracts. We denied those requests in favor of an RPS contract mechanism for simplified, streamlined, fast-track review of short-term contracts. We did so because the adopted mechanism addressed the fundamental goals sought by SCE and PG&E.[34]

As part of their 2010 draft Plans, all three IOUs propose pilot programs for transactions involving short-term deliveries. PG&E and SCE propose similar programs, wherein 1 percent of current year retail load is preapproved for procurement at certain market valuations during the next five years for contracts with durations up to five years.[35] SDG&E proposes a similar program capped at 1500 gigawatt-hours (gWh). According to the IOUs, the proposals are modeled after the IOUs' procurement authority for conventional power.[36] Under these pilot programs, any contract meeting specified criteria (e.g., price cap, total cost cap, energy amount, duration) would be deemed per se reasonable and preapproved for cost recovery from ratepayers.

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[34] D.09-06-018 at 54-55, 57-59; D.09-06-050 at 26-28. We said that PG&E was free to make a new proposal with its 2010 Plan if, after experience with the fast-track procedures, PG&E was still interested in proposing something else. (D.09-06-050 at 27 (footnote 34), 31.)

[35] The volume would be cumulative over the five years, resulting in preapproval of 5% of bundled sales over the five years of the program.

[36] AB 57 Procurement Plans (§ 454.5). See, for example, D.04-12-048 (permitting an IOU to enter into contracts under five years in length without Commission preapproval); D.07-12-052 (permitting an IOU to execute a contract under five years in length without Commission preapproval provided that the procurement complies with a procurement limit methodology). On June 2, 2010, the Commission's Energy Division filed a Procurement Policy Manual. The Introduction (at 1-1) states that the Manual presents "all of the requirements and guidance provided by the Commission to its jurisdictional entities under PU Codes 380, 454.5, and 399.11-399.20. This Manual constitutes the upfront and

*Footnote continued on next page*

DRA and TURN oppose the pilot programs. We decline to adopt IOUs' proposals for the following reasons.

We have inadequate evidence that the system we adopted in June 2009 does not work, cannot work, or cannot be reasonably modified, if necessary. That system was adopted after careful deliberation and the balancing of many competing interests and needs. We encourage IOUs to be more creative and vigorous in seeking authorization for short-term opportunities under our adopted system for fast-track approvals, if short-term transactions are in fact appropriate, desirable, and reasonable.

SCE proposes that we retain our existing fast-track preapproval process but also authorize SCE's pilot program, arguing that there is nothing that prevents the Commission from permitting more than one option for fast-track approval of short-term contracts. We decline to increase the complexity of an already complex program by layering on multiple options to accomplish the same objective.

Most troubling with IOU-proposed pilot programs is the lack of limit and specificity on price and cost. For example, PG&E proposes that it establish both price and revenue requirement caps, but fails to provide adequate information to establish reasonable numbers or process.

SCE proposes a confidential preapproved total cost limit set annually and calculated by SCE using a formula, but fails to convincingly show its formula is reasonable. SCE also proposes a "maximum valuation metric" for each contract. SCE says the "IOU would set a renewable

achievable standards and criteria envisioned by the California State Legislature in Assembly Bill (AB) 57."

premium-based, maximum valuation metric … [and] will share this maximum valuation metric and methodology for setting the maximum valuation metric with its PRG [Procurement Review Group] and the Energy Division."[37] That is, SCE's proposal delegates reasonableness determination to SCE (who will share the information with the PRG and Energy Division) for potentially hundreds of millions of dollars. While we might later be convinced this proposal is reasonable, SCE does not now present sufficient evidence to demonstrate the reasonableness of this approach.[38]

SDG&E says the price for its preapproved contracts will not exceed a price cap, and "SDG&E will work with its IE to determine this pricing cap on an annual basis and brief the Energy Division and its PRG on the pricing cap."[39] SDG&E's proposal would delegate reasonableness determination to SDG&E and its IE (with a briefing to the PRG and Energy Division) for potentially hundreds of millions of dollars. Again, while we

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[37] June 17, 2010 Second Amended 2010 Written Plan at 35.

[38] SCE does not present an example of its "maximum valuation metric" or show how it compares with recent experience. SCE says that "under no circumstance would the maximum valuation metric exceed the reasonable premium of the last marginal proposal received from the most recent RPS solicitation short list." (*Id.*) We are not convinced this is reasonable. For example, we are not comfortable allowing SCE to determine what is or is not the "last marginal proposal." Nor are we sure that any particular solicitation, or all solicitations, will result in reasonable results, or that the "last marginal proposal" will, in any or all cases, be reasonable. SCE provides no data from past solicitations of its "last marginal proposal" to demonstrate the selection process or the value.

[39] April 9, 2010 Further Amended Draft 2010 Renewable Procurement Plan at 13.

might later be convinced this approach is reasonable, SDG&E does not now present sufficient evidence to demonstrate the reasonableness of this approach.

In support of the pilot program proposals, the IOUs note that these contracts are subject to review in Energy Resource Recovery Account (ERRA) proceedings. Contracts engaged in accordance with pilot program guidelines, however, would, under the proposal, be per se reasonable, and contract terms (including payments made by the IOU) would be deemed approved by the Commission and recoverable in rates. Commission review is limited to an IOU's administration of the transaction. The pilot programs, as proposed, would establish a Commission review and administration process that does not adequately fulfill the Commission's duty to determine whether the results are just and reasonable.

The IOUs contend that they need more flexibility to capture short-term, fleeting market opportunities to meet near-term RPS goals in the face of competition from other LSEs, including ESPs and municipal utilities. IOUs also note that renewable energy is a preferred resource and the rules allowing preapproval of short-term transactions for renewable energy should be simpler—not more complex and restrictive—than the rules applicable to procurement of resources lower in the loading order. We agree that IOUs must have flexibility in the face of competition, and the rules for procurement of resources higher in the loading order should generally not be more complex and restrictive than those for resources lower in the loading order.

We are not opposed to a modified or simpler system than the one adopted in June 2009. We specifically noted that PG&E was free to make a proposal in its 2010 Plan, but only after experience with our adopted simplified, fast-track procedure. (D.09-06-050 at 27, 31.) For the reasons explained above, we are simply not convinced that the pilot programs proposed by IOUs are reasonable.

Nonetheless, we are committed to ensuring that IOUs have a reasonable chance to capture short-term, fleeting opportunities while being able to optimally compete against each other and other LSEs. We encourage IOUs to continue to consider and propose refinements, based on experience with our adopted fast-track procedures and the market.

### 4.7. Plan Organization and Standardization

As we have said in each of the last several years, we continue to note that each Plan is complex, with many attachments that are not easy to assess and use.[40] In particular, the form and format of the attached solicitation documents (e.g., Protocol, Request for Proposal (RFP), Request for Offer (RFO)) differ between IOUs, as do the various related forms and model contracts. We remain unconvinced that such complexity is necessary, and we continue to encourage IOUs to seek incremental improvements in standardization and uniformity.

We noted progress made in the 2009 Plans. (D.09-06-018 at 52.) The Amended Scoping Memo encouraged the IOUs to make further progress, particularly in making their three 2010 draft Plans reasonably uniform. IOUs report that the relatively brief time between the issuance of the

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[40] See, for example, D.08-02-008 at 35-38; D.09-06-018 at 52-53.

Amended Scoping Memo and the deadline to file draft 2010 Plans required that they limit and focus their efforts.

We appreciate the IOUs' coordination and focused efforts during that brief time.[41] Our request for additional standardization, streamlining, uniformity, and coordination, however, is not limited to their work only after release of the next Scoping Memo. Rather, we encourage increased standardization in form and format to the fullest extent reasonable beginning now. As we said in 2008:

> … the additional time spent 'up front' should be small compared to the time savings for the entire remainder of the process, including the Commission's time in reviewing endlessly different contracts. Additional uniformity will make the overall RPS structure more transparent, efficient and competitive. It may also promote desirable simplicity in a relatively complex Program. (D.08-02-008 at 38.)

IOUs should begin coordinating now on the form and format of the 2012 Plans, including solicitation protocols, contracts, attachments, and other documents. In particular, we encourage the three IOUs to consider proposing one standard contract that can be preapproved by the Commission. One standard, preapproved contract that can be executed by buyers and sellers will help facilitate speedy and certain Commission review and approval. Negotiated contracts always remain an option, but individualized and unique contracts will continue to take a greater amount

[41] For example, IOUs report that they focused on a uniform proposed schedule, a Commission process for approval of RPS contract amendments, and advance authority to procure short-term contracts.

of staff time for review, and will typically reduce the certainty and slow the process of obtaining approval.

### 4.8. Other Updates

Several events have occurred that may not be fully reflected in IOU Plans. For example, in December 2010 we adopted the Renewable Auction Mechanism (RAM). RAM is a tool for IOUs to procure up to 1,000 MW RPS resources from projects up to 20 MW in size. (D.10-12-048.)

In December 2010, we also adopted implementation details for PG&E's solar PV program. (Resolution E-4368; D.10-04-052.) In September 2010 we authorized SDG&E to undertake a solar PV program. (D.10-09-016.) SCE has now conducted its first solar PV procurement. (D.09-06-049; Resolution E-4299.)

