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Decision 07-02-011 February 15, 2007

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

OPINION CONDITIONALLY ACCEPTING PROCUREMENT PLANS FOR 2007 RPS SOLICITATIONS

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1. Summary

As part of the California Renewables Portfolio Standard (RPS) Program, each California electrical corporation or retail seller, with limited exception, is required each year to procure a minimum quantity of electricity from eligible renewable energy resources. The amount must increase by at least 1% each year, and reach 20% of total retail sales no later than 2010. As part of fulfilling this requirement, each electrical corporation must prepare a renewable energy procurement plan (Plan). The Commission is required to review and accept, modify or reject each Plan.

In this order, we conditionally accept the proposed Plans filed by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E). In doing so, the important steps we take include:

1. **Specific Proposals**: Accept or reject several specific proposals (see Appendix A for a more complete list), such as:

    a. Accept PG&E's proposals to reduce a portion of its Project Development Security, and include solicitation of "sites for development."

    b. Accept SCE's proposal to offer Scheduling Coordinator (SC) services within an established bandwidth of the generator's operation, but decline to order other investor-owned utilities (IOUs) to offer this service.

    c. Adopt proposals for all three IOUs to: (i) require certain financial disclosures only after a project is on an IOU's shortlist; (ii) implement certain changes relative to Senate Bill (SB) 107; and (iii) direct each IOU to continue to improve its

Plan, including its statement of evaluation criteria and selection process.

d. Reject a proposal to permit consideration of cost recovery of debt equivalence and other costs through an advice letter.

2. **General Direction**: Encourage, or repeat our encouragement, of IOUs to consider or reconsider:

   a. All deposit and collateral policies and amounts to reach an efficient and equitable balance.

   b. The extent of required project-specific financial information.

   c. Inclusion of a "change in law" clause in the model contracts.

   d. The tone and nature of waiver and disclosure requirements.

   e. The building of RPS facilities, to the extent necessary or desirable, to permit reaching RPS Program goals within existing Commission-approved long term procurement processes and guidelines, including the possibility of soliciting development sites, as does PG&E.

   f. Continuing improvements to each Plan, including the form and format.

3. **Commission Process**: Continue existing Commission practice for review of proposed RPS contracts by advice letter, and point out Energy Division's existing and ongoing role to reject or reclassify some advice letters, as appropriate.

4. **Schedule**: Adopt a (i) schedule for completing the 2007 solicitation cycle (see Appendix B), and (ii) process for initiating the 2008 solicitation cycle.

PG&E, SCE and SDG&E shall each submit an amended Plan. The amended Plan shall be submitted to the Director of the Energy Division within

15 days of the date this order is mailed. Unless suspended by the Energy Division Director within 22 days of the date this order is mailed, each utility shall proceed to use its amended Plan for its 2007 RPS program and solicitation.

We continue to employ the presumption that utilities are able to use their business judgment in running their solicitations, with the guidance we provide and within the parameters we establish. 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 IOU implements the orders adopted herein, elects to take the guidance provided herein, demonstrates creativity and vigor in program administration and execution, and reaches program targets and requirements.

This proceeding remains open to address specific additional matters. These include policy issues identified in the August 21, 2006 Scoping Memo; compliance reports which have been, or will be, filed in 2007; enforcement matters which may arise; and other issues, to the extent either identified in the initial Scoping Memo or a later amended Scoping Memo.

2. Procedural Background

SB 1078, effective January 1, 2003, established the California RPS Program.[1] Several Plans have been considered, and solicitations held, under the program.

The August 21, 2006 Scoping Memo and Ruling of the assigned Commissioner set a schedule for consideration of the draft 2007 RPS Plans. On

[1] Stats. 202, Ch. 516, Sec. 3, codified as Pub. Util. Code §§ 399.11, *et seq*. All subsequent code section references are to the Public Utilities Code unless noted otherwise.

or about September 25, 2006, PG&E, SCE and SDG&E each filed and served its proposed 2007 RPS Plan. On October 16, 2006, comments were filed and served by the California Wind Energy Association (CalWEA), The Utility Reform Network (TURN), and the Commission's Division of Ratepayer Advocates (DRA). On October 23, 2006, reply comments were filed and served by PG&E, SCE and SDG&E.

Separately by ruling dated September 14, 2006, but concurrently with the above events, the requirement to file draft RPS plans was further explained and limited (i.e., limited from all respondent IOUs to the three largest IOUs). In addition, parties were provided an opportunity, at SCE's request, to again address whether or not electric service providers (ESPs) should be required to file draft 2007 RPS Plans. On September 21, 2006, comments were filed by SCE, the Alliance for Retail Energy Markets (AReM), and City and County of San Francisco (CCSF). On September 26, 2006, reply comments were filed by AReM. By ruling dated October 11, 2006, the earlier order limiting the filing requirement to the three largest IOUs was affirmed.

By ruling dated November 9, 2006, each of the three largest IOUs was directed to file additional information. This information involves the effect, if any, on its draft 2007 RPS Plan of RPS Program changes effective January 1, 2007, pursuant to the passage of SB 107. Each IOU was asked to address possible changes in four areas: renewable energy credits (RECs), agreement information, access to bid information, and anything else necessary for Commission consideration. On November 21, 2006, responses were filed by PG&E and SCE. On November 26, 2006, comments were filed by Central California Power (CCP). On December 6, 2006, a response was filed by SDG&E. On December 7, 2006, comments were filed by CCP on SDG&E's response.

The adopted schedule provided various dates for parties to move for evidentiary hearing. No party filed a motion for hearing, and no hearing was held.

3. Overview of RPS Program and 2007 Plans

Pursuant to the RPS Program, each electrical corporation and retail seller is required each calendar year to procure, with some exceptions, a minimum quantity of electricity from eligible renewable energy resources as a percentage of total retail sales. This is generally known as the annual procurement target, or APT. Each electrical corporation 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 incremental growth in the APT. (§ 399.15.)

To fulfill these requirements, each electrical corporation must prepare a Plan for the procurement of renewable 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 compliance flexibility mechanisms established by the Commission, and (c) a bid solicitation. The Commission must review and accept, modify or reject each electrical corporation's Plan prior to the commencement of renewable resource procurement. (§ 399.14.)

Pursuant to the August 21, 2006 Scoping Memo, each IOU submitted its 2007 Plan on or about September 25, 2006. Each Plan describes the actions the IOU will undertake in order to meet its 2007 APT, 2007 IPT and other RPS targets as it proceeds to ultimately procure 20% of its retail sales from eligible renewable resources by 2010. Each Plan includes resource planning information, a protocol or a request for offer (RFO), and one or more master purchase and sale agreements. The Plans are briefly described below.

3.1. PG&E

PG&E estimates its 2007 APT is about 11,687 gigawatt-hours (gWh), and its 2007 IPT is approximately 750 gWh.[2] In its 2007 Solicitation, PG&E seeks to procure approximately 1% to 2% of its retail sales volume, or approximately 750 to 1,500 gWh.

PG&E states that, starting in 2007, it will require more capacity to meet its reserve margin requirements, as well as additional peaking energy resources to meet its net energy requirements. After 2007, PG&E says it will require additional dispatchable peaking and shaping resources to meet energy and capacity requirements for all subperiods. PG&E reports that it is particularly interested in projects that will begin commercial deliveries during 2008, given that a significant number of deferred incremental deliveries (otherwise due in 2004 and 2005) are now due in 2008.

PG&E's proposed 2007 Plan and draft master purchase and sale agreements are similar to those used in 2005 and 2006. PG&E seeks Power Purchase Agreements (PPAs) with delivery terms of 10, 15 or 20 years beginning in 2007 or beyond. Participants may also propose delivery terms between 10 and 20 years. Participants may submit offers for four specific products: (a) as-available, (b) baseload, (c) peaking, or (d) dispatchable. PG&E states that it will also consider two types of combination products: (a) peaking or

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[2] PG&E's 2007 Procurement Plan, page 6. This is an APT of about 1,668 average megawatts (aMW) at an 80% capacity factor (CF). This is an IPT of about 107 aMW at an 80% CF.

dispatchable plus as-available, or (b) peaking plus other firm deliveries in any combination of other time-of-delivery (TOD) periods.

In addition to purchases, PG&E will also consider three ownership alternatives. These are: (a) purchase and sale agreement (in which the developer sells the project to PG&E for a pre-determined price at the time the project enters commercial operation), (b) a PPA with PG&E buyout option (in which the developer gives PG&E the option to purchase the facility at a pre-determined price after it has been in operation for a certain number of years), and (c) sites for development (in which a participant offers a new or existing site controlled by participant (with land rights assigned to, or purchased by, PG&E) for PG&E to, in turn, develop, construct and operate an RPS facility).

PG&E states that it will evaluate offers using several factors. These are: (a) market valuation, (b) portfolio fit, (c) credit and finance, (d) project status, (e) technology viability and participant experience, (f) supplier diversity, (g) adjustment for transmission cost adders and integration costs, and (h) materiality and cost impact of any proposed modification to the standard contract.

PG&E assumes the regulatory environment in 2007 will be substantially the same as before, except for new RPS provisions as a result of SB 107, effective January 1, 2007. PG&E identifies six differences between its 2006 and 2007 proposed solicitations:

1. Updated TOD factors (based on recent forward market prices for natural gas and wholesale power).

2. An expanded Dispatch Down Period (wherein PG&E may curtail a unit upon request up to 50 hours per year in order to improve integration of facilities with overall operations).

3. Reduction of collateral requirements during project development (retaining adequate collateral to encourage performance but reducing requirements on projects with smaller capacity factors, on a megawatt-hour (mWh) basis).

4. Request that participants whose projects have delivery points outside the California Independent System Operator (CAISO)-controlled grid provide two separate prices (one for delivery onto the CAISO grid, and one for delivery outside the CAISO grid).

5. Elimination in redundancy of evaluation protocols.

6. Terms are conformed to changes in statute pursuant to SB 107.

PG&E estimates that it will meet its 2007 IPT, but may not achieve its 2007 APT, and may need to utilize flexible compliance to meet that obligation. Further, PG&E estimates it will meet its 2010 APT, but may need to use flexible compliance provisions, given that construction of new facilities will take time and delay the commencement of deliveries for a period of several years after contract execution.

3.2. SCE

SCE estimates its 2007 APT is 14,998 gWh, and its 2007 IPT is 779 gWh.[3] SCE states that its 2007 planned procurement activities include seeking resources to augment those under contract as a result of prior solicitations, and those executed as a result of the 2005 and 2006 solicitations, to the extent necessary to ensure that SCE meets the overall 20% goal.

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[3] SCE's 2007 Procurement Plan, Attachment 1. This is an APT of about 2,140 aMW at an 80% CF. It is an IPT of about 111 aMW at an 80% CF.

SCE says it has received relatively few bids that do not require significant transmission upgrades for delivery of the energy. Transmission will continue to be a serious impediment, according to SCE, and increased procurement activity (e.g., executing more contracts) will not accelerate the planning, permitting and construction of necessary transmission. Unlike its 2006 Plan, SCE's 2007 Plan does not develop high, medium and low procurement need scenarios based on a range of forecasts for key variable (e.g., retail sales). Nonetheless, SCE says its overall goal is to achieve 20% as soon as possible.

SCE's 2007 Plan and protocol are similar to those in 2006. SCE says it will consider timely proposals from existing or new projects located within or outside California. These include new or repowered facilities that operate on co-fired fuels or a mix of fuels that include fossil fuel hybrid. SCE seeks proposals based upon standard term lengths of 10, 15 or 20 years, and each proposal must be at least one megawatt (MW). SCE prefers delivery at SP-15,[4] but will consider other proposals.

SCE says it will evaluate proposals based on criteria intended to achieve the lowest ratepayer cost and the best fit with utility retained generation and California Department of Water Resources generation. SCE states that it takes into account the criteria in the Commission's least-cost best-fit (LCBF) decision (D.04-07-029). For example, SCE indicates that quantitative benefits and costs are incorporated into proposal-specific benefit/cost ratios used to rank proposals,

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[4] Path 15 is a transmission interface located in the southern portion of PG&E's service area that is in the middle of the CAISO control area. It is comprised of several high voltage lines, and runs approximately 90 miles between the Los Banos and Gates substations in the San Joaquin Valley. SP-15 is the zone south of Path 15. (D.03-05-083, pp. 11-12.)

with qualitative attributes used to screen and adjust final ranking. Quantifiable values are evaluated using a production simulation model to calculate total system production costs and benefits associated with the renewable generating facility, and capacity benefits are developed by incorporating Effective Load Carrying Capacity values, according to SCE. Quantified costs also include transmission, integration and debt equivalence. Non-quantified attributes include seller's capability to perform, seller experience, seller technical expertise, and environmental impacts. Finally, SCE says it will utilize attributes identified by the Commission in D.04-07-029 as qualitative methods for evaluating tie-breakers.

SCE identifies the following significant differences between its 2006 and 2007 proposed Procurement Plans:

1. Scheduling Coordinator (SC)

    a. SCE will provide SC services.

    b. SCE includes disposition of CAISO charges and a penalty in order to allocate costs relative to SCE providing these services.

2. Wind Projects

    a. SCE includes new performance standards to allow sellers to adjust proposed prices and address elimination of commercially available wind turbine manufacturer guarantees.

    b. SCE includes new standards for meteorological equipment to address changing standards for this equipment.

SCE estimates that it may neither achieve its 2007 IPT, nor its 2007 APT, absent application of flexible compliance rules. Nonetheless, SCE's goal is to achieve 20% as soon as possible, whether or not that goal can be accomplished by 2010. SCE reports that it is positioned to meet the goal by 2013, if not before. (SCE Plan, pp. 2 and 5.)