In December 2010, we also adopted a qualifying facility (QF) settlement agreement that addresses small power producers—including RPS facilities—up to 20 MW. (D.10-12-035.)

IOU RPS Procurement Plans are the vehicle for an IOU, in one document, to explain to all stakeholders how the IOU plans to achieve state-mandated RPS targets and goals. To achieve this objective, each Plan must be complete and comprehensive. We require that each Plan address and include all procurement options and tools that an IOU will use to reach RPS targets and goals, including utility-owned generation.

Therefore, IOUs should include these and any other similar items in Final 2011 Plans filed pursuant to this decision to ensure that the filed Plans are complete, comprehensive and up-to-date. Among other things, the resulting contracts can then be judged based on consistency with the accepted RPS Plan, and the energy can be included toward RPS targets and goals (e.g., 20% by 2010, 33% by 2020). We noted this same thing with respect to SCE's RPS Standard Contract Program, and do so again here. (D.08-02-008 at 44; D.09-06-018 at 61-62.)

### 4.9. MJU Supplemental Filing Date

MJUs propose a change in the current annual supplemental filing date. We make the change.[42]

The current schedule requires that MJUs file an IRP with us when one is also filed with other jurisdictions, along with supplement to address California-specific issues within 30 days thereafter. In years in which an IRP is not filed, MJUs must file a Comprehensive IRP Supplement at the same time as IOUs file their RPS Plans.

MJUs say the lack of a fixed filing date for Comprehensive Supplements in non-IRP years creates a logistical challenge, while a set filing schedule would allow the MJU to more efficiently plan and execute its non-IRP year supplement. MJUs ask for a date of July 15, which Sierra says will dovetail well with filing dates applicable to submissions made at the Public Utilities Commission of Nevada. We agree. This does not relieve an MJU from also responding to requests for information at any time by the Commission, including the assigned Commissioner, ALJ, and staff.

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[42] MJUs note that the proposal is in relationship to the schedule set in D.08-05-029.

### 4.10. Non-Disclosure Agreement

CalWEA/LSA recommend that non-disclosure agreements (NDA), or confidentiality provisions, in each Plan be modified to permit discussion by bidders and sellers of the bidding and PPA negotiating process with the Commission and certain other entities.[43] In support, CalWEA/LSA assert that the NDAs and confidentiality provisions allow each IOU to disclose confidential information to multiple agencies or entities (e.g., PRG, IE, Commission, CEC, CAISO) but foreclose bidders/sellers from doing the same. CalWEA/LSA recommend modification of these materials in order to provide the opportunity for bidders/sellers to discuss RPS process with the Commission, its staff, PRGs and IEs.

TURN strongly supports CalWEA/LSA. SDG&E does not oppose allowing disclosure of information by bidders/sellers to the Commission, but says disclosure limitations imposed by SDG&E on itself must apply equally to bidders/sellers. PG&E and SCE oppose disclosure.[44]

We order IOUs to modify their NDAs, or confidentiality provisions, to permit disclosures to the extent described herein. We do so because good decision-making requires consideration of complete information

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[43] January 19, 2010 Comments of CalWEA/LSA at 14-16. For SCE's NDA see June 2010 Second Amended Plan, Attachment 2-10, Form of Seller's Proposal, Exhibits D-1 and D-2. For PG&E's Confidentiality Agreement see June 2, 2010 Solicitation Protocol, Attachment G. For SDG&E's Confidentiality provisions see April 9, 2010 Further Amended Plan, Attachment 1, Appendix A § 11.0.

[44] PG&E initially did not oppose disclosure of confidential information by bidders/sellers to the Commission and its staff, but opposed disclosure to the PRG. (January 26, 2010 Reply Comments at 8.) PG&E subsequently opposed any disclosure. (March 8, 2011 Reply Comments on the PD at 4 - 5.)

from different informed perspectives. The current NDAs and confidentiality provisions allow full access and data disclosure to the Commission by some RPS participants but deny the same to others, thereby denying the Commission an opportunity for a complete presentation of information from a range of informed perspectives.

Moreover, allowing access to only one side denies the opportunity for a reasonable check and balance. TURN wisely recommends: "The Commission should operate with a 'trust but verify' approach to ensure that factual representations are accurate and complete."[45] We need to hear all informed perspectives on a topic, subject to a reasonable check and balance.

Therefore, we require IOUs to modify their NDAs or confidentiality provisions to permit bidders/sellers to disclose information on the bidding and PPA negotiating process to the Commission, including Commission staff. We will not, however, be drawn into negotiations and the taking of sides. We expect disclosures to focus on process (i.e., bidding and negotiating process), not individual bids. We instruct staff to strenuously avoid being drawn into negotiations or the taking of sides in the bargaining between an IOU buyer and an RPS bidder/seller.

TURN recommends that the modification include bidders/sellers presenting information to the PRG.[46] PG&E opposes this recommendation.

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[45] January 26, 2010 Reply Comments at 3.

[46] TURN's proposal is not a formal process for bidders/sellers to share information, but TURN says the process is expected to be informal and infrequent.

We are convinced by TURN for the following reasons to require modification of NDAs and confidentiality provisions to allow disclosure to PRGs.

TURN says that as a PRG member it is forced to rely on IOU representations without the opportunity to determine whether the information is correct and complete.[47] TURN reports that misleading or incomplete representations made by an IOU to the PRG could materially affect the positions taken by TURN and other PRG members.

We share this concern. PRG members must be able to 'trust but verify' and have access to a full range of informed perspectives subject to a reasonable check and balance (albeit informal and infrequent). This provides the best opportunity for their reaching informed opinions and recommendations. Because we rely on informed comments and recommendations by PRGs, we must ensure that they have reasonable access to information. This is equally true for the IE. Thus, we require that NDAs and confidentiality provisions permit disclosure of information on the bid and negotiation process to the Commission, Commission staff, PRG and IE.

## 5. Limited Issues Specific to a Plan

We comment here on limited issues specific to each Plan. As we have said before, conditional acceptance of these Plans does not constitute endorsement or adoption of proposed policy measures that have not yet

[47] TURN says this includes, for example, information on bids, bidder behavior, project details, contract discussions, summaries of issues under negotiation, and characterizations of requests made by bidders or other counterparties.

been fully vetted. It also does not constitute endorsement or adoption of each aspect of each Plan.[48] Rather, we conditionally accept each Plan, subject to limited required amendments and several suggestions. Each utility remains ultimately responsible for proposing and executing reasonable Plans that achieve RPS targets and goals. We will later judge the extent of each IOU's success, including the degree to which each IOU implements Commission orders, applies Commission guidance, demonstrates creativity and vigor in program execution and, most importantly, reaches program targets and goals.

### 5.1. PG&E

PG&E proposes several changes in contract terms, which we summarize in Appendix D. Unless otherwise identified and addressed in this decision, we accept these and other changes, subject to PG&E being responsible for reaching Program targets and goals.

### 5.2. SCE

We address four elements of SCE's Plan: modifications to project viability calculator, credit and collateral provisions, shortlist requirement, and other changes.

#### 5.2.1. Modifications to Project Viability Calculator

We directed PG&E, SCE, and SDG&E to use the Project Viability Calculator (PVC) as a tool for standardized comparison of the viability of

[48] See, for example, D.06-05-039 (at 61-62), D.07-02-011 (at 53) D.07-012-052 (at 299, Conclusion of Law 63), D.09-06-018 at 53-54.

projects bid into RPS solicitations.[49] The PVC, which was developed by Energy Division staff in collaboration with utilities, renewable project developers and ratepayer advocates, is a device that enables the utilities to evaluate the viability of a renewable energy project relative to all other projects that bid into the IOUs' RPS solicitations. The PVC uses standardized categories and criteria to quantify a project's strengths and weaknesses in key areas of project development. The PVC is one criterion in an IOU's bid evaluation, and is not intended to determine the exact merit of a particular project or contract.

SCE suggests modifications to the PVC based on experience with its use in the 2009 RPS Solicitation and recommendations of its IE.[50] These changes include modifying scoring criteria and guidelines to increase an IOU's flexibility in applying the PVC to each bid, and changing the role of the IE in evaluating the viability of each bid. SCE asserts that adoption of its proposed changes will lead to a more useful tool, and will help to more accurately evaluate the viability of renewable projects relative to one another.

DRA opposes SCE's recommendations to change the PVC. DRA argues that SCE does not provide sufficient information to justify why the Commission should support any of SCE's proposed changes to the PVC. DRA also disagrees with SCE's characterization of the role of the IE.

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[49] D.09-06-018 at 21 and Conclusion of Law 9.

[50] June 17, 2010 Second Amended 2010 RPS Procurement Plan at 39.

We decline to make changes to the PVC in this decision. Neither PG&E nor SDG&E comment on SCE's changes, nor do they raise concerns with the PVC. The PVC was developed by Energy Division staff as a tool for uniform, standardized comparison across projects and utilities. It is reasonable for changes to the PVC, if any, to be made by staff with stakeholder participation from utilities, renewable project developers and ratepayer advocates and applied uniformly. If SCE would like to make changes to the PVC used by all IOUs for RPS solicitations, it should work with staff to initiate the appropriate stakeholder process.

#### 5.2.2. Credit and Collateral Provisions

SCE says it is making three changes to its credit and collateral provisions.

First, SCE is increasing its development security requirements from $60 per kilowatt (kW) to $90 per kW for baseload facilities, and from $30 per kW to $60 per kW for intermittent facilities. In support, SCE says this provides reasonable security for SCE customers, and is consistent with industry position on allocating project failure risk between developers and utility customers.

Second, SCE is restructuring its performance assurance requirement to a tiered requirement: 3% of total revenues seller expects to earn in the early years, 5% to 6% for mid-contract years, and 3% to 5% for the remaining years. SCE says its tiered performance assurance amount averages 5% of total revenues over the full contract term, the same as the requirement in SCE's 2009 Plan. SCE asserts that the tiered structure reflects the risks related to different delivery terms while being responsive to changes in both (a) SCE's risk exposure over the contract term and (b) the renewable energy and financing markets. In further support, SCE contends the tiered structure benefits SCE customers (by better reflecting SCE's risk exposure over time and reducing the maximum exposure faced by customers). SCE says it also benefits sellers (by reducing the total capital requirement in early years when access to capital is constrained).

Third, SCE is eliminating the seller's debt to equity ratio requirement. In support, SCE says this credit provision often required a significant amount of negotiation without commensurate benefit. Further, SCE reports that enforcing compliance requires follow-up documentation and verification, thereby complicating contract administration and management. SCE asserts that SCE and its customers remain reasonably protected even without this specific requirement because (a) financial markets impose adequate discipline regarding debt to equity ratios and (b) SCE retains an existing contract provision that prohibits additional debt other than for development, construction and operation of the facility.

CalWEA and LSA oppose the deposit increase to $60/kW asserting it is double the amount required in the 2009 solicitation, and 600% of the amount required in the 2008 solicitation. CalWEA and LSA say SCE fails to show any change in circumstances over the past two years to justify a six-fold increase, and that ever-increasing deposit amounts create an artificial barrier to project development.

As we have said before regarding collateral, we have inadequate evidence to affirm any particular numbers. We are persuaded by SCE, however, that the annual cost of posting a Letter of Credit to cover SCE's proposed deposit level would generally be under 0.1% of the total capital cost of a new renewable energy facility.[51] Deposits reasonably balance risk between stakeholders. SCE's proposed level does not appear to be an unreasonable barrier to project development.

We provide utilities flexibility to make many business decisions subject to holding them accountable for results. In that context, we accept SCE's proposals consistent with SCE being responsible for SCE's portion of California RPS Program success, and subject to SCE meeting its program targets and goals.[52]

#### 5.2.3. Shortlist Requirement (Interconnection Studies)

SCE proposes in its comments on the PD that it be permitted to amend its 2011 Plan to include a new shortlisting requirement. In particular, SCE says the Commission should allow SCE to add certain interconnection study requirements in order for a project to be eligible to be shortlisted. The requirements are that a project is active in an interconnection queue and has at least completed (a) a Phase 1

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[51] Reply Comments dated January 26, 2010 at 15.

[52] Fixed prices for 20 year contracts place a significant risk of bad outcomes on ratepayers. (See, for example, D.10-12-048, Appendix C.) We lack data from SCE or parties to access whether the risk of default by a project late in a 20 year contract is adequately compensated by a reduced performance assurance requirement in the later years (e.g., given the potential for the project to default on the contract but make sales to another buyer at a higher price). As discussed above (e.g., Section 3.2 and opening paragraph of Chapter 5), we provide utilities flexibility to make many business decisions but hold utilities accountable for the results.

interconnection study, (b) a System Impact Study, or (c) 9 of 10 screens in the fast-track interconnection process. In support, SCE says this incorporates lessons learned since the filing of the draft Plans, will provide more certainty around potential network upgrade and interconnection costs, and will permit a more accurate evaluation of such costs in the LCBF evaluation. SCE's proposal is opposed by IEP and CalWEA/LSA. We decline to authorize the change requested by SCE.

SCE makes the request late in the process. Because late changes have been an issue in prior Plans,[53] the assigned Commissioner' Scoping Memo scheduled a specific date for final Plan updates. In addition, respondents filed subsequent motions for consideration of Plan changes. SCE should have made its proposal by the date for final Plan updates, or by subsequent motion.

Nonetheless, even if considered now, SCE fails to make a convincing case. The PVC specifically scores both interconnection and transmission. The LCBF methodology permits quantitative and qualitative assessment of both interconnection and transmission. SCE fails to convincingly show that the PVC and LCBF tools result in shortlisting projects that would be rejected under its new requirements. We also note that neither PG&E nor SDG&E join SCE in making this request. We believe all three IOUs can successfully use their PVC and LCBF tools to rank and shortlist projects without the specific additional requirements proposed by SCE.

[53] See, for example, July 27, 2009 ALJ Ruling regarding late changes proposed to 2009 RPS Procurement Plans.

Improvements in the solicitation and selection process are always welcome, however. We encourage SCE to renew its proposal at an appropriate future time (accompanied by convincing evidence and argument) if SCE continues to believe that these or other requirements will improve the RPS Program.

#### 5.2.4. Other

SCE makes several other changes, which we summarize in Appendix D. No party presents compelling comments in opposition to these changes, particularly when considered in light of our approach of "flexibility with accountability." We accept these changes, consistent with SCE being responsible for it portion of program success, and subject to SCE meeting program targets and goals.

### 5.3. SDG&E

We address two elements of SDG&E's Plan: Time of delivery (TOD) factors and other.

#### 5.3.1. TOD Factors

RPS Plans include time-differentiation of prices to be paid for electricity generated by renewable resources. The time-differentiation is based on TOD factors. In 2009, we directed SDG&E to present with its next Plan both energy only and all-in factors, and make a showing on the reasonableness of its TOD factors. (D.09-06-018 at 48.) We did this because of the wide variation in TOD factors between IOUs,[54] and the

[54] For example, for the 2009 RPS solicitation the summer on-peak TOU factor for SCE was 3.13 and for SDG&E was 1.64. (D.09-06-018 at 47, footnote 38.)

contention by some parties that SDG&E's TOD factors were energy-only and not all-in (capacity and energy).

SDG&E says in its current showing that:

> In all previous RPS RFOs, TOD factors used by SDG&E were based upon energy-only calculations, with no capacity costs included. Because of this, a Resource Adequacy Adder was used to simulate the additional cost of capacity [when making resource choices within the LCBF methodology] … In future RFOs, SDG&E intends to use the all-in TOD factors … with capacity costs included in their calculation … The Resource Adequacy Adder will be discontinued to avoid double-counting capacity costs. (SDG&E April 9, 2010 Further Amended Draft 2010 RPS Procurement Plan at 28.)

SDG&E proposes the following all-in TOD factors:

**2011 RPS SOLICITATION TOD FACTORS**

| PERIOD | SUMMER | WINTER |
|---|---|---|
| On-peak | 2.501 | 1.089 |
| Semi-peak | 1.342 | 0.947 |
| Off-peak | 0.801 | 0.679 |

No party opposes SDG&E's proposal. TOD factors of SCE and PG&E are all-in. Accepting SDG&E's proposal will make the approach to TOD factors by the three IOUs uniform, and will reasonably "recognize the extent of the need for additional capacity." (D.09-06-018 at 48 citing D.06-05-039 at 68.) We accept SDG&E's TOD proposal.

#### 5.3.2. Other

SDG&E proposes several other changes, which we summarize in Appendix D. No party presents compelling comments in opposition to these changes, particularly when considered in light of our approach of "flexibility with accountability." We accept these changes consistent with

SDG&E being responsible for it portion of program success, and subject to SDG&E meeting program targets and goals.

### 5.4. PacifiCorp

Last year we accepted PacifiCorp's 2009 IRP Supplement, but noted the need for certain improvements in 2010. (D.09-06-018 at 66-69.) In particular, we said that PacifiCorp must do a better job of explaining how it will achieve 20% by 2010, and described several examples.

PacifiCorp filed its 2008 IRP on May 29, 2009, and its Supplement on June 29, 2009. (D.08-05-029.) In response to the Amended Scoping Memo, PacifiCorp referred to the 2008 IRP and the Supplement, and filed an Additional Supplement on December 18, 2009.

Among other things, PacifiCorp explains that the RPS need identified in its 2008 IRP is being met by multiple RFPs. The 2008 IRP (Action Plan, Action Item 1), according to PacifiCorp, identifies up to 2,000 MW of RPS resources to be acquired by 2013, including 1,400 MW by 2010, and an additional 600 MW by 2013. PacifiCorp held two RFPs: one on October 6, 2008, and another on July 8, 2009. PacifiCorp also explains that it pursues PPAs with qualifying facilities where the company also receives the associated renewable energy credits (RECs) to meet its RPS requirement. PacifiCorp's August 2009 Semi-Annual Compliance Report (attached to the December 18, 2009 Additional Supplement) shows PacifiCorp's compliance going from an actual APT (adjusted by flexible compliance) of 8.3% in 2008, and forecast of 12.2% in 2009, to 20.0% in

2010.[55] Just as last year, however, it remains unclear if the past RFPs have produced sufficient response for PacifiCorp to reach 20%, or if further RFPs are needed and, if so, how much and when (e.g., solicitation of another "x" MW in 2011 or 2012).