3.3. SDG&E

SDG&E states that its 2007 APT is 905 gWh, and its 2007 IPT is 164 gWh.[5] SDG&E says it expects to exceed both its 2007 APT and IPT, and will bank surpluses for future compliance. SDG&E anticipates achieving the goal of procuring 20% of its retail sales via renewables by 2010. In addition, however, SDG&E says that results from the 2004 and 2005 RFOs validate SDG&E's concerns that availability of transmission will have a significant impact on SDG&E's ability to achieve the 20% by 2010 goal, particularly new transmission that may be needed to import energy from Imperial Valley, Tehachapi and eastern San Diego County.

SDG&E says its RFO will solicit capacity and energy services from repowered generation, upgraded plant, or new facilities, and the RPS products may include unit firm or as-available deliveries starting in 2008, 2009, 2010 or 2011. SDG&E seeks proposals for 10, 15 or 20 years, but will consider other contract durations subject to Commission approval. The 2007 RFO allows sellers to offer renewable products from generation plants connected anywhere in the

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[5] SDG&E's 2007 Plan, page 4. This is an APT of about 129 aMW at an 80% CF. It is an IPT of about 23 aMW at an 80% CF.

Western Electricity Coordinating Council (WECC) transmission system, as long as the energy is delivered into California.

SDG&E indicates that it also intends to evaluate a number of ownership opportunities. These include turnkey development, PPAs with ownership options after commercial operation, and building its own renewable generation.

SDG&E says that bids will initially be ranked based on an all-in price, including costs or credits related to capacity, energy, transmission upgrades, congestion, and integration. Bids will also be ranked, according to SDG&E, based on duration equalization adders and debt equivalence adders, if applicable. SDG&E indicates it will use production cost modeling to evaluate LCBF from offers that have made its short list. Qualitative factors will be used as tie-breakers of similar cost offers, according to SDG&E, including such factors as benefits to minority and low income areas, resource diversity, environmental stewardship (including the Commission Water Action Plan), ability to advance the schedule for commercial operation, technology and operational flexibility, reliability, development risk, financing plan, corporate capabilities, credit and proven experience.

SDG&E intends to issue an RPS RFO in 2007. Further, SDG&E reports that it has made it a practice, to the extent feasible, to include renewables in non-RPS RFOs. SDG&E says it may do so again if it issues an all-source RFO during 2007.

SDG&E explains that RPS contracts may affect SDG&E's credit rating due to the effects of debt equivalence and financial reporting consolidation potentially required under FIN 46(R) rules.[6] In recognition of possible costs from

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[6] Financial Accounting Standards Board Interpretation No. 46(R), referred to as FIN 46(R). SDG&E says no PPA has been deemed subject to consolidation until now

Footnote continued on next page

this reduced credit rating, SDG&E requests Commission authorization to recover costs associated with rebalancing its capital structure to the authorized capital structure. SDG&E proposes to do this by seeking relief in advice letters filed with the Commission for approval of individual RPS contracts.

SDG&E identifies several changes between the 2006 and 2007 Plans, the more significant being:

1. Clarification regarding acceptance of offers from anywhere in the WECC system as long as the energy is delivered to a CAISO delivery point.

2. Clarification regarding how bids are evaluated and ranked as part of the LCBF process.

3. Consideration of SDG&E building its own plants by 2010.

4. Clarification regarding bidders submitting two bids when the project relies on any third party awards (e.g., Supplemental Energy Payments (SEPs), Production Tax Credits, Investment Tax Credits), with one price if funding is available, and one price if funding is unavailable.

4. Issues Common to All Plans

We have, in fulfilling our duties and allowing electrical corporations to fulfill theirs, granted RPS-obligated electrical corporations considerable flexibility in the way they satisfy RPS program goals. For example, we have generally employed the presumption that utilities should be permitted to use

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but new, more restrictive financial reporting rules may increase instances wherein SDG&E must consolidate a seller's financial information with SDG&E's own financial reports to the Securities and Exchange Commission. (Plan, p. 19.)

their best business judgment in running their solicitations, unless their plans threaten to impair the effectiveness of the RPS program. In this context, we have provided guidance, and adopted limited and specific program requirements. We have also taken steps to broaden and enhance the quantity and quality of RPS bids and improve the contracting process. (See, for example, D.05-07-039, p. 15; D.06-05-039, p. 14.) We continue to do so here by providing additional guidance, taking limited actions to further expand opportunities, and adopting a schedule to organize the process for 2007.

We do this based on relatively limited comments from parties on the IOU's proposed 2007 Plans. Parties generally do not recommend extensive changes in proposed Plans. In fact, CalWEA states that: "the utilities' 2007 procurement plans and solicitation documents reflect incremental improvement over prior years' materials." (Comments, p. 1.) Nonetheless, three parties raise several concerns, and we note others, which we address below.

At the same time, we reaffirm that each RPS-obligated retail seller ultimately has the duty to take all reasonable actions to meet the state's RPS goals. Our responsibility includes reviewing the results of solicitations, and accepting or rejecting proposed contracts submitted for approval, based on consistency with approved Plans. (§ 399.14(d).) The Plans approved herein will be a fundamental, but not necessarily the only, part of that review, as described in prior decisions, including D.06-05-039, and also below.

Moreover, while we review each Plan, our conditional acceptance is based on the fact that we have neither written each Plan, dictated with precise detail the specific language on each page of each Plan, nor do we take over procurement. These remain IOU Plans, subject to our guidance along with limited, focused and specific direction. The procurement duties remain those of each IOU. The IOU is ultimately responsible for proposing and obtaining approval of reasonable Plans, and achieving successful procurement under the RPS Program.

In this context, we address the following ten issues common to all plans in the noted sections below:

- 4.1: credit requirements and collateral pool
- 4.2: utility-owned projects
- 4.3: financial disclosures, rate adjustments and change in law
- 4.4. waivers and disclaimers
- 4.5: scheduling coordinator
- 4.6: evaluation criteria
- 4.7: changes pursuant to SB 107
- 4.8: Commission review process
- 4.9: Other changes to model contracts
- 4.10: RPS data

4.1. Credit Requirements and Collateral Pool

4.1.1. Background

At least three types of deposits or collateral may be sought by IOUs: with a bid, during project development, and during commercial operation. We addressed bid deposits in our consideration of the 2005 Plans. (D.05-07-039.) At that time, we had limited information and concluded we should not interfere with IOU's judgment, but urged parties to bring us more evidence, as needed.

In our consideration of the 2006 Plans, we summarized and addressed bid deposits and other collateral requirements (e.g., commercial operation security, performance assurance deposits). (D.06-05-039.) No party presented new information there, but we made several observations and encouraged IOUs to reconsider various amounts and conditions related to deposits and collateral. We also stated we would take the reasonableness and level of bid deposits into account should an electrical corporation later seek reduction or waiver of a non-compliance penalty, with the burden of the showing on the electrical corporation.

4.1.2. PG&E Proposal

PG&E now proposes to reduce a portion of its Project Development Security for as-available, baseload and peaking (but not dispatchable) products.[7] This, for example, reduces the Project Development Security by as much as half (from $20/kW to $10/kW).

No party opposes PG&E's proposal to reduce a portion of its Project Development Security. We accept PG&E's proposal.

PG&E's proposed 2007 Delivery Term Security (from the commercial operation date through conclusion of the contract) remains the same as in the 2006 Solicitation. It is an increasing amount as a function of months of revenue for increasing contract length.

CalWEA contends that all three IOUs seek an excessive amount of credit during project operations. CalWEA believes no independent financial performance assurance is needed once a project has achieved commercial operation. If, however, IOUs "want at least some 'skin in the game' from developers," then CalWEA recommends an amount equal to no more than two

[7] PG&E's Project Development Security is composed of (a) $3/kilowatt (kW) for the first period (between the date the agreement is executed and a date within 30 days following CPUC approval of the agreement) and (b) $20/kW for the second period (between 30 days after CPUC approval and the project's commercial operation date). PG&E now bifurcates the deposit in the second period to (a) for dispatchable products it is $20/kW and (b) for intermittent, baseload or peaking products it is $20/kW multiplied by the greater of (i) capacity factor or (ii) 0.5.

months' projected project revenue. (Comments, p. 2.) We decline to adopt this recommendation.

PG&E's proposed Delivery Term Security is 5% of the total revenues of the project (e.g., six months' revenue for a 10-year contract; 12 months' revenue for a 20-year contract). CalWEA proposes the commercial operation security be no more than 1.7% of total revenues over the contract life (e.g., two months for a 10-year contract). In support, CalWEA asserts that the 5% collateral requirement results in the IOUs being "over-insured" at the ratepayers' expense. Despite our request for evidence related to problems, if any, CalWEA provides no data in support. We are not persuaded to reduce the amount here, as recommended by CalWEA, particularly in light of the observations we discuss further below.

4.1.3. SCE Proposal

At SCE's option, SCE may select one of the following amounts for the collateral obligation during operation (called Performance Assurance by SCE): (a) zero dollars, (b) six months of contract payments based on maximum contract capacity or (c) 12 months of contract payments based on maximum contract capacity. (SCE 2007 Procurement Protocol, Appendix 2A, p. 24.[8]) Since one option is zero, in the case of SCE this appears to address CalWEA's proposal to require two months or less.

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[8] SCE also says that it "will only execute Power Purchase and Supply Agreements wherein Seller posts a Performance Assurance amount that is greater than zero (0) months of contact payments." (Id.) At the same time, many terms are negotiable, and the bidder might propose that the final Performance Assurance be equal to two months of contract payments or less.

Further, however, we note that SCE proposes each seller submit three contract prices, one each for the three Performance Assurance amounts. This may permit CalWEA (or another party) to collect information on the amount of "insurance" built into the contract price for each Performance Assurance. Absent credible information, however we decline to conclude whether or not the IOU's proposed operating collateral requirements under-insure, properly insure, or over-insure ratepayers or others.

4.1.4. SDG&E

SDG&E does not propose any changes in its credit requirements during project operation. For the reasons discussed below, we are not persuaded to adopt CalWEA's comments relative to SDG&E.

4.1.5. Observations

Thus, generally for the 2005 and 2006 Plans we had, and for the 2007 Plans we have, an inadequate record to order further modifications. Nonetheless, as we did before, we make several observations.

First, we continue to encourage IOUs to reconsider all deposit and collateral amounts and policies. To the fullest extent reasonable, IOUs must propose amounts and policies that reach a proper balance between all competing interests, such as the desire to stimulate the RPS market; the interests of ratepayers and the state in having viable projects bid, develop and operate in a reasonable, reliable and safe manner; and a reasonable balance of risks between all parties. Moreover, these amounts and policies might not be static, but may change over time with changing conditions.

Second, we repeat that we will take deposit and collateral requirements into account should an electrical corporation later seek to avoid an RPS Program non-compliance penalty. Because we provide IOUs reasonable flexibility here, an IOU later seeking deferral or waiver of a penalty has the burden to present a showing in support of that request. The showing must include evidence that its deposit requirements were at least as reasonable as those of PG&E, and did not prevent otherwise viable projects from coming forward at least for evaluation. (See D.06-05-039, mimeo., p. 38.)

Third, we are generally persuaded by PG&E and SCE that deposits and collateral have some role in ensuring projects are proposed, developed and operated in a manner consistent with the RPS program and signed contracts. In particular, operating collateral provides a project developer with a financial incentive to continue to perform under the contract. This can be important if then current market prices for electricity several years into the term of a contract are at that time above the contract price. The developer would otherwise have an incentive at that time to default on the contract. As SCE says:

> RPS contracts "are typically 10 to 20 years in length. Neither party is able to predict what is going to happen during the term of these agreements; however the buyer generally pays a fixed levelized price over the term of the contract. Thus, IOUs must have some remedy to protect customers from renewable generators attempting to terminate a PPA when market prices are to the customers' advantage (typically the latter half of the term of the agreement due to levelized pricing structure)… A credit assurance of two months' revenue is insufficient to provide that assurance." (SCE Reply Comments, p. 2.)

Risk and risk-sharing are a function of several elements of the contract. These elements include the price level and the price structure (e.g., whether nominal prices are levelized using a real or nominal carrying charge rate; whether subject to some form of periodic adjustment to market or an index). They also include contract provisions for default, performance requirements, termination payments, and other remedies. (For example, see PG&E 2007 proposed Solicitation Protocol, Attachment G, Form of Power Purchase and Sale Agreement, Article 5.) Risks and remedies may also depend upon whether the default is voluntary or involuntary.

We may address the issue of deposits and collateral again when we give further consideration to risk-sharing as one of the seven policy issues upon which parties have commented. (See August 21, 2006 Scoping Memo, Attachment A, Issue 2.) In relationship to proposed 2007 Plans, however, no party presents sufficient information regarding the most equitable and efficient package of contract elements to justify modification from the proposals of the IOUs.

Finally, we again urge parties to bring evidence of problems with deposits and collateral, if any, to our attention. Parties should also continue to present information on the equitable and efficient package of contract elements to address risk and risk-sharing concerns. Absent a persuasive showing otherwise, however, we are likely to allow IOUs reasonable flexibility here. For example, absent compelling evidence otherwise, operating collateral of 5% does not appear unreasonable. Nonetheless, the burden is on IOUs to meet RPS Program targets, including 20% by 2010. We provide IOUs reasonable latitude in determining how they wish to reach the goal but will hold IOUs to successfully reaching that target (within flexible compliance rules).

4.1.6. Collateral Pool

PG&E recommends further exploration of a promising topic: a risk (or collateral) pool. According to PG&E, such pool could be a means of reducing costs and burdens of credit requirements for all renewable counterparties. PG&E says the Commission could set an aggregate number for collateral to protect against potential credit losses experienced by the pool. PG&E explains that each pool member would post collateral (or a guarantee) to cover an allocated portion of the aggregate requirement, and collateral held in the pool would be used to mitigate losses, if any.

PG&E's general concept has merit. Beyond simply endorsing PG&E's suggestion of seeking more information, however, the concept is not sufficiently developed to adopt and implement here.