We accept PacifiCorp's Additional Supplement but, just as with the IOUs, we do so consistent with PacifiCorp being responsible for its portion of RPS Program success, and subject to PacifiCorp meeting California Program targets and goals. We again direct PacifiCorp to do a better job in its next showing of explaining how it will achieve California RPS targets.

### 5.5. Sierra (CalPeco)

Sierra reported last year that it was in compliance with its California RPS procurement obligations, expected to remain in compliance, and would be sufficiently resourced to meet its 20% obligation by 2010. Because of this, Sierra stated that it had no RPS solicitation pending or scheduled for California, but would issue an RFP to comply with its Nevada-based requirements. (D.09-06-018 at 69.) Sierra now reports that there are no significant changes to its accepted 2009 Supplement.[56]

Sierra's 2009 IRP Supplement reasonably addresses its unique, fully-RPS resourced position. We are confident that Sierra, now CalPeco, will provide more detail in subsequent reports, as necessary, should this fully-RPS resourced situation change. We accept the Supplemental Filing

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55 PacifiCorp's August 2010 Semi-Annual Compliance Report shows adjusted actual APT of 9.1% in 2008, and 10.6% in 2009.

56 December 18, 2009 Supplemental Filing at 1.

consistent with CalPeco being responsible for its portion of RPS Program success, and subject to CalPeco meeting California Program targets and goals.

## 6. Schedule for 2011 Solicitations and Organization of 2012 Plans

### 6.1. Schedule for 2011 Solicitation

The IOUs propose similar schedules for the next solicitation. The proposals include a date before which an IOU may not request an exclusivity agreement from a bidder before continuing negotiations.

We adopt a schedule that reflects Commission experience with the 2009 solicitation. (See Appendix B.) We limit the adopted schedule to major milestones. This permits IOUs and staff reasonable flexibility, just as we did in 2008 and 2009.

We also adjust the date for submitting contracts that may be earmarked for meeting 2010 targets. Given the timing of this solicitation, we authorize a reasonable amount of time for contracts that result from this solicitation to apply via earmarking to 2010 targets. This does not in any way limit when contracts from this solicitation may be submitted for RPS purposes generally. It does so only for the limited purpose of certain earmarking, just as we have done in the past.[57]

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[57] For example, IOUs were required to submit advice letters with contracts from the 2009 solicitation by April 30, 2010 to count for earmarking from that solicitation. (D.09-06-018, Appendix B, line 8.) This does not foreclose an IOU submitting a contract at any time (now or in the future) from the 2009 solicitation for Commission consideration as it may apply to RPS targets generally.

As we have done before, we authorize the Energy Division Director, with notice to IOUs and parties, to change the schedule as appropriate or necessary for efficient administration of the 2011 solicitation. Parties may seek schedule modification by request to the Executive Director (Rule 16.6 of the Commission's Rules of Practice and Procedure).[58]

### 6.2. Organization of 2012 Plans and IRPs

Given the timing of this solicitation, the next filing of draft Plans with subsequent actual solicitation will most likely be in the context of 2012. We adopt for the 2012 Plans the same basic approach as we used in developing and reviewing the 2006, 2007, 2008, 2009, and 2011 Plans.[59] That is, we expect the filing and service of 2012 draft RPS plans and draft RFOs later this year by the three IOUs. This is also true of the next review for the MJUs. It will for the first time also apply to ESP procurement plans.[60] The specific schedule and details will be set by the assigned Commissioner or ALJ.

Moreover, as we have also done before,[61] we authorize the assigned Commissioner to assess the adequacy of TRCRs used in the LCBF ranking of bids. The assigned Commissioner or ALJ should set dates, as needed, for utilities to request information for the TRCRs, to file draft TRCRs, and

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[58] See, for example, D.09-06-018, Ordering Paragraph 3.

[59] See D.05-07-039 at 29, D.06-05-039 at 58, D.07-02-011 at 61, D.08-02-008 at 46, and D.09-06-018 at 70.

[60] D.11-01-026, Ordering Paragraph 1.

[61] D.09-06-018, Ordering Paragraph 6.

for parties to file comments and replies on the draft TRCRs. The assigned Commissioner should then assess the adequacy of the draft TRCRs, and determine whether the reports should be modified or other steps taken before the results are used in the ranking of bids.

We encourage the IOUs to consider developing and proposing uniform, streamlined Plans that may either be adopted for more than one year, or for more than one year with only minor updates. We remain on a schedule which largely anticipates annual RPS solicitations for the largest three IOUs.[62] We again encourage IOUs to consider proposing something other than an annual cycle. (See D.06-05-039 at 55-60; D.08-02-008 at 46; D.09-06-018 at 71.) As we have observed several times, we think there are other reasonable options to the annual approach we now use. We encourage IOUs to consider the options and, where feasible, propose alternatives that accomplish RPS Program objectives while mitigating some of the burdens placed on all stakeholders by the current procedures.[63] In particular, we encourage IOUs to consider an approach

[62] An annual solicitation paralleled the historic requirement that each retail seller increase its procurement annually by at least 1% until it reached 20% by 2010. The annual 1% minimum growth requirement is modified by SB 1X 2. Respondents and parties may wish to consider proposing a procurement schedule that is reasonably parallel to the procurement targets in SB 1X 2, or another reasonable schedule. For now, we anticipate annual solicitations, but remain open to other than an annual cycle when that promotes efficiencies.

[63] Further standardization, uniformity, and streamlining may make it possible for the Commission to authorize several solicitations at one time, or make other efficiency improvements. For example, one Commission decision might authorize an RPS solicitation by the three IOUs to be held once every 90 days for

*Footnote continued on next page*

which would permit quite frequent, if not continuous, RPS solicitation in a competitive market.

### 7. Additional Resources

We are implementing an RPS Program that requires electrical corporations to undertake reasonable actions in pursuit of reaching and maintaining a renewables resource base with a target equal to 20% of retail sales by 2010, and a further goal of 33% by 2020. Upon SB 1X 2 becoming effective, the statutory requirement becomes 33% by 2020. These percentages involve a very large quantity of resources.

Our implementation of this program must be responsive to the needs and interests of all stakeholders. This includes the needs of electrical corporations and developers as they pursue these targets and goals, while balancing complimentary and competing interests of many other stakeholders, including ratepayers, other government agencies, and the public. Our implementation and administration can be complicated, and often involves many significant technical details. It is important that we accomplish our mission efficiently, effectively, and timely so that electrical corporations have a reasonable opportunity to reach statutory requirements regarding both renewable resources and environmental goals. At the same time we must satisfy our basic responsibilities to see that the electricity system is safe and reliable at just and reasonable rates

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two years, or until a trigger has been reached. The trigger might be when RPS deliveries to an IOU reach a certain threshold.

charged to ratepayers at the lowest reasonable overall total cost while meeting other necessary goals (e.g., reasonable resource diversity).

We can best achieve these goals if we authorize the Executive Director to hire and manage a contractor, or contractors, to provide technical and other support to assist staff address some or all the following areas, with reimbursement from the utilities.[64] The tasks are:

1. refining and calculating the market price referent (MPR) for existing fixed-price feed-in tariffs (§ 399.20);
2. updating renewable resource assessments and identifications of areas for renewable energy development;
3. evaluating impacts of achieving a 33% renewables portfolio to implement resource planning standards (e.g., updating the 33% RPS ranking methodology and updating factors in the 33% RPS calculator related to the viability, risk, timing and integration of RPS generation and transmission projects); and
4. others as necessary to promote RPS Program goals (e.g., analyzing the cost of renewables integration; developing long-term RPS resource plan; analyzing distributed generation market potential and integration; analyzing optimal approaches to cost containment and risk management; assessing emerging renewables markets).

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[64] The annual Budget Act gives the Commission certain specific and limited ongoing reimbursable expenditure authority. Prior to exercising this authority, the Commission must issue a decision that identifies the contracting activities to be undertaken by the Commission, and the costs subject to reimbursement by utility companies. This decision serves that purpose, and allows the Commission to utilize the reimbursable authority granted in the annual Budget Act. (Budget Act of 2010, Stats. 2010, Ch 712, Item 8660-001-0462(6).)