Nonetheless, as noted above, SCE's requirement for all bidders to state three prices based on the amount of Performance Assurance likely supports the assertion that bidders seek recovery of collateral in prices. At least in theory, pooling of risk might be a less costly and more efficient method to address this issue. Several questions must be considered, however, before any proposal is adopted. Is there a role for government in establishing a framework in which private industry may provide this product? Alternatively, should this be a government-sponsored pool? Should participation by RPS generators be voluntary or mandatory? Should some portion of the authorized price for RPS energy be used to fund such a pool? Should public interest funds (e.g., SEPs) be set aside for this purpose, for the benefit of the entire program? What losses would be eligible for recovery from the pool? What criteria would be used for disbursing payments from the pool? Are there equity and efficiency gains by individual contract prices "internalizing" collateral requirements rather than incurring administrative and legal complications related to establishing a pool?

We will not direct respondents to develop a proposal. Nonetheless, we encourage respondents and/or parties to consider the subject and make a concrete proposal for our consideration here or in the long-term procurement plan proceeding (Rulemaking (R.) 06-02-013) if one or more parties believe it has merit.

4.2. Utility-Owned Projects

CalWEA renews its objection to counting energy from utility-owned renewable facilities toward meeting RPS goals. In support, CalWEA says competitive activities by IOUs may chill development by independent power producers, and discredit the RPS program due to concerns with utility gaming of the market. CalWEA says IOUs should not be encouraged to pursue direct ownership until completion of a public comment process. We disagree.

4.2.1. IOUs Should Consider Building

We addressed the matter last year in our review of the 2006 RPS Plans. CalWEA's repetition of an earlier comment does not convince us to alter course. Our prior statement remains succinct and clear. We adopt it again:

> "We intend to enforce the 20% by 2010 requirement. In doing so, we will take into account whether or not each electrical corporation undertook all reasonable actions to comply. One of those actions is building, then owning and operating, the resource itself. Utility construction of generation resources, of course, must be fully consistent with all Commission procurement rules (e.g., all-source solicitations; see D.04-12-048). We do not here require utilities to build resources. We only observe that the option should be considered.
>
> The burden is on the electrical corporation to comply with the RPS program, subject to certain compliance flexibility. Compliance must be met, subject to compliance flexibility and absent valid reasons otherwise. By adopting the amended Plans herein, we point out that the absence of discussion in the 2006 Plans about a utility building, owning and operating the renewable resource does not excuse an IOU from compliance on the basis that it did not build the plant itself, absent a valid reason otherwise.
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> Finally, we point out that a utility may build a renewable resource and, under appropriate circumstances, earn between 0.5% and 1.0% increased rate of return on that investment. (§ 454.3.) That is, the

> Legislature has authorized an increased incentive for utility ownership of renewable generation. We think IOUs should consider taking advantage of this law and, where reasonable and appropriate, we will authorize the increased rate of return." (D.06-05-039, p. 34.)

We are pleased to see PG&E include an item in its proposed 2007 RPS Protocol for solicitation of "sites for development." (PG&E Draft Solicitation Protocol, p. 9.) Through this item PG&E seeks offers for new or existing sites to "be acquired by PG&E for the development, construction, and operation of an ERR [eligible renewable energy resource]." (*Id.*, p. 9.) We accept PG&E's proposal.[9] We encourage (but do not order) SCE and SDG&E to adopt a similar item.[10]

We share DRA's concern, however, that IOUs may not be doing enough to consider building their own renewable resources. To explore the issue, the assigned Commissioner directed each IOU to include in its proposed 2007 Plan a "showing on [its] current consideration of whether or not to build its own

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9 PG&E did not propose "sites for development" in its 2006 RPS Protocol. (Solicitation Protocol, December 22, 2005, pp. 2-5.) Rather, PG&E there included ownership Alternatives I (Power Purchase Agreement with PG&E Buyout Option) and II (Turnkey Agreement). PG&E's amended 2006 Plan, submitted based on guidance and direction in D.06-05-039, included Ownership Alternative III (Sites for Development). (Solicitation Protocol, June 16, 2006, p. 10.)

10 We generally direct in only limited ways the manner in which an IOU achieves RPS Program goals (e.g., some standard terms and conditions in contracts). Rather, within the legislative framework, adopted program structure and our guidance, it is fundamentally up to each IOU to determine how it wishes to achieve the goals. Each IOU must, for example, propose a reasonable Plan for acquiring RPS resources. We accept, modify or reject each Plan. (§ 399.14(c).) Each IOU will then be held to meeting the goals, within rules for flexible compliance.

renewable generation to reach 20% by 2010 (D.06-05-039, pp. 33-34)." (August 21, 2006 Scoping Memo, Attachment C, p. 2.) PG&E and SDG&E report that they are considering the option, but the showings are limited and without many specifics. We expect more.

In particular, we note (as we similarly did last year) that minimal discussion in an RPS Plan about a utility building a renewable energy resource does not itself excuse an IOU from compliance with RPS goals. Our conditional acceptance of these Plans does not constitute a finding that each IOU has undertaken all reasonable actions to comply with RPS Program goals. We do not here require utilities to build resources. Nonetheless, we encourage IOUs to actively assess the feasibility of utility ownership, and pursue such ownership when and where it makes sense. We are unlikely to look favorably on a showing prepared in 2010, for example, regarding whether the IOU should have built plant earlier in the decade. Rather, we think the most convincing showing, if any, would likely include information created contemporaneously with each annual RPS Plan.

4.2.2. SCE's Concern about Asymmetric Rate Treatment

SCE states that a major obstacle exists in its pursuing the possibility of building its own RPS generation. According to SCE, the Commission in D.04-12-048 established an asymmetric cost sharing mechanism for utility construction of new generating resources. In particular, the Commission determined that 100% of actual utility construction cost above a utility bid-price must be paid by utility shareholders, but 50% of any savings below the utility bid-price is shared with ratepayers. SCE reports that its request for rehearing has been granted in part, and that until the 50/50 sharing mechanism is reheard

SCE "is practically prevented from pursuing utility built renewable generation." (Reply Comments, p. 16.)

To the contrary, the Commission routinely balances competing interests in making its decisions. We have balanced various interests and determined that the proper balance here is 100% shareholder funding of overages, and 50/50 sharing of savings. Unless changed on rehearing, this is the Commission's decision.

We encourage SCE not to assume it is immune from a possible non-compliance penalty simply because it disagrees with the Commission here. Rather, SCE retains the burden to show that its decision not to build, if any, is reasonable. Absent compelling reasons otherwise, we are unlikely to agree with SCE that the asymmetric treatment alone would justify SCE deciding not to build RPS resources.

We are pleased, however, that SCE also reports that it has begun development of new generation studies, as funded via its general rate case (GRC) decision, D.06-05-016. Regarding renewables, SCE states it began a study in the third quarter of 2006 and expects initial results by the second quarter of 2007. SCE concludes that, should SCE determine that there is a cost-effective renewable resource that it could propose to benefit its customers, SCE would likely "pursue the development of this resource assuming a successful resolution of the asymmetric risk issue." (Reply Comments, p. 16.) We encourage SCE to consider building RPS resources independently of how the issue is resolved. Moreover, SCE is encouraged, as are the other IOUs, to take into consideration the possibility of up to an extra 1% rate of return on such investment as additional incentive to help achieve the state's renewable resource goals.

4.3. Financial Disclosures, Rate Adjustments, and Change in Law

Four related issues arise relative to financial disclosures.

4.3.1. Disclosures Pursuant to FIN 46(R)

Each IOU's proposed RPS Plan requires access to seller's financial statements for possible consolidation.[11] SCE and SDG&E relate this to FIN 46(R).

CalWEA objects, arguing that developers consider much of the information proprietary. Further, CalWEA says it knows of no requirement that a utility consolidate its financials with that of a developer, and that SDG&E reports no consolidations to date.

SDG&E correctly responds, however, that the IOU has no choice in the matter to the extent consolidation turns out to be required pursuant to FIN 46(R). Therefore, it is reasonable to adopt a term that requires certain disclosures, when required.

If this term must be included, CalWEA says it does not object to a carefully tailored contract provision, but there should be no requirement that the developer agree to open its books to the utility as a condition of participating in the solicitation. We concur. We will not require disclosure as a condition of submitting a bid. In fact, PG&E proposes to clarify its solicitation to require disclosure as part of the contract negotiation process, not during the evaluation of bids. (PG&E Reply Comments, p. 6.) We adopt PG&E's clarification. That is,

[11] See PG&E 2007 Solicitation Protocol, Section XII.B, page 41. See SCE 2007 Proforma Agreement, Appendix 2C, Article 3.22, p. 40. See SDG&E 2007 Plan, Appendix A (Proposed RFO), Section 8.0, p. 20.

disclosure shall be required, if at all, no sooner than after the project is on an IOU's shortlist. We adopt this provision for all three IOUs.

Finally, regarding the specific language, CalWEA does not propose an alternative "carefully tailored contract provision" for our consideration.[12] Each IOU's proposed Plan, however, contains a provision that appears reasonable. That is, while the wording of each IOU Plan is different, each essentially states that if the IOU determines that consolidation is required, the seller must provide access to financial information.

Thus, we require the Plans to be amended so that disclosure is not required before creation of the shortlist, but otherwise adopt the language proposed by each IOU. If a dispute regarding FIN 46(R) arises after the contract is signed, parties may employ dispute resolution protocols generally contained in model contracts.[13]

4.3.2. Project-Specific Information

We note that IOUs require substantial project-specific information with bids.[14] We agree with CalWEA, however, that information at such level of detail

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[12] In arbitrations of telecommunication interconnection agreements, parties are required to present specific alternative proposed language. (See Resolution ALJ-181, Rule 3.6.) The procedural framework here is not that of arbitration, but parties increase the likelihood of making a compelling case when they provide specific proposals.

[13] PG&E Proposed PPA, Article 12. SCE Proposed Pro Forma Agreement, Article 12.

[14] For example, PG&E requires the bidder to include projections of revenues, expenses (disaggregated into many categories), interest payments, principal repayments, and capitalization (both debt and equity). (2007 Solicitation Protocol, Attachment E.) This permits PG&E to estimate the project's return on equity and rate of return. Similarly, SCE requires applicant to include a printout of the results from SCE's Revenue Calculator. (2007 Plan, Appendix 2E, Article 4.11.)

would normally be considered proprietary. While IOU's commit to keeping the information confidential, it is not entirely clear that IOUs need this much information to reasonably evaluate a project. If of limited usefulness or unneeded, perhaps the level of detail can be reduced, or the requirement eliminated.

For example, we note above that SCE is right when it says "neither party is able to predict what is going to happen during the term of these agreements." (SCE Reply Comments, page 2.) Projections are just that. An IOU has no inherently better ability to predict the future than a developer, a bank, the federal government, the California Energy Commission (CEC) or the Commission.

The IOU's interest in detailed project-specific financial information may go beyond an independent assessment of project viability. It may also be relevant in potentially negotiating a lower price on behalf of ratepayers, probably to be used during the "contract negotiation process" after the project is on the short list. In this context, this level of financial disclosure seemingly makes the IOU and its ratepayers more like a "partner" than a disinterested, competitive "buyer."

Nonetheless, the vitally important public health and safety aspects of safe and reliable electricity generation at every instant, and over the decades, require a close relationship between buyer and seller. Whether or not intentional, the financial health of both buyer and seller become important. This may require a substantial degree of project-specific financial information at the beginning of the relationship, and over time.

We also note above the role of credit and collateral in sharing risk between the IOU, developer and ratepayers. Risk sharing is an important element of the hybrid electricity market. We encourage IOUs and parties to continue to consider the issue and present creative ideas. We decline to direct IOUs to modify their Plans to require less project-specific financial information with the developer's bid. Nonetheless, we encourage IOUs and parties to rethink what exactly is needed, particularly in the context of sharing risk over the term of the agreement, and make proposals as appropriate for our consideration.

4.3.3. Rate Adjustments

SDG&E's 2007 proposed Plan notes that beyond the direct costs of the purchased power there are at least two other costs with RPS contracts. These are costs resulting from debt equivalence and FIN 46(R) requirements.[15] To the extent that individually executed PPAs will impact SDG&E's capital structure, SDG&E proposes that SDG&E be permitted to seek relief in its Commission advice letter filing for approval of each PPA. (SDG&E 2007 Proposed Plan, p. 20.)

SDG&E's proposal to seek relief by an advice letter is rejected. Advice letters are intended to be used primarily for compliance filings. A change in capital structure, or other cost recovery due to debt equivalence or FIN 46(R), is beyond a simple compliance filing. Nor does SDG&E propose a formula, for example, and none is litigated and resolved here, to account for these effects in a way that might be easily executed upon the filing of an advice letter.

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[15] According to SDG&E, long-term financial obligations, such as PPAs, are treated by credit rating agencies as additional debt. "As SDG&E executes more and more power purchase agreements, the cumulative debt equivalence of all these agreements may greatly affect SDG&E's credit profile and, consequently, its financial standing." (SDG&E 2007 Plan, p. 18.) Similarly, "FIN 46(R) will affect SDG&E's reported financial data and may have negative impact on SDG&E's balance sheet and/or credit profile." (*Id.*, p. 20.)

Moreover, TURN correctly argues that SDG&E's approach is inconsistent with past Commission orders. We ordered that "IOUs shall justify the debt equivalence factors for PPAs on a case-by-case basis in their cost of capital proceedings." (D.04-12-048, Ordering Paragraph 23.) We did this because debt equivalence might require the infusion of more equity in the capital structure, for example. This is best assessed in a cost of capital proceeding. This is also true for FIN 46(R), since a consolidated financial statement might affect an IOU's credit profile (e.g., increasing its risk) and resulting cost of equity. It is not a matter than can easily be handled by advice letter (at least unless and until one or more parties propose a streamlined, simplified method to do so). SDG&E does not convincingly show otherwise.[16]

SDG&E argues that TURN fails to account for the harm that will occur if the matter is deferred to cost of capital proceedings. SDG&E says that the ratemaking relief related to FIN 46(R) "must be addressed immediately." (Reply Comments, p. 10.) Moreover, SDG&E asserts:

> "prudent corporate planning dictates that SDG&E obtain certainty and clear direction at the time it signs contracts that may have negative impacts on creditworthiness regarding the ratemaking relief available to mitigate such impacts." (*Id.*)

We appreciate SDG&E presenting an issue that may need resolution, and doing so in a timely way, consistent with our expectations for IOUs to do so. (D.06-05-039, pp. 19-20.) SDG&E, however, presents insufficient support for its

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[16] It may be that this matter will eventually become routine and can be handled by a balancing account in a simple offset proceeding, or a formula applied with an advice letter. We do not, however, have data or experience to reach that conclusion here.

proposal, and its claim of urgency, to convince us at this time to adopt its proposed relief. Regarding urgency, for example, it is uncertain that any consolidation of financial statements will be required under FIN 46(R) at all. Even if required, the possible size of the effect is unknown (e.g., change in capital structure of no measurable effect, 0.1%, 1.0%, other). Nonetheless, when assessing RPS bids, SDG&E may rely on the fact that ratemaking relief, if any, is available via cost of capital or other applicable proceeding, but not at this time via advice letter.