Beginning with the 2010-11 fiscal year, we will authorize the expenditure of up to, but no more than, $600,000 annually for up to four years.[65] The Executive Director will approve the expenditures and seek reimbursement from PG&E, SCE, and SDG&E. Reimbursement will be sought from these three utilities on a proportional basis in relationship to the annual retail sales used for the RPS Program, as reported each year in the March 1 compliance report (or other first report each year as determined by the Executive Director). PG&E, SCE, and SDG&E are authorized to record these RPS third-party technical support costs associated with RPS technical contractor activities in their Renewables Portfolio Standard Costs Memorandum Accounts (RPSCMA). These costs may be recorded when paid, for later recovery via rates. Other LSEs are excused.[66]

## 8. Comments on Proposed Decision

On February 11, 2011, the proposed decision of ALJ Mattson in this matter was mailed to the parties in accordance with Section 311 of the

[65] To the extent the maximum annual amount is not expended in each year of the contract period, such amounts may be carried forward and expended in a subsequent year. The maximum nominal value of this contract shall not exceed $2.4 million. If not spent within four years, the funds may be spent in subsequent years (beyond year four) as long as the total does not exceed $2.4 million. (See D.11-01-016.)

[66] We excuse other LSEs since we do not regulate the rates of ESPs and CCAs, while multi-jurisdictional, small and other IOUs have fewer sales compared to those of the three IOUs, making the complication of additional invoicing for a small amount of money more than the benefit of spreading the cost to all IOUs. (See D.06-10-050 at 54 regarding similar treatment.)

Public Utilities Code and Rule 14.3 of the Commission's Rules of Practice and Procedure (Rules). On March 3, 2011, 2011, comments were filed by PG&E, SCE, SDG&E, IEP, CalWEA/LSA, and CAlifornians for Renewable Energy, Inc. On March 8, 2011, reply comments were filed by PG&E, SCE, IEP, and CalWEA/LSA. As required by our rules, comments must focus on factual, legal or technical errors and, in citing such errors, must make specific references to the record. Comments which merely reargue positions taken in the proceeding are given no weight. (Rule 14.3.)

Based on comments and reply comments we make several modifications. These include changes to the treatment of economic curtailment, congestion costs, NDAs and confidentiality provisions, 2011 solicitation schedule, and the schedule for 2012 plans. We clarify that reimbursable consultant costs may be entered into RPSCMAs, and are not subject to separate later application for recovery in rates (i.e., are treated in the normal course of processing RPSCMAs for rate recovery). We decline to adopt SCE's recommendation to permit SCE to include new shortlisting requirements (relative to interconnection studies).

## 9. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner, and Anne E. Simon and Burton W. Mattson are the assigned ALJs for this proceeding.

## Findings of Fact

1. No motion for evidentiary hearing was filed.
2. MRTU uses LMP price signals to reflect supply and demand in multiple locations.

3. MRTU significantly changes the way generation resources are scheduled, dispatched and potentially located, and it is reasonable for IOU contracts to reflect the MRTU's economic approach to resource allocation.

4. The economic curtailment proposal in the pro forma contracts of PG&E and SCE (as modified) are financeable, share congestion cost risk between stakeholders, provide economic information to parties, and are negotiable.

5. Making specific congestion cost information (to the extent used in LCBF evaluations) available to bidders promotes transparency in the LCBF methodology.

6. PG&E's economic curtailment proposal effectively results in the potential for economic curtailments in excess of five percent.

7. Energy-only interconnections may increase congestion cost risk.

8. Congestion cost concerns are addressed by economic curtailment contract terms and disclosure of LCBF treatment of congestion cost (including price data if specific data is used), and need not also be addressed by eliminating an interconnection option currently allowed by the CAISO.

9. We have previously rejected proposals for non-zero integration cost adders, and no new information or argument presented here justifies a change.

10. The stay of D.10-03-021 has been lifted, and the Commission now permits the use of TRECs for RPS compliance.

11. There was robust response from resources located in the Imperial Valley to the 2009 RPS solicitation.

12. IOU proposals regarding CAISO's SCP reasonably allocate not just benefits but also burdens; and reasonably allocate potential penalties to the seller, who is best positioned to mitigate those penalties.

13. Evidence presented here does not demonstrate that the Commission process for fast-track review of short term contracts does not work, cannot work, or cannot be reasonably modified, if necessary.

14. IOU-proposed pilot programs for short-term contract preapprovals lack reasonable limits and specificity on price and cost.

15. IOU Plans continue to be complex documents (including many attachments, different model contracts and multiple related forms), but the goals of increased simplicity, transparency, efficiency and competition can be advanced by the three IOUs continuing to make incremental improvements in standardization and uniformity of Plan form and format.

16. Several events have occurred that have not been adequately or fully reflected in draft Plans.

17. IOU Plans (including protocols, pro forma contracts and other attachments) are the vehicle for each IOU in one complete, comprehensive and up-to-date document to explain to all stakeholders how the IOU plans to achieve state-mandated RPS targets and goals, including but not limited to an assessment of supply and demand, use of flexible compliance, and a bid solicitation.

18. MJUs must now file, in years in which an IRP is not filed, a comprehensive IRP Supplement at the same time as IOUs file their Plans, but this creates a logistical challenge for MJUs and is less efficient than setting a fixed filing date.

19. SCE's proposal to amend its 2011 Plan to include a new shortlisting requirement is made late in this proceeding, and SCE fails to convincingly show that the PVC and LCBF tools result in shortlisting projects that would be rejected under its new requirement.

20. IOUs propose several changes in contract terms including, but not limited to, SCE's proposed changes to credit and collateral provisions, SCE's new shortlisting requirement, and SDG&E's proposed changes to TOD factors.

21. The PVC is a standardized comparison tool for project screening, and is one factor in the evaluation of projects, but is not determinative of the exact merit of a particular project or contract.

22. PacifiCorp's Supplement does not clearly show if prior RFPs have produced sufficient response for PacifiCorp to meet California RPS targets or if further action is needed and, if so, how much and when.

23. The RPS Program involves implementing statutes requiring that electrical corporations take reasonable actions to reach and maintain a very large quantity of renewable resources, with Commission implementation and administration often involving many complicated and significant technical details while balancing complimentary and competing interests of a wide range of stakeholders.

## Conclusions of Law

1. With some exceptions, electric utilities are required to prepare a renewable energy procurement plan, and the Commission is required to review and accept, modify, or reject each plan.

2. Electric utilities should continue to have reasonable flexibility in the way each satisfies RPS program requirements, subject to Commission

guidance, limited specific requirements, and certain specific dates (where applicable) for the 2011 solicitation.

3. Conditional approval of each 2011 draft Plan (including Protocol, RFO, RFP, model contracts, other forms), and each Supplement to the IRP, does not constitute endorsement or adoption of each element of each Plan or Supplement; rather, each utility remains responsible for overall program success, subject to rules for flexible compliance and tests of reasonableness (e.g., how each entity administers the program, including the extent to which each entity takes Commission guidance; demonstrates creativity and vigor in program execution; and successfully reaches program targets, goals and requirements).

4. The proposed 2011 RPS Procurement Plans of PG&E, SCE, and SDG&E should each be conditionally accepted, subject to the guidance, necessary modifications, changes and clarifications stated in this order, including, but not necessarily limited to, each item summarized in Appendix A; and the Supplements to IRPs of PacifiCorp and Sierra (now CalPeco) should each be accepted subject to the guidance stated in this order including, but not limited to, the relevant items summarized in Appendix A.

5. PG&E, SCE, and SDG&E should each, within 14 days of the date this order is mailed, file a Final 2011 Plan with the Commission's Docket Office, serve it on the service list, and also file a copy with the Energy Division Director. Unless suspended by the Executive Director or Energy Division Director within 21 days of the date this order is mailed, each utility should use its Final 2011 Plan for its 2011 RPS solicitation.

6. Parties to executed contracts should use the dispute resolution provisions in existing contracts to address differences regarding economic curtailment, and the Commission should not disturb the negotiation process for contracts now being negotiated.

7. IOUs should be held accountable for contract failure due to unreasonable contract administration of economic curtailment terms.

8. Each IOU should include buyer-directed economic curtailment terms in its Final 2011 Plan.

9. SCE should incorporate assessment of congestion costs in its 2011 LCBF evaluations; both SDG&E and PG&E should continue to assess congestion costs in their 2011 LCBF evaluations (as they now do or commit to doing); all three IOUs should modify their LCBF descriptions to include economic curtailment and congestion cost information, as necessary; all three IOUs should release congestion cost information to bidders (to the extent specific data is used in LCBF evaluations) in order to promote transparency of the LCBF methodology; and all three IOUs should modify their LCBF descriptions, as necessary, to make treatment of RA, and use of RA adders, clear.

10. IOU Final 2011 Plans should not include non-zero integration cost adders, but IOUs should be allowed to file an advice letter to amend Final 2011 Plans if such adders are developed in R.10-05-006.

11. Final 2011 Plans filed pursuant to this order by an IOU (and Amended Supplements, if any, filed by an MJU) should include planned use of TRECs in a manner consistent with that authorized by the Commission.

12. No remedial measures should be adopted within RPS Plans regarding the Sunrise project and Imperial Valley resources but specific monitoring of Imperial Valley proposals and projects should continue; and IOUs should be encouraged to do outreach and take all reasonable action to secure optimal resource development, including possible special Imperial Valley bidder's conferences.

13. IOUs' proposals regarding treatment of benefits and burdens of CAISO's SCP should be accepted.

14. IOUs' proposals for pilot programs regarding preapproval of short-term contracts should be rejected.

15. IOUs should not wait until formal commencement of the development of the next Plan but should begin now to meet and coordinate to make incremental improvements toward adopting a common, uniform and streamlined form and format among the IOUs, including the overall summary document and multiple attachments (e.g., Protocol, RFP, RFO, model contracts, multiple related forms).

16. Final 2011 Plans filed pursuant to this order should amend draft Plans to include recent events not fully reflected in draft Plans to the extent they are intended to be used by IOUs to meet Program targets and goals (e.g., RAM, solar PV programs, small power production reflected in the adopted QF Settlement Agreement, RPS utility-owned generation).

17. MJUs should file a comprehensive IRP Supplement on July 15 of each year in which an IRP is not filed.

18. NDAs and confidentiality provisions should be modified to permit bidders/sellers to disclose information on the bidding and PPA negotiating process to the Commission, Commission staff, PRG and IE; but

neither the Commission nor Commission staff should become involved in the negotiations, or the taking of sides in the bargaining, between buyer and bidder/seller.

19. Changes in the PVC should be made by Energy Division staff with stakeholder participation.

20. SCE's proposal to amend its 2011 Plan to include a new shortlisting requirement should be rejected.

21. IOUs' proposed changes (e.g., contract terms, SCE credit and collateral provisions, SDG&E TOD factors), unless specifically rejected herein, should be accepted to the extent described in this order consistent with the IOU ultimately being responsible for its portion of RPS Program success.

22. PacifiCorp should make clear in its next IRP or Supplement how it intends to achieve 20% by 2010.

23. Sierra's Supplement should be accepted, subject to Sierra (now CalPeco) being responsible for meeting California RPS Program targets and goals.

24. The 2011 RPS solicitation schedule in Appendix B should be adopted.

25. The same approach for Commission review and acceptance, rejection or modification of the 2012 RPS Procurement Plans should be used as employed for prior Plans, with the assigned Commissioner setting the specific schedule and addressing TRCRs.

26. The Executive Director should hire and manage one or more consultants to provide technical support and assist staff with certain tasks,

with cost recovery on a proportional basis from the three largest IOUs, as provided herein.

27. SCE, PG&E, and SDG&E should each be authorized to record RPS technical contractor costs in their RPSCMAs; the costs should be recorded when paid; the costs should be subject to a limit on the total prorated amount to the three IOUs of $600,000 annually for up to four years; unspent funds in one year should be eligible to be carried forward to the next year (including years beyond year four), but the total expenditure should not exceed $2.4 million.

28. Evidentiary hearings are not necessary for the issues raised in this decision.

29. This proceeding should remain open.

30. This order should be effective today so that the 2011 RPS solicitation may proceed without delay.

## O R D E R

**IT IS ORDERED** that:

1. Each utility-proposed renewable energy procurement plan, as part of the California Renewables Portfolio Standard Program, is conditionally accepted for the next Renewables Portfolio Standard Program solicitation. Each Plan includes, but is not limited to, Protocols, Request for Proposals, Request for Offers, model contracts and/or Power Purchase Agreements. The Plans are in the following documents:

    a. The Pacific Gas and Electric Company "2010 Renewable Energy Procurement Plan (Draft Version)" filed December 18, 2009 (as updated on February 17, 2010, and amended on April 9 and June 6, 2010).

b. The Southern California Edison Company "2010 RPS Procurement Plan" filed December 18, 2009 (as amended on April 9 and June 12, 2010).

c. The San Diego Gas & Electric Company "2010 Draft Renewable Procurement Plan" filed December 18, 2009 (as updated on February 17, 2010 and amended on April 9, 2010).

2. Each document referenced above is adopted on the condition that:

a. Within 14 days of the date this order is mailed, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file and serve a Final 2011 Renewables Portfolio Standard Procurement Plan that is consistent with all the orders in this decision, plus all guidance in this decision with which the utility agrees, and simultaneously file a copy with the Director of the Energy Division. The orders and guidance are summarized in, but not limited to, Appendix A.

b. Unless suspended by the Executive Director or Energy Division Director within 21 days of the date this order is mailed, each utility shall use its Final 2011 Renewables Portfolio Standard Procurement Plan for its 2011 solicitation.

3. The 2011 Renewables Portfolio Standard procurement schedule shall be as stated in Appendix B. The schedule may be modified by the Executive Director or Energy Division Director as reasonable and necessary for efficient administration of this solicitation. Parties may seek schedule modification by letter to the Executive Director (pursuant to Rule 16.6 of the Commission's Rules of Practice and Procedure).

4. The PacifiCorp "Additional Supplement to its 2008 Integrated Resource Plan (2010 Supplement)" filed December 18, 2009, and the Sierra Pacific Power Company (now California Pacific Electric Company, LLC)

"Renewables Portfolio Standard 2010 Supplemental Filing" filed December 18, 2009, are each accepted. In its next Plan, PacifiCorp shall improve its explanation of how it will achieve California Renewables Portfolio Standard Program targets.

5. Consistent with all prior and current Commission orders and directions, each utility ultimately remains responsible for reasonable Renewables Portfolio Standard Program outcomes, within application of flexible compliance criteria. The Commission shall later review the results of renewable resource solicitations submitted for Commission approval, and accept or reject proposed contracts based on consistency with each approved Renewables Portfolio Standard Procurement Plan. The Commission shall also judge contract results, program results, and non-compliance pleadings by (but not limited to) considering the degree to which each utility implements Commission orders; reasonably elects to take or reject the guidance provided herein; reasonably demonstrates creativity, innovation and vigor in program execution; reaches program targets, goals, and requirements; and shows it took all reasonable actions to achieve compliance, including but not limited to the factors identified in this and prior orders.

6. The assigned Commissioner or Administrative Law Judge in this, or a successor, proceeding shall set a schedule for the filing and service of proposed Renewables Portfolio Standard Procurement Plans for the 2012 solicitation, as necessary. The assigned Commissioner or Administrative Law Judge shall set a schedule for matters related to Transmission Ranking Cost Reports to be used in the ranking of bids in a Renewables Portfolio Standard solicitation. The assigned Commissioner shall assess

the adequacy of each Transmission Ranking Cost Report based on filed comments and reply comments, and shall determine whether each Transmission Ranking Cost Report shall be accepted, modified, or other steps taken before a Transmission Ranking Cost Report is used in ranking bids in a Renewables Portfolio Standard solicitation.

7. PacifiCorp and California Pacific Electric Company, LLC shall file by July 15, in years in which an Integrated Resource Plan is not filed, a Comprehensive Renewables Portfolio Standard Supplement to the Integrated Resource Plan.

8. The Executive Director may hire and manage one or more contractors to perform tasks described in this order for the purpose of advancing Renewables Portfolio Standard Program goals. Such costs, if any, shall not exceed a total annual amount of $600,000 for up to four years (with a cumulative total not to exceed $2.4 million). The costs shall be reimbursed by Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company on a proportional basis in relationship to retail sales reported each year in the March 1 Renewables Portfolio Standard compliance report (or other first report each year as directed by the Executive Director). Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are authorized to record payments for these Renewables Portfolio Standard technical contractor costs into their Renewables Portfolio Standard Costs Memorandum Accounts. These costs shall be recorded when paid. Unspent funds in one year may be carried over and spent in a subsequent year, including years beyond year four, but the total shall not exceed $2.4 million.

9. Rulemaking 08-08-009 remains open.

This order is effective today.

Dated April 14, 2011, at San Francisco, California

MICHAEL R. PEEVEY
President
TIMOTHY ALAN SIMON
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
MARK FERRON
Commissioners

I reserve the right to file a concurrence.

/s/ TIMOTHY ALAN SIMON
Commissioner

## APPENDIX A

## SUMMARY OF KEY ITEMS

The attached decision reviews and conditionally accepts the 2011 RPS Procurement Plans of PG&E, SCE, and SDG&E. It reviews the Supplement to the IRP of CalPeco (formerly Sierra) and PacifiCorp. The orders and guidance, while not limited to those stated in this abstract, are summarized below in the same sequence addressed in the attached decision.

1. **Buyer-Directed Economic Curtailment:**

    a. **Pre-2011 Contracts**: Decline to interpret terms in executed contracts; disputes of terms in executed contracts should be addressed via dispute resolution procedures within the contract; negotiations may occur on this and other modifiable terms in contracts not yet executed; an IOU is responsible for reasonable contract administration, including interpretation of terms in executed contracts and prior pro forma contracts.

    b. **2011 Contracts**: Require each IOU to include provisions in its Final 2011 Plan (including pro forma contract) for buyer-directed economic curtailment; require SCE to include congestion cost assessment in 2011 LCBF evaluations; affirm the continued assessment by SDG&E and PG&E of congestion costs in their LCBF evaluations; require each IOU to modify its LCBF description, as necessary, to explain use of economic curtailment and congestion costs; release specific congestion cost data (to the extent used in LCBF evaluations) to bidders as part of making its LCBF methodology transparent.

    c. **Full Deliverability**: Decline to require that projects use the fully deliverable interconnection option. Require each IOU to modify its LCBF description, as necessary, to make its treatment of resource adequacy, and use of resource adequacy adders, clear as part of making its LCBF methodology transparent.