4.3.4. Change in Law

SDG&E reports that the accounting industry is still considering the relevance of FIN 46(R) in the renewables context, and application of FIN 46(R) is being finalized. (SDG&E Reply Comments, pp. 8 and 10.) CalWEA notes that there may be ongoing changes in accounting rules. (CalWEA Comments, p. 3.)

More generally, at any time over the life of a contract there may be new or revised laws, regulations or rules which affect terms and conditions under the contract. Proposed model contracts would apparently contemplate parties handling such changes pursuant to dispute resolution procedures (including provisions for mediation and arbitration). It may be useful for IOUs to consider addressing such situations directly in model contracts.

For example, we encourage IOUs and parties to examine the change of law provisions in recently approved telecommunications interconnection agreements. One such example is included in Appendix C. The approach used in the telecommunications industry may assist parties in the electricity industry and, if so, IOUs and/or parties may make specific proposals for the next RPS proposed Plans (i.e., 2008 model contracts).

We clarify one point in this regard. Substantive changes to contracts must be brought to the Commission's attention. That is, "CPUC approval" requires that a contract contain a term subjecting the contract to continuing Commission review of the buyer's administration of the agreement. (D.04-06-014, Appendix A, page A-1.) It is extremely unlikely that the Commission would find a buyer's administration of the agreement to be reasonable if parties materially change the terms and conditions of the agreement but do not bring this to the attention of the Commission. Therefore, we make clear that the IOU must bring substantive changes in any RPS contract to the Commission's attention.

4.4. Waivers and Disclaimers

In conditionally approving the 2006 Plans, we noted that each IOU's Plan contained many disclaimers allowing it to reject offers or terminate solicitations. (D.06-05-039, p. 49.) We declined to limit these disclaimers, but reminded IOUs that they must reach the RPS goal of 20% by 2010 (with appropriate application of flexible compliance rules). We encouraged IOUs to rethink the tone and nature of their disclaimers.

In response, PG&E proposes to remove language that would require bidders to waive any state or federal constitutional right as a condition of participating in the solicitation. This is an improvement. Nonetheless, PG&E proposes retaining language that requires the bidder, with limited exception, to waive "any rights under statute, regulation or common law to assert any claim or complaint or other challenge in any regulatory, judicial or other forum…" (2007 Solicitation Protocol, Section VII, p. 42.) CalWEA asserts PG&E's waivers remain over-reaching and should be eliminated. CalWEA asserts neither SCE nor SDG&E propose such offensive requirements.

We again decline to eliminate such broad language. We remind PG&E, SCE and SDG&E that the latitude provided here may not be used as an excuse for failing to meet the RPS Program goals. We may deal with this again in a subsequent decision on various policy issues. Below, we deal more specifically with PG&E's proposed language regarding relief bidders may seek at the Commission.

4.5. Scheduling Coordinator

SCE proposes to perform SC services. (SCE Bid Solicitation Documents, Attachment 2C, 2007 Pro Forma Agreement, Section 3.11, pp. 32-33.) In response, CalWEA asserts all IOUs should serve as SCs.

We decline to order each IOU to do so. PG&E correctly states that each renewable facility operator is best suited to understand, communicate, and manage both its expected and actual operations. As such, the operator may elect to be its own SC, or may use a scheduling agent. Moreover, the CAISO has initiated the Participating Intermittent Resource Program (PIRP) to address concerns regarding SC responsibilities for intermittent resources, according to PG&E. We have no information persuading us that facilities are having undue burden performing this service themselves, finding SC services elsewhere, or participating in the PIRP. Thus, we are not convinced that each IOU should be ordered to offer SC services.

We accept SCE's proposal to perform SC duties with one modification. SCE's offer includes language that makes it mandatory: "At least thirty (30) days prior to Initial Synchronization, Seller shall take all actions … necessary to authorize … SCE as Seller's Scheduling Coordinator … throughout the Term of this Agreement." (*Id.*, Section 3.11(a)(i).) We welcome SCE's offer to provide SC services, but do not believe it should be mandatory. As PG&E contends, generators are typically in the best position to schedule their performance. If they choose to do so, this should be permitted. SCE should amend its Plan to make clear its SC services are optional, not mandatory.[17]

Lastly, SCE proposes that operators take the risk of incurring certain penalties related to operations outside an established bandwidth. CalWEA contends that this imposes the risk of deviations outside a narrow bandwidth back on developers. CalWEA argues that IOUs should manage deviations with respect to RPS resources, and delivery forecasts from RPS generators should be in good faith, but not binding.

We are not convinced. SCE correctly states that if the RPS generator provides accurate and timely information, no CAISO deviation charges are assessed. Only if forecasts are incorrect or untimely, or outside established bandwidths, is a charge made. This reasonably places the burden where it belongs, since the RPS operator is in the best position to forecast and manage its operations. Inaccurate forecasting and scheduling can lead to excessive burden on operators in real-time. SCE's proposal to charge for deviations outside an established bandwidth provides an appropriate incentive for the RPS facility to forecast and operate reasonably, while allowing SCE to offer a useful SC service without itself incurring all the risk for deviations.

4.6. Evaluation Criteria

We have required since the beginning of the program that each IOU Plan have a clear and concise statement of the evaluation criteria used in assessing

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[17] For example, Article One of SCE's Pro Forma Agreement contains items to be filled in by parties. An element might be added here to state whether or not SCE is the SC.

bids. The statement must contain all criteria, including the benefits of the RPS program identified by both the Legislature and the Commission. It must encourage bidders to address such benefits, if any. This permits a bidder to know how its bid will be assessed, helps a project focus its bid on the factors to be judged, and promotes a reasonably fair, transparent and open process. (See D.03-06-071, p. 37; D.04-07-029, p. 28, Finding of Fact (FOF) 27 and 28; D.06-05-039, pp. 50-53, Conclusion of Law 3.)

We found in reviewing the 2006 Plans that each IOU could do a better job. We directed that each IOU amend its Plan to do so. The results varied.

PG&E improved its 2006 Protocol, for example, expanding on its old Section XI.D by including a new Section XI.E. The new section more fully identified non-quantifiable factors and requested bidders to address the factors, if applicable.

SCE improved the "Evaluation of Proposals" section within its 2006 Procurement Protocol by including more items in its quantifiable attributes, plus more description of those attributes. We specifically directed SCE to make a particular decision reference clear, and SCE did so. Also, however, we said: "SCE must state each…qualitative criterion and solicit bidders to address such benefits, if any, within these criteria." (D.06-05-039, p. 51, footnote 19.) SCE failed to include all the qualitative factors from the referenced decision, and failed to solicit bidders to address such benefits, if any. SDG&E similarly made some improvements.

The language in each IOU's proposed 2007 Plan is still not adequately clear, comprehensive, explanatory, inclusive, and concise. For example, PG&E

proposes to eliminate Section XI.E. This leaves essentially no discussion of qualitative factors, and no solicitation of bidders to address these factors.[18] SCE's proposed language continues in its failure to address all qualitative factors and solicit bidders to address such benefits. IOUs can continue to improve these sections.

Each IOU was directed to submit a preliminary Evaluation Criteria and Selection Process Report on September 29, 2006.[19] A workshop on transparency of the RPS procurement process, including evaluation criteria, was held on December 15, 2006. The first reports from PG&E and SCE were filed on December 21, 2006 along with short lists.

Work continues in this area, and it continues to deserve this work. Each IOU can do a better job clearly explaining its evaluation criteria and selection process. Each must do so in its amended 2007 Plan.

Thus, as we also said last year, each IOU should amend its Plan to do a better job of clearly and specifically stating each factor used in its evaluation. These include factors found and declared important by the Legislature, and discussed in Commission decisions. Each Plan must specifically invite bidders to address such factors and related benefits, if any. We also encourage each IOU to again review the body of RPS decisions, beginning with D.03-06-071, to help it

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[18] The organization of PG&E's Protocol could be improved. Many, if not all, the factors are listed in the "Required Information." (2007 Solicitation Protocol, Section VIII.C.) They are not listed or cross-referenced in the section titled "Evaluation of Offers." (2007 Solicitation Protocol, Section XI.)

[19] These reports were ordered in D.06-05-039, pp. 44-45. The first report is due with each IOU's shortlist of bids.

prepare a clear and concise statement of the evaluation criteria used to assess bids, including all quantitative and qualitative factors, plus our direction to encourage bidders to address particular benefits, if any.

Finally, it seems unlikely that the evaluation criteria and selection processes at the three IOUs are so uniquely different that they merit three different approaches and descriptions. We encourage the three IOUs to meet and consider drafting one section that each may use in its Plan. This does not preclude each having, in part, some uniquely different language to reflect limited differences at each company. Nonetheless, we think one largely similar form, format and description may improve the overall approach to the subject. IOUs should work with Energy Division on the continuing development of this item.

4.7. Changes Pursuant to SB 107

Parties were asked to address changes that might be required in each IOU's draft 2007 Plan due to the passage of SB 107, effective January 1, 2007. In particular, parties were asked to address four items: (a) RECs, (b) agreement information, (c) access to bid information, and (d) other. PG&E also raises a concern relative to timing, which we address below.

4.7.1. RECs

We adopted a limited number of standard terms and conditions for RPS contracts in 2004. One such term involved the definition and ownership of RECs. (D.04-06-014, Appendix A, pp. A-2 to A-3.)

SB 107 now adopts a specific meaning for RECs. Moreover, SB 107 requires that contracts for the purchase of electricity generated by an eligible renewable energy resource include the REC associated with all generation under the contract. IOUs propose four changes to their draft Plans relative to RECs and their treatment under SB 107.

4.7.1.1. Add Definition of REC and Conveyance to IOU

First, each IOU proposes adding a definition of REC in the appropriate part of its model contract. The proposals vary, but each essentially refers to, or quotes, new § 399.12(g) from SB 107. There is no opposition to adding a definition of REC.

To promote consistency, we adopt PG&E's proposal for all three IOUs. PG&E's proposal is succinct, while also being robust in the face of potential change. We direct each IOU to use this definition[20] in the appropriate part of its model contract:

> " 'Renewable Energy Credit' has the meaning set forth in Public Utilities Code Section 399.12(g), as may be amended from time to time or as further defined or supplemented by Law."

SB 107 also requires that the contract include the RECs associated with the RPS energy. Little more is needed, however, since this provision is already required via D.04-06-014. That is, it is part of the non-modifiable term used for the definition and ownership of RECs (requiring that the seller convey all Environmental Attributes to the buyer). SCE proposes some additional language to ensure conformance with SB 107. SCE's proposal is adopted for SCE.

4.7.1.2. AB 32 Concepts

Second, PG&E proposes inclusion of some additional items in the list of pollutants, consistent with concepts embodied in Assembly Bill (AB) 32. There is no opposition. PG&E's proposal is adopted, as cited more fully below under Green Attributes.

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[20] SCE and SDG&E may also include PG&E's definition of "Law" as they determine necessary or appropriate.

4.7.1.3. Include REC in Environmental Attributes

Third, D.04-06-014 adopted the term "Environmental Attributes" to address the definition and ownership of RECs. PG&E and SDG&E now propose that this language be amended to refer to RECs. Their proposals differ slightly. We adopt PG&E's proposal as more encompassing. We direct that all three IOUs adopt the new term cited more fully below under Green Attributes.

4.7.1.4. Green Attributes

Finally regarding RECs, PG&E and SDG&E propose that the term "Environmental Attributes" be changed to "Green Attributes." In support, they assert that the Commission's definition of "Environmental Attributes" (capitalized in D.04-06-014 and in model contracts) includes RECs, but that SB 107, in establishing the statutory definition of RECs, provides that RECs include all "environmental attributes" (not capitalized). As a result, they point out that confusion is possible since Environmental Attributes in D.04-06-014 incorporate RECs, while environmental attributes pursuant to SB 107 are only one aspect of RECs. As a result, SDG&E and PG&E agree that the potential for confusion caused by the juxtaposition of these terms may, and should, be mitigated, and they propose modifying the Commission's term.

We agree. Our original term for the definition and ownership of RECs included the term "Green Tags." Thus, the proposal of PG&E and SDG&E to use "Green Attributes" is reasonably parallel to a term with which parties are already familiar without causing confusion. In adopting the original term, we said "we expect that the contract language will become more refined as the parties and the Commission gain further experience." (D.04-06-014, p. 6.) We think that is the case here.

Central California Power (CCP) argues against the change, saying SB 107 did not create any potential for confusion. We disagree. While the change from "Environmental Attributes" to "Green Attributes" is not strictly required, we agree with PG&E and SDG&E that the likelihood of confusion is easily avoided by adopting their proposed change. The change does not alter the original concept behind use of the term "Environmental Attributes," nor, contrary to CCP's concerns, does it create any conflict with SB 107.

Thus, we replace the non-modifiable term adopted in D.04-06-014 for "Environmental Attributes" with the non-modifiable term "Green Attributes." We similarly conform Section 3.4 of the standard term and condition for RECs (as recommended by GPI in comments on the proposed decision). (See D.04-06-014, Appendix A, pp. A-2 to A-3.)