2. **Integration Cost Adders**: Decline to adopt non-zero integration cost adders; require each IOU to exclude language that would incorporate use of non-zero integration cost adders; permit each IOU to file an advice letter to amend its Final 2011 Plan if an adder is developed in R.10-05-006.

3. **Tradable Renewable Energy Credits**: Final 2011 Plans should include an IOU's intended use of TRECs; an MJU should file an Amended Supplement if its planned TREC use is changed as a result of the Commission's recent order.

4. **Sunrise/Imperial Valley Issues**: Decline to order any remedial measures, but continue monitoring of Imperial Valley proposals and projects; encourage each IOU to do appropriate outreach, including possible special Imperial Valley bidder's conferences.

5. **CAISO Standard Capacity Product**: Adopt IOU proposals to allocate both benefits and risks of CAISO SCP.

6. **Pilot Program for Preapproval of Short-Term Contracts**: Decline to adopt IOU proposals for preapproval of short-term contracts; encourage IOUs to be creative and vigorous in their use of Commission-authorized fast-track approval process; encourage IOUs to continue to consider and propose refinements to fast-track approval process based on experience with that process and the market.

7. **Plan Organization and Standardization**: Encourage IOUs to coordinate and develop a uniform, streamlined Plan among IOUs; encourage IOUs to increase Plan standardization in form and format, including solicitation protocols and pro forma contracts, to the fullest extent possible beginning immediately, with one proposed standardized contract among the IOUs for Commission preapproval (with negotiation between parties of that standardized contract before execution always permitted, to the extent necessary).

8. **Other Updates**: Each Final 2011 Plan should be a complete, comprehensive, up-to-date plan of all procurement tools an IOU intends to use to reach RPS targets and goals, including procurement via the Renewable Auction Mechanism, solar photovoltaic programs, qualifying facilities, utility-owned RPS generation, and any others to be used by an IOU.

9. **Date for MJU Supplemental Filing**: Set July 15 as the date by which MJUs must file comprehensive supplements in years when an Integrated Resource Plan is not filed.

10. **Nondisclosure Agreements**: Non-disclosure agreements and confidentiality provisions must be modified to permit disclosure by bidders/sellers of the bidding and negotiating process to the Commission, Commission staff, PRG, and IE. The disclosures must focus on process and not individual bids. The Commission and Commission staff will not be drawn into negotiations or the taking of sides in the bargaining between buyer and bidder/seller.

11. **PG&E**: Accept changes proposed by PG&E subject to PG&E being held responsible for reaching program targets and goals.

12. **SCE**:

    a. **Modifications to Project Viability Calculator**: Decline to authorize changes proposed by SCE; PVC is a uniform, standardized tool developed by Energy Division staff used for project assessment and comparisons, but IOUs may work with Energy Division staff to initiate a stakeholder process if modifications are sought.

    b. **Credit and Collateral Provisions**: Accept changes proposed by SCE subject to SCE being held responsible for reaching program targets and goals.

    c. **Shortlisting Requirement**: Decline to authorize new shortlisting requirement proposed by SCE.

d. **Other**: Accept other changes proposed by SCE subject to SCE being held responsible for reaching program targets and goals.

13. **SDG&E**:

    a. **TOD Factors**: Accept proposed changes to TOD factors based on all-in (capacity plus energy) factors.

    b. **Other**: Accept other changes proposed by SDG&E subject to SDG&E being held responsible for reaching program targets and goals.

14. **PacifiCorp**: Additional Supplement is accepted, subject to PacifiCorp being held responsible for reaching program targets and goals; direct PacifiCorp to do a better job in its next showing of explaining how it will achieve California RPS targets.

15. **CalPeco**: Accept IRP Supplement subject to CalPeco being held responsible for reaching program targets and goals.

16. **Schedule:**

    a. **2011**: Schedule in Appendix B is adopted.

    b. **2012**: The assigned Commissioner or Administrative Law Judge will set the specific schedule; the assigned Commissioner shall rule on the proposed Transmission Ranking Cost Reports; parties should continue to consider and, where feasible, propose alternatives that accomplish RPS Program objectives while mitigating some of the burden placed on all stakeholders from an annual solicitation; encourage IOUs to propose Plans that may either be adopted for more than one year, or more than one year with only minor updates; encourage IOUs to propose something other than an annual solicitation cycle and, in particular, consider approaches that would permit frequent, if not continuous, RPS solicitations.

17. **Additional Resources**: The Executive Director may hire and manage one or more consultants to accomplish RPS Program goals at a cost not to exceed $600,000 per year for no more than four years, with the costs reimbursed by PG&E, SCE, and SDG&E; unspent funds may be carried forward and spent in a subsequent year (including years beyond year four), but the total expenditure may not exceed $2.4 million.

**(END OF APPENDIX A)**

## APPENDIX B

## ADOPTED SCHEDULE FOR 2011 SOLICITATION

| LINE NO. | ITEM | NO. OF DAYS (cumulative) |
|---|---|---|
| 1 | Mailing of Commission decision conditionally approving 2011 RPS Plans | 0 |
| 2 | IOUs file amended RPS Plans | 14 |
| 3 | IOUs issue RFOs (unless amended Plans are suspended by Energy Division Director by Day 21) | 21 (a) |
| 4 | IOUs notify Commission that bidding is closed | 81 |
| 5 | Date IOUs notify bidders of shortlist; no exclusivity agreements may be required before this date | 123 |
| 6 | IOUs submit shortlists to Commission and PRG | 133 |
| 7 | IOUs file by Tier 2 advice letter (a) Evaluation Criteria and Selection Process Report and (b) Independent Evaluator's Preliminary Report | 163 |
| 8 | IOUs submit ALs with PPAs for Commission consideration (as necessary for earmarking) | 282 |

Note: The Energy Division Director may change these dates. Party requests for changes must be directed to the Executive Director (Rule 16.6).

(a) An IOU may adjust this date to a day after day 21, as necessary, without Commission approval.

**(END OF APPENDIX B)**

# APPENDIX C

## LINKS TO DRAFT 2011 PROCUREMENT PLANS AND SUPPLEMENTS TO INTEGRATED RESOURCE PLANS FOR RENEWABLES PORTFOLIO STANDARD PROGRAM

1. Pacific Gas and Electric Company

   http://docs.cpuc.ca.gov/EFILE/MISC/119090.htm

2. Southern California Edison Company

   http://docs.cpuc.ca.gov/EFILE/MOTION/120022.htm

3. San Diego Gas & Electric Company

   http://docs.cpuc.ca.gov/EFILE/REPORT/116582.htm

4. PacifiCorp

   http://docs.cpuc.ca.gov/EFILE/MISC/111935.htm

5. California Pacific Electric Company, LLC
   (formerly Sierra Pacific Power Company)

   http://docs.cpuc.ca.gov/EFILE/MISC/111864.htm

**(END OF APPENDIX C)**

**APPENDIX D**

**SUMMARY OF CHANGES PROPOSED BY IOUS IN 2011 PLANS**

The three large IOUs propose several changes for their pro forma contracts. The major changes identified by the IOUs are summarized here.

**PACIFIC GAS AND ELECTRIC COMPANY**

As described by PG&E, changes include but are not limited to:

- delay in online date;
- guaranteed energy production;
- commercially reasonable efforts to maintain eligible renewable resource status;
- updated insurance provisions;
- clearer delineation of buyer and seller responsibilities for CAISO Eligible Intermittent Resource Program (EIRP) costs; and
- modifiable standard terms and conditions.

PG&E also proposes several other changes. These include:

- require sellers located outside the CAISO balancing area to provide more detail about how they plan to deliver energy to the CAISO grid;
- require sellers to identify if the project is located in a renewable energy zone associated with the Regional Transmission Planning Initiatives (RETI), Western Renewable Energy Zone (WREZ) or other comprehensive and official resource study effort;
- limit number of project offers PG&E will accept from each seller to no more than 5 projects (or more than 5 projects if the aggregate total is less than 200 MW);

- extension of time for sellers to post offer deposits, with a modified definition of Letter of Credit;

- requirement that bidders submit a detailed term sheet with the initial offer that identifies key commercial terms and conditions with PPA modifications sought by bidder (eliminating the requirement that bidders submit a marked-up form PPA with the initial offer);

- remove the requirement that PPA purchase options be at a fixed price only at years 5 and 10 but may be at fair market value at dates proposed in the offer;

- limit joint development and ownership proposals to those located within California using commercially proven technologies; and

- require more complete information with joint development and ownership proposals.