We decline to add "any other tradable rights" as proposed by PG&E for a fifth item in the list of what is an environmental (green) attribute. The list is already characterized as "include[s] but not limited to." Nonetheless, it is unreasonable to add a term as undefined and open-ended as "any other tradable right," particularly since it may cause unintended disputes with regard to taking of property rights. We saw no need for language this broad in 2004, and similarly see no need today. Finally, we combine PG&E's proposed fourth term with the third term, as recommended by GPI.

As a result, the non-modifiable term will be as follows. To more easily identify the language changed from that adopted in D.04-06-014, the changes[21] are in bold:

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[21] We also adopt PG&E's proposal to change the statement that green tags are accumulated on a "kWh" basis to a "MWh" basis for internal consistency.

" '**Green** Attributes' means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the generation from the Project, and its displacement of conventional Energy generation. **Green** Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), **nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride** and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change, **or otherwise by law,** to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere; (3) the reporting rights to these avoided emissions such as Green Tag Reporting Rights and **Renewable Energy Credits**. Green Tag Reporting Rights are the right of a Green Tag Purchaser to report the ownership of accumulated Green Tags in compliance with federal or state law, if applicable, and to a federal or state agency or any other party at the Green Tag Purchaser's discretion, and include without limitation those Green Tag Reporting Rights accruing under Section 1605(b) of The Energy Policy Act of 1992 and any present or future federal, state, or local law, regulation or bill, and international or foreign emissions trading program. Green Tags are accumulated on a **MWh** basis and one Green Tag represents the **Green** Attributes associated with one (1) MWh of Energy. **Green** Attributes do not include (i) any energy, capacity, reliability or other power attributes from the Project, (ii) production tax credits associated with the construction or operation of the Project and other financial incentives in the form of credits, reductions, or allowances associated with the project that are applicable to a state or federal income taxation obligation, (iii) fuel-related subsidies or "tipping fees" that may be paid to Seller to accept certain fuels, or local subsidies received by the generator for the destruction of particular preexisting pollutants or the promotion of local environmental benefits, or (iv) emission reduction credits encumbered or used by the Project for compliance with local, state, or federal operating and/or air quality permits. If the Project is a biomass or landfill gas facility and Seller receives any tradable **Green** Attributes based on the greenhouse gas reduction benefits or other emission offsets

> attributed to its fuel usage, it shall provide Buyer with sufficient **Green** Attributes to ensure that there are zero net emissions associated with the production of electricity from the Project."
>
> "3.4 **Green** Attributes. Seller hereby provides and conveys all **Green** Attributes from the Unit(s) to Buyer as part of the Product being delivered, as such term is described in the applicable Transaction confirmation for the period set forth in such confirmation. Seller represents and warrants that Seller holds the rights to all **Green** Attributes from the Unit(s), and Seller agrees to convey and hereby conveys all such **Green** Attributes to Buyer as included in the delivery of the Product from the Unit(s)."

4.7.2. Agreement Information

The second general area dealing with possible updates due to SB 107 involves disclosure of certain project information. In particular, SB 107 requires:

> "The standard terms and conditions shall include the requirement that, no later than six months after the commission's approval of an electricity purchase agreement entered into pursuant to this article, the following information about the agreement shall be disclosed by the commission: party names, resource type, project location, and project capacity." (SB 107, § 399.14(a)(2)(D).)

SCE reports that its pro forma agreement already provides for release of this information. Thus, no modification is necessary.

PG&E and SDG&E each have contract language which permits release of the information consistent with requirements of SB 107. Each, however, also includes a sentence which in substance provides: "If Option B is checked on the Cover Sheet, neither Party shall disclose party name or project location, pursuant to this section, until six (6) months after such CPUC Approval."[22]

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[22] The Cover Sheet to each model contract includes options regarding confidentiality.

PG&E points out that this last sentence is not fully consistent with the SB 107 time period. PG&E proposes deleting the sentence, as well as updating the solicitation Cover Sheets to remove reference to Option B. We agree, and direct SDG&E to do the same.

Finally, SDG&E proposes that "online date and delivery point" be included in the list of disclosable terms for consistency with D.06-06-066. No party comments or objects. We adopt SDG&E's proposal. To the extent not already included, each IOU shall modify its list to also include online date and delivery point. It should also include "expected deliveries (energy)" and "length of contract," consistent with our recent decision regarding SB 1488. (D.06-06-066, Appendix 1, pp. 16-17, Items F and G.)

4.7.3. Access to Bid Information

The third general area dealing with possible updates due to SB 107 involves access to bid information. In particular, the original RPS legislation required that the Commission adopt a process for determining market prices. It required that the Commission make specific determinations of market prices after the closing date of a competitive solicitation. It also required that an electrical corporation not transmit or share the results of a competitive solicitation until the Commission had established market prices. (§ 399.14(a)(2)(A).) Effective January 1, 2007, the restriction on an electrical corporation transmitting or sharing the results before the Commission has established market prices is lifted. (SB 107, § 399.14(a)(2).) This may cause changes in the IOUs' Plans and Commission procedures.

Parties were asked to identify any necessary changes in their proposed 2007 Plans to conform to the lifting of this restriction. Each IOU reports that its proposed Plan is consistent with this provision in SB 107 and no changes are necessary.

Consistent with the original legislation, earlier Commission orders had adopted procedures whereby Commission staff would not see the results of the RPS solicitation until after the Commission had adopted the market price referent (MPR) resolution.[23] We lift this restriction effective January 1, 2007. For example, the schedule we adopt below no longer contains procedures limiting staff access to bid information before calculation of the MPR, and none shall be applied going forward. Moreover, effective January 1, 2007, we make clear that there shall be no limitation on an electrical corporation transmitting or sharing the results of any competitive solicitation for eligible renewable energy resources with the Commission.

4.7.4. Other

The last area involves parties identifying and addressing other aspects of SB 107 that might require changes in the proposed 2007 Plans (with two specific exceptions which we will address elsewhere: (a) flexible compliance in 2010 and beyond and (b) contracts of less than 10 years' duration). In response, PG&E recommends that the Commission expressly allow consideration of certain changes to non-modifiable standard terms and conditions through the advice letter process.

For example, PG&E argues that a change in a non-modifiable term should be permitted by advice letter if the developer requires such change and provides

[23] For example, see D.04-07-029, p. 10 ("PRG [Procurement Review Group] meetings, not including Commission staff, are held to review bid results") and Finding of Fact 7 on p. 41. Also see D.05-12-042, Appendix B, p. 1, and D.06-05-039, Appendix A, p. 1.

a declaration explaining why the change is necessary for project financing or to otherwise proceed. PG&E also points out that current non-modifiable terms may conflict with changes in California law and court orders over time. While the issue deserves consideration, we decline to address it now for the following reason.

On February 1, 2007, PG&E and SCE jointly filed a petition for modification of D.04-06-014. (D.04-06-014 adopted standard terms and conditions for RPS contracts, with some designated as “may be modified by parties” and others as “may not be modified.”) The petition, among other things, seeks clarification regarding how and when standard terms and conditions may be modified. We will address PG&E’s recommendation when we consider the joint petition for modification.

4.7.5. Timing

PG&E recommends that SB 107-related changes, if any, also be applied to contracts from prior solicitations that may come to the Commission for approval after January 1, 2007. We agree, as explained below. Parties should use the previously described terms as and where applicable (e.g., for RECs, agreement information, access to bid information) for contracts that result from prior solicitations (e.g., 2004, 2005, 2006) that are presented for our consideration after January 1, 2007, where appropriate.

In comments on the proposed decision, many parties disagreed with this approach. For example, SCE states that a contract signed by parties after January 1, 2007 should include the relevant language, but the Commission should not require parties to amend a contract signed before January 1, 2007. Caithness Corporation argues that the requirement should apply only to contracts submitted 60 to 90 days after the effective date of this order so that parties have reasonable notice and opportunity to incorporate these terms.

We clarify here that contracts executed between an IOU and RPS project before January 1, 2007 should include the terms described above, but only to the extent reasonable and applicable. We do not make this a requirement. We do not direct that parties renegotiate an agreement that has already been executed. Rather, we leave that up to the judgment of the parties. On the other hand, an RPS contract executed between an IOU and a counterparty on or after the date this order is mailed should incorporate the terms described above.

4.8. Commission Review Process

The issue of considering changes to non-modifiable contract terms by advice letter raises the more general issue of how we process and consider RPS contracts. Our recent experience with advice letters, and the issues that have surfaced here, demonstrate a need to rethink our process.[24]

4.8.1. General Review of Contracts

With some exceptions, advice letters are typically used for compliance filings.[25] They should tend to be ministerial and reasonably straightforward. They should typically not raise complex or serious factual, legal, policy or technical issues. On the other hand, applications or other formal pleadings are the vehicle for discretionary and all other matters.

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[24] Section 4.8 in this decision (except for Section 4.8.3) is focused on process, not the evaluation criteria to be used when we consider any particular RPS contract.

[25] Our use of advice letters continues to evolve. We recently adopted a three tier system for consideration of many advice letters. (D.07-01-024, adopted January 25, 2007.)

We initially adopted an advice letter approach for consideration of IOU proposed RPS contracts. (D.03-06-071, p. 39.) This approach is in the context of the Commission having reviewed and accepted an IOU's RPS Procurement Plan. (§ 399.14.) The accepted Plan would contain standard terms and conditions adopted by the Commission, including performance requirements. (§ 399.14.) The Plan would contain one or more model contracts for use by parties in the solicitation. The proposed contracts would be submitted to the Commission for review after an IOU's competitive solicitation, least cost-best fit screening, and review by the Procurement Review Group. The Commission would review the results of a solicitation after this reasonably thorough process and "accept or reject proposed contracts…based on consistency with the approved renewable energy procurement plan." (Old § 399.14(c); new § 399.14(d), effective January 1, 2007.)

The adopted advice letter process contemplates a fundamentally compliance, relatively straightforward, reasonably ministerial filing. This process may or may not be feasible for contracts that do not fit these facts.

4.8.2. Continue with Current Process

To address this, the proposed decision would have had us adopt a procedural approach that differentiates the filing of RPS contracts into those to be considered by advice letter (i.e., for a "compliance" filing pursuant to a competitive bid solicitation using a model contract) or application (i.e., for filing of a contract reached outside a competitive bid solicitation and/or containing nonstandard terms and conditions that are substantively different that those in the model contract). There may be merit in using this structure to streamline and focus the efforts of parties and the Commission. If properly implemented it could facilitate reaching RPS program goals and targets sooner with less cost, plus greater efficiency and equity. Nonetheless, we decline to adopt this approach here.

While there may be benefits, there might also be costs. The application process, for example, may in some cases take more time (with potentially increased risk and cost for projects subject to delay). Nearly all, if not all, comments oppose adoption of the procedural approach framed in the proposed decision.

As a result, we maintain the status quo for now. RPS contracts may continue, consistent with existing Commission orders, to be submitted for Commission consideration by advice letter. We believe this will enable timely consideration of most, if not all, contracts.

Also consistent with existing Commission practice, Energy Division is the Commission's "gatekeeper" to screen and separate out contracts that require special attention. For example, under certain conditions Energy Division should reject an advice letter (with instructions that the applicant submit the item as an application if it wishes further consideration). Alternatively, Energy Division may seek Commission conversion on its own motion of an advice letter to an application.

The conditions under which this might be done include, but are not necessarily limited to, when: (a) an advice letter raises a potentially disputed, important, or significant issue of fact, policy or law (based on a filed protest or as identified by Energy Division); (b) the contract price exceeds the relevant MPR by a nontrivial amount; or (c) changes to modifiable or non-modifiable standard terms and conditions raise an important issue (based on a protest or as identified by Energy Division). An applicant might on its own elect to submit certain matters for Commission review and consideration by application rather than advice letter, but is not required to do so. Rather, applicants may continue to submit proposed contracts for Commission consideration by advice letter. Energy Division has the experience and responsibility, however, to continue to employ its administrative expertise to treat filed advice letters as advice letters when appropriate, but reject or convert others, as necessary and where reasonable.

4.8.3. Defense of Noncompliance Penalty

This discussion is generally with regard to process, not substantive review of submitted items. Thus, we do not repeat here what is said elsewhere in this order, nor what is said in prior orders, regarding contract review and possible penalties. We encourage parties to review this and prior orders.

Nonetheless, we address several factors above which deal with elements an entity should be able to show in any future defense relative to a non-compliance penalty, if any (e.g., reasonable credit and deposit policies and amounts, reasonableness of waiver and disclaimer language). We also note a few below (e.g., reasonableness of an entity's margin of safety in its procurement plan; SCE's failure to include high, base and low scenarios). In the interest of clarity, we point out that the comments here compliment and supplement, and do not replace or supersede, prior orders (e.g., D.06-05-039, Conclusion of Law 7, Ordering Paragraph 7.) We encourage each entity to review this and prior orders to ensure it is reasonably implementing the RPS program given the Commission's guidance.

4.9. Other Changes to Model Contracts

The proposed decision employed an approach wherein the accepted RPS Plan included a complete model contract, which in turn incorporated all standard terms and conditions from D.04-06-014. This would be the model contract. It would facilitate and enable expedited Commission consideration of subsequent conforming agreements. Consistent with this approach, the proposed decision would have had us direct SCE to amend its proposed Proforma Agreement to be consistent with all Commission adopted standard terms and conditions (both modifiable and non-modifiable) from D.04-06-014. It would then have recognized that SCE and the bidder could modify the terms permitted to be modified.

In its comments on the proposed decision, SCE argues that it should not be required to modify its Proforma Agreement. SCE says its couterparties have found some Commission non-modifiable terms (e.g., "assignment") to be unacceptable. SCE also says some standard terms do not work in the context of SCE's entire 2007 Proforma Agreement (e.g., definition of "as-available" is a remnant of the Edison Electric Institute agreement that no longer makes sense, according to SCE). SCE asserts that it would need to publicly state it would be unable to enter into its own Proforma Agreement if SCE is required to modify its Proforma Agreement to comply with the exact terms in D.04-06-014. SCE contends this would be a waste of time and resources.

It has now become apparent (through recent advice letters, applications, the petition for modification of D.04-06-014, and comments on the proposed decision by parties other than SCE) that not only SCE but also other IOUs have changed standard terms and conditions over time (both modifiable and non-modifiable). We believe this subject deserves additional consideration. SCE and others argue that continuity of the RPS Program (so that California has a reasonable opportunity to reach RPS goals) is too important to delay the 2007 solicitation. We essentially agree.

Therefore, we accept the RPS Plans proposed by the IOUs for the 2007 solicitation without requiring that they conform to the precise standard terms and conditions adopted in D.04-06-014. In doing so, we withhold judgment on parts of the Plans not addressed herein. We also reserve judgment on treatment of modifications to standard terms and conditions for our later consideration of the petition for modification of D.04-06-014. As stated above, Energy Division may at its discretion require contracts with changes to the standard terms and conditions otherwise adopted in D.04-06-014 to be filed by application.

Thus, IOUs are permitted to use their proposed Plans for their 2007 solicitation, subject to the modifications otherwise ordered herein, as summarized in Appendix A. At the same time as we have also said in other contexts, IOUs have the responsibility, within flexible compliance rules, to reasonably administer and implement the program and to meet RPS targets. This responsibility is not altered by our decision to permit IOUs to proceed on this basis with the 2007 solicitation.

4.10. RPS Data

The August 21, 2006 Scoping Memo directed each IOU to submit APT, IPT and other RPS data. In October 2006, we issued our Reporting Decision, D.06-10-050.

We here conditionally accept each IOU's 2007 Plan, subject to it being amended and refiled within 15 days. IOUs may update their Plans, as appropriate, to reflect reporting decisions in D.06-10-050. This should simplify each filing, and IOUs may make or decline to make those simplifications at this time.

5. Issues Specific to an IOU Plan

We comment further below on issues specific to each Plan. As we have said before, however, conditional acceptance of these Plans does not constitute endorsement or adoption of proposed policy measures that have not yet been fully vetted. It also does not reflect endorsement or adoption of each aspect of each plan. Rather, we conditionally accept each Plan, subject to limited required amendments and several suggestions made herein. Each utility remains ultimately responsible for proposing and executing reasonable Plans that achieve RPS targets, including 20% by 2010, subject to flexible compliance rules. We will later judge the extent of each IOU's success, including the degree to which each IOU implements Commission orders, applies the Commission guidance, demonstrates creativity and vigor in program execution, and reaches program targets and requirements.[26]

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[26] The judgment may include whether or not to apply certain penalties. It may also include whether or not modify implementation of the program. One such modification may be to apply more non-modifiable standard terms and conditions. (§ 399.14.) This modification and other changes will be considered later, as needed, with the benefit of CEC recommendations from its 2006 Integrated Energy Policy Report Update (adopted January 3, 2007; Publication # CEC-100-2006-001-CTF). The CEC Report recommends further study of several potential structural changes in the RPS Program. One such change might be to employ a renewables "feed-in" tariff. (Id., p. 60.) One type of feed-in tariff is payment of a fixed price set at the market price referent for all electricity sold to the buyer. This may be somewhat like the structure previously used for qualifying facilities (QFs). The QF structure involved standard offers at fixed prices with limited room for negotiation. In contrast, the RPS structure now involves limited standard terms and conditions with much greater room for negotiation and vigorous price competition. We welcome creative and vigorous efforts by IOUs to make the current structure succeed in order to obviate the need to consider further structural changes. Moreover, we repeat from our prior orders that it is our "our clear desire never to visit these penalties." (D.03-06-071, p. 52; D.06-05-039, p. 29.) Nonetheless, we will consider penalties and changes if and as needed.

5.1. PG&E

PG&E's proposed Plan does not reflect current conditions in some respects, or is perhaps unclear, and should be updated as appropriate. Six examples follow.

a. PG&E's proposed Plan states that each IOU must increase its procurement "so that 20% of its retail sales are supplied by ERRs by 2017. As a matter of policy, the CPUC has accelerated the deadline to 2010." (2007 Solicitation Protocol, Section I.A., p. 1.) This is now a requirement of law. (SB 107, § 399.15(b)(1), effective January 1, 2007.)

b. PG&E requires a bidder to provide a project description that includes several factors recognized by the Legislature and Commission. (2007 Solicitation Protocol, Section VIII.C., Tab 5, Items i, j, k and l.) PG&E should consider also including factors stated as important by the Governor, such as biomass. (See Executive Order S-06-06.)

c. PG&E refers to certain transmission ranking costs as part of a report prepared and filed pursuant to a ruling dated November 9, 2005 in OIR 04-04-026. (2007 Solicitation Protocol, Section X.B.1.ii.) The transmission ranking costs for the 2007 Protocol will be pursuant to a ruling dated August 21, 2006 in R.06-05-027. (The assigned Commissioner has recently issued a ruling adopting certain transmission ranking costs; PG&E may wish to refer to that ruling.)

d. PG&E refers to R.04-04-026 as a proceeding in which certain things may happen. (2007 Solicitation Protocol, Section XVII.) R.04-04-026 is closed for any purpose suggested here by PG&E. (It is open at the moment only for consideration of intervenor compensation requests.)

e. PG&E refers to Section V.C but may mean Section V.D. (2007 Solicitation Protocol, Section XIX.G.)

f. PG&E refers to the 2006 Solicitation, June 30, 2006 and/or July 10, 2006 in several places, where the correct references are to the 2007 Solicitation, a document dated in early 2007 and/or a form returned in mid-2007. (2007 Solicitation Protocol, Attachment A, Solicitation Protocol Agreement, paragraph 1 and Confidentiality Agreement, paragraph 2; Attachment B, Form of Letter of Credit, item 2A; Attachment C, Notice of Intent to Bid, paragraph 2.)

PG&E's proposed Plan limits a bidder seeking relief regarding an alleged harm resulting from the solicitation to seeking that relief from the Commission. Specifically, PG&E says the only forums to challenge the conduct or the results of the solicitation are R.04-04-026 or the Commission's Alternative Dispute Resolution procedures pursuant to Resolution ALJ-185. R.04-04-026 closed for such purpose. Even if open, it is unclear whether either that proceeding or its successor (R.06-05-027) provide such forum. Moreover, the limitation may be understood to preclude a bidder from discussing concerns or potential problems with Energy Division or the Independent Evaluator. Such restriction should not be applied. PG&E should consider editing is limitation and its description accordingly.

5.2. SCE

SCE's proposed Plan, similar to PG&E's, does not reflect current conditions in some respects, or seemingly is incomplete, and should be updated as appropriate. Two examples follow.

a. SCE's proposed Plan contains a blank footnote. (2007 RPS Bid Solicitation Documents, Appendix 2A, p. 15.) The footnote should be entered or deleted with the final Plan.

b. SCE's proposed Plan states that certain attributes identified in D.04-07-029 will be utilized "as qualitative methods for evaluating tie-breakers." (2007 RPS Bid Solicitation Documents,

> Appendix 2A, p. 17, item 5.02.) SCE should state those attributes and explain how they will be used as tie-breakers.

In conditionally approving the 2006 Plans, we favorably noted some SCE-proposed contract language regarding equal treatment, fair dealing and good faith performance. (D.06-05-039, p. 48.) We encouraged each IOU to include such language in its Plan. SCE's proposed 2007 Procurement Protocol (Appendix 2A) appears not to do so. We again encourage SCE to include such language, not only in its proposed proforma agreement, but also in its Protocol.

SCE appears to apply integration costs as a specific cost adder. (SCE Report on RPS Evaluation Criteria and Selection Process dated September 29, 2006, Section III.D., pp. 5-6.) To the extent SCE applies a positive result, this is inconsistent with Commission direction to apply a zero adder. (D.04-07-029.) SCE should correct treatment of integration costs, as needed.

In its 2006 Plan, SCE projected RPS procurement needs based on an assessment of several variables, and developed three procurement need scenarios: high, base and low. SCE reported that it planned to procure to the high needs scenario in order to maximize its compliance prospects, even if that might result in an overstatement of its required procurement. (December 22, 2005 Plan, pp. 3-4.) The Commission commented favorably about SCE's contingency planning, and, as a result in combination with other factors, declined to order an IPT greater than 1%. (D.06-05-039, p. 21.) The Commission concluded, however, that each IOU must continue to include its own procurement margin of safety. (Id., Conclusion of Law 3(b)(1), p. 81.)

In contrast, SCE's 2007 proposed Plan fails to address a range of scenarios, and does not state a commitment to procure to a high needs level. For example, unlike Figure 1 in its 2006 proposed Plan, SCE's Attachment 1 to its 2007 proposed Plan does not include high, base and low cases. At the same time, SCE states that "SCE's bundled customer sales growth rate continues to exceed projections." (Proposed Plan, p. 14.) SCE is encouraged to reconsider the use of a range of scenarios when it prepares and submits its final Plan. Further, SCE should consider again committing, as it did in its 2006 Plan, to procure to the high needs case. To the extent SCE (and/or another IOU) fails to reasonably consider a procurement margin of safety in its amended 2007 Plan or proposed 2008 Plan, we will reconsider, to the extent necessary, an IPT of 1.2% or other margin of safety. (D.06-05-039, pp. 21-24.)

At the same time, we commend SCE when SCE says in its 2007 proposed Plan that its "overall goal is to achieve 20% renewables as soon as possible…" (SCE Proposed Plan, p. 2.) We think contingency planning facilitates achieving that goal. We do not seek to revisit the subject of contingency planning with the 2008 Plans. As we have said many times, however, we will hold each IOU, including SCE, to reaching RPS targets, including 20% by 2010 (subject to flexible compliance rules). We encourage each IOU, including SCE, to continue to include contingencies in its RPS Plans, and to plan accordingly.[27]

Finally, SCE should consider better ways to organize the many documents in its 2007 RPS Bid Solicitation Documents, Appendix 2. Separation by colored paper (as does PG&E) or separation by tabs (as does SDG&E) would improve the user's ability to understand the organization of the documents.

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[27] For example, PG&E's Protocol states that PG&E seeks to procure between 1-2% of its retail sales volume, or between 700 and 1,400 gWhs per year. (Protocol, p. 5.)

5.3. SDG&E

SDG&E's proposed Plan does not reflect current conditions in some respects, or seemingly is unclear or incomplete. It should be completed or updated when submitted as the final Plan, as appropriate. Four examples follow.

a. SDG&E's final Plan should employ careful explanation and use of acronyms (e.g., Procurement Plan, p. 21, "EPC").

b. If specific proceedings are identified, SDG&E should ensure the list is complete and up-to-date (e.g., SDG&E should consider referencing R.06-05-027 at Procurement Plan, Appendix A, Proposed RFO, p. 14).

c. If specific laws and decisions are referenced, with web links, the list should be complete and up-to-date (e.g., SDG&E should consider adding SB 107, plus all other relevant Commission decisions at Procurement Plan, Appendix A, Proposed RFO, p. 14.)

d. Many documents are contained in one Appendix. (Procurement Plan, Appendix B, Form PPA.) Further organization (e.g., index) and/or tabbing would be helpful. Moreover, it appears to reference changes to the Edison Electric Institute (EEI) contract, but the EEI contract is not included (e.g., Cover Sheet, p. 13 references Section 10.6, but that Section is not elsewhere apparent).

In its comments on the proposed decision, TURN raises an issue regarding the congestion cost calculation used by SDG&E in its least cost-best fit evaluation process. TURN says it learned of certain specifics regarding this issue only in January 2007, but that the effect on bidders may be great. TURN asks that the Commission either direct SDG&E to eliminate its congestion cost methodology in this cycle, or provide additional documentation as to the reasonableness of its approach.

In response, SDG&E asserts the Preliminary Report of the Independent Evaluator shows that the congestion cost methodology does not alter the short-list ranking of projects or otherwise skew the results. SDG&E claims TURN's concern does not provide adequate basis for elimination of the congestion cost methodology for the 2007 RPS cycle, but that SDG&E will engage TURN in further discussion on this issue.

We decline to direct SDG&E to eliminate its congestion cost methodology based on limited and late information. We support SDG&E discussing this further with TURN. We also expect SDG&E to explain this matter to Energy Division staff and the PRG, as appropriate. We expect parties to bring the matter back to our attention if, and as, necessary.

6. Schedule and Organization for 2007 Solicitation and 2008 Plans

6.1. 2007 Solicitation

In an upcoming decision on policy issues identified in the August 21, 2006 Scoping Memo, we may or may not change the solicitation cycle. Unless and until we do, we continue in our efforts to move toward a calendar year cycle. As such, we adopt basically the same components, and some of the same timeframes, in the RPS Solicitation Timeline for the 2007 solicitation that we employed for prior solicitations. (See D.04.07-029; D.05-12-042, Appendix B; D.06-05-039, Appendix A; this order, Appendix B.) We encourage parties to follow the schedule in Appendix B.

We include less specific components and fix less dates in the adopted schedule, however, to both acknowledge the request of IOUs for more flexibility, and the flexibility needed for staff and the Commission to complete its work. We also allow more time for contract negotiation, plus preparation and filing of advice letters, than provided in previous decisions. We here set end of year 2007 for contracts to be filed for Commission consideration.[28] We do this based on the nearly unanimous recommendation of parties in comments on the proposed decision, and our experience with previous requests for schedule extension.

Unlike the 2006 Solicitation, we decline to provide the option of an additional 45 days after Commission adoption of a resolution approving a contract to count such contract toward the 2007 solicitation. (D.06-05-039, Ordering Paragraph 6.) Our goal is to make solicitations no less often than annual. We are not convinced that extra time is needed to complete the 2007 solicitation.