**SOUTHERN CALIFORNIA EDISON COMPANY**

As described by SCE, changes include but are not limited to:

- Non-disclosure Agreement (NDA) Procedure: SCE will now require sellers to agree to a "short-term NDA" (which generally covers matters up to the date of the shortlist, with those items then held confidential for 5 years), rather than negotiate an NDA before the bids are evaluated;

- Deletion of Alternate Wind Performance Standard: SCE will present and explain the alternate wind performance standard during negotiations rather than post the alternate on SCE's website and in solicitation materials (since SCE has found most sellers do not use the alternate);

- Procurement Protocol: added seller's breach of exclusivity agreement as a condition for forfeiture of a short list deposit; requires proposals with terms longer than 20 years to also include a

20 year term (to assist in proposal comparison); states preference for facilities whose first point of interconnection within Western Electricity Coordinating Council (WECC) is with a California balancing authority (while still open to considering proposals from out-of-state facilities);

- Form of Seller's Proposal: requires bidders to submit proposals electronically in an e-binder rather than printed copies; requires greater bid specificity of delivery point, detail for transmitting energy to delivery point, and explanation of whether delivery costs are in energy price; requires disclosure of possible equipment availability constraints;

- Seller's Acknowledgements: clarification of language that seller will obtain approvals of PPA with SCE at the conclusion of negotiations (not by the time bidder first submits proposal); modified language to require seller to negotiate with SCE in good faith (rather than be bound by a redlined proposed PPA; the redlined PPA has been replaced with a required outline of contract terms and conditions setting forth key changes seller seeks in PPA); elimination of requirement that seller submit CEC audits regarding ERR status (audits are addressed in the PPA);

- Seller's Proposal Template and Calculator: integrated revenue calculator into Seller's Proposal Template and Calculator; require each proposal to provide contract prices based on curtailment caps;[1] required some additional information and eliminated other information no longer needed;

- PPA: require sellers to invoice SCE monthly to receive payment; narrowed the circumstances under which a "compliance expenditure cap" applies (e.g., dollar limit on seller's costs to

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[1] As each IOU must do relative to all decisions in this order, we specifically point out that SCE must modify this portion of the Seller's Proposal Template and Calculator to align with our decisions on economic curtailment elsewhere in this order.

maintain certain characteristics due to a change in law); changes the Energy Replacement Damage Amount penalty calculation from being based on "market" prices (dominated by conventional generation resources) to "green market" prices (i.e., price for renewable generation resources); added language to specify proper allocation of roles and responsibilities of SCE (as scheduling coordinator for purposes of North American Electric Reliability Corporation (NERC) compliance) and seller (as the generator operator); revised language so SCE may terminate the PPA and retain development deposit under any one of six circumstances (to eliminate a termination right disfavored by lenders while ensuring the SCE can terminate projects unlikely to be built); requiring seller to specifically state before contract execution whether seller will seek an investment tax credit, production tax credit, or no tax credit; divided into two sections the right of either party to terminate when seller fails to obtain permits (to better allow individually-tailored time periods); allocation of Standard Capacity Product incentive payments and charges defined in CAISO tariff;[2] modified energy payment calculation formula relative to delivery losses to mirror current CAISO MRTU market; modified wind and solar performance requirements; modified indemnification obligations to more clearly reflect different duties, responsibilities and risks of SCE and sellers; removed requirement that seller provide its financial information for purposes of consolidating seller's financial information into SCE's financial statements (given June 2009 changes by Financial Accounting Standards Board (SFAS 167 Amendments to FASB Interpretation No. 46(R)) regarding conditions associated with consolidation); modified data collection regarding seller's estimate of lost output and SCE right to verify data.

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[2] As each IOU must do relative to all decisions in this order, we specifically point out that SCE must modify this portion of the Seller's Proposal Template and Calculator to align with our decisions on SCP incentive payments elsewhere in this order.

**<u>SAN DIEGO GAS & ELECTRIC COMPANY</u>**

As described by SDG&E, changes include but are not limited to:

- LCBF Ranking Price: Adjusted to use above market funds (AMF) Calculator (which values a bid's cost relative to MPR and takes into consideration applicable delivery profiles and TOU factors); not use TOD Adder (since AMF Calculator includes adjustments for TOD factors), RA Adder (since proposed TOD factors include some capacity valuation), Duration Equalizer Adder (since experience shows no material impact on outcomes);

- LCBF Very Short Term Offers: Will use price reasonableness benchmark methodology for very short-term RPS (to conform with D.09-06-050);

- Pricing Forms: Revised to capture bidders' suggestions, automate certain inputs, reduce bidder errors (making bid forms simpler and more user-friendly);

- RFO: Continue utility-owned generation consideration, but not in RFO seeking bids (to fulfill code of conduct obligations in D.07-12-052);

- RFO: Increase minimum project size for projects in SDG&E's area from 1.5 MW to 3.0 MW if SB 32 implemented (allowing FIT to accommodate smaller projects); and

- Proforma PPA: Make selected terms defined terms and correct grammar errors (for consistency).

**(END OF APPENDIX D)**

D.11-04-030
R.08-08-009

**Concurrence of Commissioner Timothy Alan Simon**
**Decision Conditionally Accepting 2011 Renewables Portfolio Standard Procurement Plans and Integrated Resource Plan Supplements**

*Introduction*

This Decision[1] makes a number of important improvements and updates to our renewable procurement planning requirements for Investor-Owned Utilities and Multi-Jurisdictional Utilities, and thus marks another step forward in California's Renewable Portfolio Standard (RPS) programs. In particular, I am pleased that we are incorporating a greater level of specificity and utility control in the provisions of economic curtailment and related modifications to pro-forma contract terms.[2] Another essential element of this Decision is the required use of integration cost adders associated with ancillary services to ensure greater reliability in lieu of increased variability in generation and/or load.[3] However, in concurrence with this Decision, on a forward looking basis I want to ensure that the California Public Utilities Commission (CPUC) incorporates additional economic considerations in our RPS procurement planning process and "Least Cost Best Fit" contract evaluations.

*Evaluating the Impacts of Renewable Targets on the California Economy*

In the signing ceremony of SB2x[4] Governor Edmund Brown, Jr. reiterated that 33 percent is the floor and not the ceiling of renewable procurement, and accordingly envisions 40 percent as an achievable RPS

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1 Decision Conditionally Accepting 2011 Renewables Portfolio Standard Procurement Plans and Integrated Resource Plan Supplements (D.11-04-030), April 14, 2011.

2 *Id.* At 12-13.

3 *Id.* at 22.

4 Senate Bill 2x (Simitian, D-Palo Alto), signed into law on April 12, 2011, raises California's Renewable Portfolio Standard target to 33%.

goal.[5] I support this ambitious long-term objective, but we must remain vigilant that we balance our environmental goals with a healthy economy. This mandate will require a more selective process by the CPUC in examining the quality and cost-effectiveness of individual contracts that we approve. This is imperative to meet the energy needs of California's commercial and industrial customers, which could see substantial increases in electricity bills if we fail to foster adequate competition in our renewable portfolio. I have concerns that increased electricity costs and limited Direct Access could result in job losses, even as clean technology development in California is premised in part on the hope of increased economic activity. Accordingly, a heightened focus on energy efficiency and demand response technologies is critical to California achieving a balance between greenhouse gas emissions reductions and competitive advantage in attracting and retaining business opportunities. To this end, I remain concerned that our rapid pursuit of renewable generation is overly incremental and ad hoc in deployment.

***Tracking the True Cost of Renewable Generation***

To achieve a cost effective and balanced energy mix we must evaluate the full fuel cycle costs of renewable generation when weighing incremental procurement choices. As we examine firming and shaping needs for renewable generation, we cannot ignore the magnitude of shale gas discoveries across the U.S. and the positive impact this can have on the full fuel cycle cost of clean energy alternatives. For instance, when combined with other domestic shale gas supplies, the Utica[6] and Marcellus shale plays could offer up to 200 years of natural gas supply. Shale exploration is not without controversy, as the hydraulic tracking debate continues. With effective environmental management of exploration, vast gas supplies may give a low cost energy advantage to competing states.

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[5] *See* http://www.latimes.com/news/local/la-me-renewable-energy-20110413,0,3118203.story for details about Governor Brown's speech at the signing ceremony in Milpitas, California on April 12, 2011.

[6] *See* discussion of Utica and other shale formations at http://oilshalegas.com/uticashale.html.

Additionally, as we explore and advance energy storage options,[7] it is clear that a comprehensive policy on fuel options is critical.

***New Targets, New Technological and Economic Considerations***

Our new legislative mandates[8] require increasingly complex analyses of alternative supply- and demand-side energy resources in our long-term procurement planning processes.  While I am very supportive of our continued RPS development, I challenge this Commission and staff to expand our understanding of the comprehensive costs of California's clean tech pursuits.  In doing so, I believe we will establish the discipline necessary to carefully weigh all procurement options by considering some of the practical results and consequences of our decisions on the welfare of all customer classes.  Accordingly, I concur with this Decision, and look forward to monitoring our progress as renewable procurement evolves and presents challenges in our broad long-term procurement planning process.

Dated April 19, 2011, at San Francisco, California.

/s/  TIMOTHY ALAN SIMON
Timothy Alan Simon
Commissioner

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[7] Order Instituting Rulemaking Pursuant to Assembly Bill 2514 to Consider the Adoption of Procurement Targets for Viable and Cost-Effective Energy Storage Systems (R.10-12-007) issued December 21, 2010.

[8] SB2x requires that we reach 20% renewables by the end of 2013, 25% renewables by the end of 2016, and 33% by the end of 2020.