As we have done before, we authorize the Energy Division Director, in administering the program, to modify the dates on Energy Division's own initiative, as necessary. Any modifications, however, should be consistent to the extent possible with our goal of bringing the 2007 solicitation to conclusion by the end of 2007. By bringing to conclusion we mean that contracts from the 2007 solicitation are filed with the Commission for Commission consideration. If a party desires schedule modification, the party may seek an extension by letter or electronic mail to the Executive Director, with a copy served on the service list, the Chief Administrative Law Judge, and the Energy Division Director. (See

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[28] We allowed 63 days between close of bidding and submission of advice letters in the 2006 solicitation. (D.06-05-039, Appendix A, page 3, day 103 to day 166.) We here allow 206 days for the same interval. This is an extension from the recommendation of PG&E in its comments on the proposed decision to use December 21, 2007 for the deadline, and a reduction from the recommendation of SCE and others to use a date in 2008.

Rule 16.6.) The Executive Director should consider such requests, if any, also in the context of our goal of completing this solicitation by the end of year 2007.

Our goal here includes making the process somewhat more streamlined and clear. Accordingly, the deliveries from all contracts from the 2007 solicitation filed for Commission consideration by the end of 2007 are eligible to be counted, if approved and otherwise consistent with flexible compliance rules, toward 2007 RPS Program goals. Deliveries from contracts derived from the 2007 solicitation but filed for Commission review after December 31, 2007 may count toward the RPS Program goals of the year in which they receive Commission approval (unless provided otherwise in the resolution or decision).

6.2. 2008 Plan

6.2.1. Schedule and Cycle

We adopt the same basic approach used in developing and reviewing the 2006 and 2007 Plans for the 2008 cycle. (D.05-07-039, p. 29; D.06-05-039, p. 58.) That is, we expect the filing and service of 2008 draft RPS plans and draft RFOs later this year (e.g., by August 15 so they potentially may be accepted at one of our meetings in December 2007). The specific schedule will be set by the assigned Commissioner or Administrative Law Judge (ALJ).

Moreover, as we have also done before, we authorize the Assigned Commissioner to assess the adequacy of Transmission Ranking Cost Reports (TRCRs) used in the LCBF ranking of bids. (D.04-06-013, D.05-07-040, D.06-05-039.) The assigned Commissioner or ALJ should set dates, as needed, for utilities to request information for the TRCRs, to file draft TRCRs, and 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. (D.05-07-040, Ordering Paragraph 7; D.06-05-039, Ordering Paragraph 7.)

6.2.2. Plan Organization and Ease of Use

Each IOU was directed to submit each 2007 Plan "in the form and format which the LSE [load serving entity] seeks to be adopted by the Commission." (August 21, 2006, Scoping Memo, Attachment C, p. 1.) Moreover, IOUs were "encouraged to use the same form and format." (*Id.*)

Above, we have reviewed each of the 2007 Plans as submitted for our consideration. Each Plan is a complex document that is not easy to assess and use. Each Plan is quite different in structure than the other Plans. We note that improvements have been made in the Plans over the previous cycles, but each remains relatively complex. We are not certain they need to be.

We encourage each IOU to continue to seek ways to improve its RPS Plan. We encourage IOUs as a group to use a common form and format. There does not appear to be anything so particularly unique about the plan to buy, or the contract to buy, electricity from a third-party RPS generator that each IOU must have its own form and format (even if some of the details in a Plan, or some particular contact clauses, might be different).

Consistent with the direction above, each 2008 proposed Plan must be in a form and format which the LSE seeks to be adopted by the Commission. It must be complete and current. Moreover, we encourage IOUs to seek ways to organize, format and present each Plan in a manner that facilitates its use by all involved, including bidders and the Commission.

Finally, we encourage IOUs and parties to give serious consideration to further development of improved model contracts, including standard terms and conditions. Better and more uniform model contracts will likely to be useable by more bidders without requiring substantial further negotiation and modification. This will permit a more streamlined process for bidding, negotiation and Commission review. The additional time spent "up front" could potentially be small compared to the time savings for the entire remainder of the process. Further, by reducing transaction time plus transaction and other costs, it might make the overall RPS structure more transparent, efficient and competitive. This could offer an opportunity to assist LSEs and California achieve the overall RPS goals sooner at lower cost.

7. Comments on Proposed Decision

The proposed decision of ALJ Mattson in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and Rule 14.2(a) of the Commission's Rules of Practice and Procedure. Comments were filed on February 1, 2007 by PG&E, SCE, SDG&E, CalWEA, Caithness, Union of Concerned Scientists (UCS), The Utility Reform Network (TURN), and the Green Power Institute (GPI). Reply comments were filed on February 6, 2007 by PG&E, SCE, SDG&E, TURN and GPI.

We make several changes to the proposed decision based on comments and replies. These include modifying the schedule; declining to adopt the proposed administrative structure, but retain our existing advice letter process for review of RPS contracts; clarifying that currently executed contracts need not be renegotiated for SB 107 provisions, but contracts submitted after the date this order is mailed should include SB 107 provisions where and as relevant; declining to direct SCE to modify its Pro Forma Agreement to include all standard terms and conditions from D.04-06-014; deferring consideration of modification to standard terms and conditions to the petition for modification of

D.04-06-014; and improving the adopted language for Green Attributes and RECs for increased consistency with D.04-06-014.

8. Assignment of Proceeding

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

Findings of Fact

1. Parties generally do not recommend extensive changes in proposed Plans, and no motion for hearing was filed.
2. PG&E proposes to reduce a portion of its Project Development Security for as-available, baseload and peaking (but not dispatchable) products, and no party opposes PG&E's proposal.
3. PG&E's proposed Delivery Term Security is 5% of the total revenues of the project, and no evidence demonstrates that this results in PG&E being "over-insured" at ratepayers' expense, nor that operating collateral of 5% is excessive.
4. PG&E includes an item in its proposed 2007 RPS Protocol for solicitation of "sites for development," wherein PG&E seeks offers for new or existing sites to be acquired by PG&E for the development, construction, and operation of an ERR.
5. Each IOU's proposed 2007 Plan showing relative to its consideration of whether or not to build its own resources is relatively limited, without many specifics, and, in SCE's case, also expresses concern with Commission policy.
6. To the extent consolidation of financial reports is required pursuant to FIN 46(R), the IOU has no choice, and certain financial information must be provided by the seller, but need not necessarily be required as part of the bid.
7. IOU-proposed Plans require a substantial amount of project-specific financial information with a bid.

8. Advice letters are intended to be used primarily for compliance filings, but a change in capital structure, or other cost recovery due to debt equivalence or FIN 46(R), is beyond the normal scope of a compliance filing.

9. There is no compelling evidence that RPS facilities are having undue burden performing SC services themselves, finding SC services from others, or participating in the PIRP.

10. SCE proposes to offer SC services, with the operator taking risk related to operations outside of an established bandwidth.

11. SCE's proposal to charge for deviations outside an established bandwidth provides an incentive for the RPS facility to forecast and operate reasonably, while allowing SCE to offer a useful SC service without itself incurring unreasonable risk for operational deviations.

12. Each IOU improved its statement of evaluation criteria and selection process for its amended 2006 Plan, but, consistent with direction in D.06-05-039 and discussion herein, each can further improve the statement included in its 2007 Plan.

13. Regarding changes relative to SB 107, each IOU proposes adding a definition of REC; PG&E and SDG&E propose changing "Environmental Attributes" to "Green Attributes"; and PG&E proposes including other changes to incorporate AB 32 concepts and RECs.

14. The term "Environmental Attributes" (defined in D.04-06-014) incorporates RECs, while "environmental attributes" (used in SB 107) are only one aspect of RECs and, as a result, SDG&E and PG&E propose mitigating the potential confusion by the Commission changing its term to "Green Attributes."

15. "Green Attributes" is reasonably parallel to, but unlikely to cause confusion with, a term parties already recognize ("green tags").

16. PG&E and SDG&E each initially proposed a sentence (regarding release of certain project information not fully consistent with the SB 107 time period of "no later than six months"), and PG&E now proposes deleting the sentence, as well as updating the solicitation cover sheets.

17. SDG&E proposes that the terms "online date" and "delivery point" be included in the list of disclosable terms related to project information, for consistency with D.06-06-066, and no party objects.

18. PG&E recommends that the Commission expressly allow consideration of changes to non-modifiable standard terms and conditions through the advice letter process, and this issue is also presented in a petition for modification of D.04-06-014 filed on February 1, 2007.

19. PG&E proposes that contracts resulting from prior solicitations and submitted for consideration on or after January 1, 2007 also contain relevant provisions pursuant to SB 107, while (in comments on the proposed decision) others oppose this requirement.

20. Each IOU's Plan has some actual or potential infirmities (e.g., not reflecting current conditions in some respects; limiting the ways in which a bidder may seek relief from the outcome of the solicitation process; not containing high, base and low case scenarios; poor organization; not including all documents to which it refers; not containing a dispute resolution procedure).

21. A solicitation cycle completed by the end of 2007 is consistent with the existing goal of completing each solicitation within one year.

22. Improvements have been made in the form and format of RPS Plans over the previous cycles, but each remains relatively complex, and additional improvements are feasible and desirable.

Conclusions of Law

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

2. PG&E, SCE and SDG&E should continue to have reasonable flexibility in the way each satisfies RPS program requirements, subject to Commission guidance, limited specific requirements, and a specific timeframe for limited dates in the next solicitation cycle.

3. Conditional approval of each 2007 RPS Plan (including Protocol, RFO, and model contracts) does not constitute endorsement or adoption of each element of each Plan; rather, each IOU 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 goals, targets and requirements).

4. The proposed 2007 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.

5. PG&E, SCE and SDG&E should each submit an amended Plan to the Energy Division Director, with service on the service list, within 15 days of the date this order is mailed and, unless suspended by the Energy Division Director within 22 days of the date this order is mailed, each utility should use its amended Plan for its 2007 RPS program and solicitation.

6. To the extent IOUs have reasonable flexibility in program administration (e.g., setting credit and collateral policies and amounts, disclaimer and waiver

language) an IOU later requesting deferral or waiver of a penalty should have the burden to present a showing in support of that request which, among other things, demonstrates reasonable administration within Commission guidelines.

7. Commission enforcement of each APT, and 20% by 2010, should take into account whether or not each electrical corporation undertook all reasonable actions to comply, including but not limited to, whether or not it reasonably considered building its own RPS resources.

8. Disclosure of detailed financial information should not be a condition for a developer to submit a bid but, if required at all, may be reasonably requested as part of the contract negotiation once the project is on the IOU's short list.

9. SDG&E's proposal to seek relief via advice letter for certain financing costs (i.e., FIN 46(R), debt equivalence) should be rejected.

10. IOUs and parties should consider including a "change in law" clause in model RPS contracts.

11. An IOU should bring substantive changes in any RPS contract to the Commission's attention.

12. SCE's proposal to offer SC services (with the facility's operator taking the risk of operations outside an established bandwidth) should be accepted, but the operator's taking of the offer should be optional.

13. Each Plan should continue to be improved, including better description of the evaluation criteria and selection process

14. Each Plan should include a definition of RECs as proposed by PG&E, SCE's additional language for conformance with SB 107 should be included for SCE's Plan, and "Environmental Attribute" should be changed to "Green Attribute" with most of the further changes recommended by PG&E.

15. PG&E and SDG&E should each delete a particular proposed sentence (regarding the period in which certain project information may be released that is inconsistent with the "no more than six months" required by SB 107) and change their cover sheets accordingly; PG&E, SCE and SDG&E should each include "online date," "delivery point," "expected deliveries (energy)," and "length of contract" in the list of disclosable terms consistent with D.06-06-066.

16. Effective January 1, 2007, neither an IOU's Plan nor Commission document should limit an electrical corporation transmitting or sharing the results of any competitive solicitation for eligible renewable energy resources with the Commission.

17. Parties should, as appropriate, use the terms described herein (e.g., for RECs, agreement information, access to bid information) for contracts that result from prior solicitations (e.g., 2004, 2005, 2006) presented for our consideration after January 1, 2007, but parties should not be required to engage in renegotiation of executed contracts.

18. Modification of the 2007 RPS Plans so that they conform with the precise standard terms and conditions in D.04-06-014 should not be required now, but the issue of when and how standard terms and conditions may be changed over time should be addressed in the petition for modification of D.04-06-014 filed on February 1, 2007.

19. IOUs may update their Plans, as appropriate, to reflect reporting components decided in D.06-10-050.

20. Individual IOU Plans should be modified to reflect current conditions and other items as noted in this order (e.g., inclusion of high, base, low scenarios; better organization; EEI and other documents).

21. The same basic components in the RPS Solicitation Timeline used for the 2006 Solicitation should be used for the 2007 Solicitation, with some adjustment in the schedule.

22. The Energy Division Director, in administering the program, may modify the Solicitation Schedule dates on Energy Division's own initiative, as necessary, but any modifications should be consistent, to the extent possible, with our goal of bringing the 2007 solicitation to conclusion by the end of 2007.

23. The assigned Commissioner or ALJ should set a schedule for the filing and service later this year of 2008 draft RPS Plans; should set a schedule related to TRCRs; and the assigned Commissioner should determine whether draft TRCRs should be modified, or other steps taken, before the TRCRs are used in the ranking of bids.

24. Each IOU should continue to seek ways to improve the organization, completeness, comprehensiveness and ease of use of its RPS Plan, including an improved (and possibly common) form and format.

25. Evidentiary hearing is not necessary.

26. This proceeding should remain open.

27. This order should be effective today so that the 2007 RPS solicitation may proceed without delay.

O R D E R

IT IS ORDERED that:

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

a. The Pacific Gas and Electric Company (PG&E) "2007 Renewable Energy Procurement Plan and Draft Solicitation Protocol" filed September 26, 2006.

b. The Southern California Edison Company (SCE) "2007 Renewables Portfolio Standard Procurement Plan" filed September 25, 2006.

c. The San Diego Gas & Electric Company (SDG&E) "2007 Renewable Procurement Plan" filed September 25, 2006.

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

a. Within 15 days of the date this order is mailed, PG&E, SCE and SDG&E shall each file with the Director of the Energy Division, and serve on the service list, an amended Plan consistent with all the orders in this decision, plus all guidance in this decision with which the utility agrees. The orders and guidance are summarized in, but not limited to, Appendix A.

b. Unless suspended by the Energy Division Director within 22 days of the date this order is mailed, each utility shall use its amended Plan for its next solicitation.

3. The 2007 RPS procurement cycle shall be as stated in Appendix B. The schedule may be modified by the 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 Commission Rules of Practice and Procedure).

4. Consistent with all prior Commission orders and directions, each utility ultimately remains responsible for reasonable RPS 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 Plan. The Commission shall also judge contract results, program results, and non-compliance pleadings by, but is 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 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.

5. The assigned Commissioner or ALJ in this proceeding (or its successor proceeding with regard to ongoing implementation and administration) shall set a schedule for the filing and service later this year of draft RPS Plans for the 2008 solicitation, and subsequent draft RPS Plans, as necessary. The assigned Commissioner or ALJ shall set a schedule for matters related to Transmission Ranking Cost Reports (TRCRs) to be used in the ranking of bids in an RPS solicitation. The assigned Commissioner shall assess the adequacy of each TRCR based on filed comments and reply comments, and shall determine whether each TRCR shall be approved, modified, or other steps taken before a TRCR is used in ranking bids in an RPS solicitation.

6. This proceeding remains open.

This order is effective today.

Dated February 15, 2007, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
Commissioners

APPENDIX A

REVIEW OF AND CHANGES TO 2007 PLANS

Pursuant to the discussion in the attached decision, and using the same order of presentation, we adopt the following for the three investor-owned utilities (IOUs), namely Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E). We also include procedural guidelines for Commission review of proposed contracts.

1. **Credit Requirements**

    a. Accept PG&E's proposal to reduce a portion of its Project Development Security for PG&E's Plan.

    b. Encourage IOUs to reconsider all deposit and collateral policies and amounts in order to reach a proper balance of competing interests while at the same time being compatible with efficient and equitable allocation of risk.

2. **Utility-Owned Projects**

    a. Accept PG&E's proposal to include a solicitation item regarding "sites for development," and encourage SCE and SDG&E to adopt a similar item.

    b. Encourage further consideration by each IOU of building RPS resources as needed to achieve RPS Program goals.

3. **Financial Disclosures, Rate Adjustments and Change in Law**

    a. Adopt PG&E's proposed clarification of financial disclosures being required, if at all, no sooner than after the project is on an IOU's short list (with no requirement for disclosures to either submit a bid or permit initial consideration of a bid), and adopt this for all three IOUs.

b. Encourage IOUs and all parties to give further consideration to the issue of project-specific financial information in light of what is truly needed to assess project viability while also considering reasonable risk sharing, if any, over the term of the agreement.

c. Reject SDG&E's proposal to permit seeking rate relief for costs related to debt equivalency and FIN 46(R) in the advice letter filing for approval of an RPS PPA, but note such relief is available in other proceedings, as needed.

d. Encourage IOUs and parties to consider a "change in law" clause (to address how parties will handle new or revised laws, regulations or rules over the term of the contract), with recognition that contract administration is subject to ongoing Commission oversight.

4. **Waivers:** Encourage IOUs to rethink the tone and nature of waivers and disclaimers.

5. **Scheduling Coordinator (SC)**

a. Decline to order each IOU to offer SC services.

b. Accept SCE's proposal for SCE to offer SC services, but require those services to be offered as an option and not be mandatory.

c. Accept SCE's proposal relative to SCE that operators take the risk of operational deviations outside an established bandwidth.

6. **Evaluation Criteria and Selection Process**

a. Require each IOU's amended Plan to do a better job of stating evaluation criteria and selection process.

b. Encourage the IOUs to draft a common evaluation criteria and selection process description to insert into each Plan, with unique language to reflect differences, as needed.

7. **Senate Bill (SB) 107**

   a. Renewable Energy Credits (RECs):

      i. Adopt the definition of REC proposed by PG&E for all three IOUs, and SCE's additional language for SCE regarding conformance with SB 107 (noting SCE and SDG&E may also include PG&E's definition of "Law" as they determine necessary or appropriate).

      ii. Adopt for all three IOUs a revised non-modifiable term that changes "Environmental Attributes" to "Green Attributes" and incorporates proposals on RECs and concepts in Assembly Bill (AB) 32.

   b. Agreement Information: Adopt PG&E proposal for PG&E to delete sentence that is inconsistent with the SB 107 time period; require SDG&E to do the same; adopt SDG&E proposal to include information on online date and delivery point, also include expected deliveries (energy) and length of contract, and require this of all three IOUs.

   c. Access to Bid Information: Lift restrictions on an electrical corporation transmitting or sharing bid results with the Commission before Commission establishment of the market price referent.

   d. Timing: Permit parties to include relevant changes related to SB 107 mandates (e.g., include definition of REC and changes to "Green Attributes") in any contract submitted for Commission consideration on or after January 1, 2007, even if from a prior solicitation (e.g., 2004, 2005, 2006), but not require contract renegotiation of executed contracts; contracts executed after the date this order is mailed should include relevant provisions of SB 107.

8. **Commission Review Process**

   a. Existing Commission review process by advice letter is continued.

   b. Other cost recovery: cost recovery related to debt-equivalence or FIN 46(R) must be through cost of capital or other formal proceeding.

9. **RPS Data**: Each IOU may update its RPS data showing in amended Plans to reflect categories identified in D.06-10-050, as each determines best.

10. Issues Specific To An IOU Plan

a. PG&E

i. Updated as needed to reflect current conditions.

ii. Edit its limitations and description regarding relief a bidder may seek regarding the solicitation process, as appropriate.

b. SCE

i. Update as needed to reflect current conditions.

ii. Include equal treatment, fair dealing and good faith performance language in its Procurement Protocol.

iii. Reconsider procurement needs based on a range of scenarios, and commitment to procure to the high needs case.

iv. Correct integration costs to zero, as necessary.

v. Consider better organization and presentation of Plan.

c. SDG&E

i. Update as needed to reflect current conditions.

ii. Complete as needed (e.g., include EEI contract).

11. Schedules and Plan Organization

a. 2007 Solicitation Schedule

i. Timeline in Appendix B is adopted.

ii. Energy Division Director may modify the dates on own initiative to efficiently administer program, but should seek to bring the 2007 solicitation to conclusion by end of 2007, if possible.

iii. Parties may seek modification in the schedule consistent with Commission Rule 16.6.

b. 2008 Solicitation Schedule

i. Specific schedule set by assigned Commissioner or ALJ, with initial filing later in 2007.

ii. Assigned Commissioner of ALJ shall set the schedule for TRCRs and Assigned Commissioner shall issue an assigned Commissioner's Ruling on the TRCRs.

c. Plan Organization and Ease of Use: Encourage each IOU to consider ways to improve each Plan, including adoption of a common form and format, and perhaps an improved model contract, to facilitate its use by all involved parties and entities.

(END OF APPENDIX A)

APPENDIX B

RENEWABLES PORTFOLIO STANDARD
SOLICITATION TIMELINE
(Updated from D.04-07-029, D.05-12-042, D.06-05-039)

- Utilities file applications for consideration of renewables portfolio standard procurement plans (RPS Plans), including requests for offers (RFOs).

- California Public Utilities Commission (CPUC) decision on RPS Plans, including RFOs.

- Utilities file amended RPS Plans, as needed.

- Utilities issue RFOs (unless amended RPS Plans are suspended by the Energy Division Director).

- Respondents file notice of intent to bid.

- Bidders conferences held.

- Deadline for respondents to submit bids.

- Utilities validate and clarify bids.

- Utilities notify CPUC Executive Director by letter when bidding has closed.

- Market price referent (MPR) is calculated by CPUC when last solicitation is complete.

    CPUC staff calculates and discloses draft MPR in a draft resolution. After party comments, MPR is finalized when CPUC adopts MPR resolution.

- Utilities evaluate the bids to develop short lists.[1]

  Procurement Review Group (PRG) meetings are held to review bid results.

- Utilities submit short-listed bids to CPUC and PRGs.

  Utilities' initial reports on evaluation criteria and selection process are included with short-list, or shortly thereafter; Independent Evaluator's Preliminary Reports are also included, or shortly thereafter.

  Bidders have five days to withdraw all conflicting bids. Otherwise bid is binding.

- CPUC and PRGs review utilities' short lists.

- Utilities and bidders negotiate and execute contracts.

- Utilities file contracts by advice letter or application for CPUC consideration.

  Filing includes updated utility report on evaluation criteria and selection process, and final Independent Evaluator's Report.

  Utilities may file contracts in groups, as appropriate. Contracts that do not require Supplemental Energy Payments (SEP) funds may be submitted separately.

- Contracts are considered and addressed by CPUC in a resolution or decision.

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[1] Utility evaluation process should begin prior to MPR release and adoption.

- Sellers confirm Public Goods Charge (PGC) funding with utilities within 10 days after receiving notice of SEP determination from Energy Commission.

  After SEP determination is made, generators and utilities may re-structure payment streams in their contract or take other actions in accordance with Standard Terms and Conditions, "SEP Awards, Contingencies," based on SEP determination.

  If SEP award is not made within 120 days of submission of the contract for CPUC approval, generators may exercise termination rights under the provisions of Standard Terms and Conditions, "SEP Awards, Contingencies."

- If necessary, utilities submit amended advice letters or applications with revised proposed contracts, reflecting results of SEP determinations, to CPUC for review and approval by resolution or decision.

NOTE ON SEPs

Contracts approved by CPUC and having a contract price greater than the MPR may be eligible for SEPs. The Energy Commission's instructions for submitting applications and supporting materials are set forth in the current *New Renewable Facilities Program Guidebook*, available at http://www.energy.ca.gov/renewables/documents/index.html.

Thirty days after receiving a contract and all relevant data required to conduct the SEP evaluation, the Energy Commission releases PGC Funding Confirmations to CPUC, utility, and individual bidder, and will identify any caps imposed. Final SEP awards are subject to conditions identified in the current *New Renewable Facilities Program Guidebook*.

ADOPTED SCHEDULE
FOR 2007 SOLICITATION

LINE NO	ITEM	NO. OF DAYS	DATES
1	Commission's Conditional Approval of RPS Plans	0	2/15/07
2	IOUs file amended RPS Plans	15	3/2
3	IOUs issue RFOs (unless amended Plans are suspended by Energy Division Director by Day 22)	25 (a)	3/12 (a)
4	IOUs notify Commission when bidding is closed	113	6/8
5	IOUs submit short lists to Commission and PRG	151	7/16
6	IOUs submit report on evaluation criteria and section process; Independent Evaluators submit Preliminary Reports	165	7/30
7	IOUs submit ALs with PPAs for Commission consideration	by 319	by 12/31

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 25, as necessary, without Commission approval.

(END OF APPENDIX B)

APPENDIX C

CHANGE IN LAW

Electric Corporations subject to the Renewables Portfolio Standards (RPS) Program may, for the purpose of future procurement plans, consider the following example of a change in law provision. This example is from an interconnection agreement between two telecommunications carriers.

> "This Agreement is entered into as a result of both private negotiation between the Parties and the incorporation of some of the results of arbitration by the California Public Utilities Commission. If the actions of the State of California or federal legislative bodies, courts, or regulatory agencies of competent jurisdiction invalidate, modify, or stay the enforcement of laws or regulations that were the basis or rationale for a provision of the contract, the affected provision shall be invalidated, modified, or stayed, consistent with the action of the legislative body, court, or regulatory agency upon the written request of either party. In the event of any such actions, the Parties shall expend diligent efforts to arrive at an agreement respecting the appropriate modifications to the Agreement. If negotiations fail, disputes between the Parties concerning the interpretation of the actions required or provisions affected by such governmental actions shall be resolved pursuant to the dispute resolution process provided for in this Agreement. The Parties acknowledge the following: Verizon v. FCC, et. al, 535 U.S. 467 (2002); USTA, et. al v. FCC, 290 F.3d 415 (D.C. Cir. 2002) and following remand and appeal, USTA v. FCC, 359 F.3d 554 (D.C. Cir. 2004); the FCC's Triennial Review Order, CC Docket Nos. 01-338, 96-98 and 98-147 (FCC 03-36) including, without limitation, the FCC's MDU Reconsideration Order (FCC 04-191) (rel. Aug. 9, 2004) and the FCC's Order on Reconsideration (FCC 04-248) (rel. Oct. 18, 2004), and the FCC's Biennial Review Proceeding; the FCC's Order on Remand (FCC 04-290), WC Docket No. 04-313 and CC Docket No. 01-338 (rel. Feb. 4, 2005) ("TRO Remand Order"); the FCC's Report and Order and Notice of Proposed Rulemaking (FCC 05-150), CC Docket Nos. 02-33, 01-337, 95-20, 98-10 and WorldCom

Docket Nos. 04-242 and 05-271 (rel. Sept. 23, 2005) ("Title I Order"); the FCC's Supplemental Order Clarification (FCC 00-183) (rel. June 2, 2000), in CC Docket 96-98; and the FCC's Order on Remand and Report and Order in CC Dockets No. 96-98 and 99-68, 16 FCC Rcd 9151 (2001), (rel. April 27, 2001), which was remanded in WorldCom, Inc. v. FCC, 288 F.3d 429 (D.C. Cir. 2002), and as to the FCC's Notice of Proposed Rulemaking as to Intercarrier Compensation, CC Docket 01-92 (Order No. 01-132) (rel. April 27, 2001) (collectively, "Government Actions"). The Parties further acknowledge and agree that by executing this Agreement, neither Party waives any of its rights, remedies or arguments with respect to such Government Actions and any remand thereof, including its rights under this Intervening Law paragraph."

(Source: Interconnection Agreement between AT&T-California and Verizon Business, General Terms and Conditions Appendix, Section 23, Intervening Law; Approved by the Commission in Decision 06-08-029, August 23, 2006.)

(END OF APPENDIX C)