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TO PARTIES OF RECORD IN RULEMAKING 11-05-005

This is the proposed decision of Administrative Law Judge Regina DeAngelis. This item is targeted to appear on Agenda No. 3326 for the Commission's November 14, 2013 Business Meeting, but may appear on a later agenda. Interested persons may monitor the Business Meeting agendas, which are posted on the Commission's website 10 days before each Business Meeting, for notice of when this item may be heard. The Commission may act on the item at that time, or it may hold an item to a later agenda.

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the proposed decision as provided in Article 14 of the Commission's Rules of Practice and Procedure (Rules), accessible on the Commission's website at www.cpuc.ca.gov. Pursuant to Rule 14.3, opening comments shall not exceed 15 pages.

Comments must be filed pursuant to Rule 1.13 either electronically or in hard copy. Comments should be served on parties to this proceeding in accordance with Rules 1.9 and 1.10. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ KAREN V. CLOPTON
Karen V. Clopton, Chief
Administrative Law Judge

KVC:lil

Attachment

Decision **PROPOSED DECISION OF ALJ DEANGELIS** (Mailed 10/15/2013)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	Rulemaking 11-05-005 (Filed May 5, 2011)

DECISION CONDITIONALLY ACCEPTING 2013 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS AND INTEGRATED RESOURCE PLAN AND ON-YEAR SUPPLEMENT

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DECISION CONDITIONALLY ACCEPTING 2013 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS AND INTEGRATED RESOURCE PLAN AND ON-YEAR SUPPLEMENT

1. Summary

Pursuant to the authority provided in Pub. Util. Code § 399.13(a)(1),[1] today's decision conditionally accepts, as modified herein, the draft 2013 Renewables Portfolio Standard (RPS) Procurement Plans, including the related solicitation protocols, filed by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).

We direct PG&E, SCE, and SDG&E to file final 2013 RPS Procurement Plans with the Commission to initiate the RPS solicitation process for 2013 within 14 days of the mailing date of this decision pursuant to the 2013 RPS solicitation schedule adopted herein.

In this decision, we address the significant modifications in the 2013 RPS Procurement Plans, as compared to the 2012 Plans, presented by PG&E, SCE, and SDG&E, as set forth in the June 28, 2013 draft Plans and updated on

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[1] Section 399.13(a)(1) provides, in full, as follows: "The commission shall direct each electrical corporation to annually prepare a renewable energy procurement plan that includes the matter in paragraph (5), to satisfy its obligations under the renewables portfolio standard. To the extent feasible, this procurement plan shall be proposed, reviewed, and adopted by the commission as part of, and pursuant to, a general procurement plan process. The commission shall require each electrical corporation to review and update its renewable energy procurement plan as it determines to be necessary." All subsequent code section references are to the Public Utilities Code unless otherwise indicated.

August 28, 2013.[2] We also defer consideration of several issues related to PG&E's, SCE's, and SDG&E's RPS procurement activities to later in this or other proceedings.

This decision also conditionally accepts the Integrated Resource Plan and On-Year Supplement filed by PacifiCorp, a multi-jurisdictional utility, as modified herein. We direct PacifiCorp to file a final 2013 On-Year Supplement with the Commission within 14 days of the mailing date of this decision.

This decision accepts the RPS Procurement Plans filed by two smaller utilities, Bear Valley Electric Service, a Division of Golden State Water Company, and Liberty Utilities LLC (formerly California Pacific Electric Company, LLC).[3] Pursuant to § 365.1(c)(1)[4] and Decision (D.) 11-01-026, this decision accepts the RPS Procurement Plans filed by electric service providers (ESPs).[5] We deem the

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[2] SDG&E filed its 2013 Draft RPS Procurement Plan on June 18, 2013, rather than June 28, 2013.

[3] On September 12, 2013, Liberty Utilities (CalPeco Electric) LLC (formerly California Pacific Electric Company) filed a Notice of Name Change in this proceeding indicating that the utility's name is now Liberty Utilities (CalPeco Electric) LLC.

[4] Section 365.1 was enacted by Senate Bill 695 (Kehoe, Stats. 2009, ch. 337) and provides, among other things, for the phased and limited reopening of direct access transactions in the service territories of the three large utilities. The statute also requires that, once the Commission has begun the process of reopening direct access, the Commission shall equalize certain program requirements between the three large utilities and "other providers," including electric service providers. § 365.1 expressly exempts community choice aggregators from this requirement.

[5] Section 365.1 and D.11-01-026, *Decision Revising Rules for the Renewables Portfolio Standard Pursuant to Senate Bill 695* (January 13, 2011). In D.11-01-026, the Commission found that almost all significant RPS requirements currently apply equally to large utilities and ESPs. The decision adds to the RPS obligations of ESPs, such as the filing of RPS Procurement Plans for Commission acceptance. D.11-01-026 at 28 (Ordering Paragraph 1).

filings of the ESPs and the two smaller utilities as final 2013 RPS Procurement Plans. No further filings are required.

This proceeding remains open.

2. Procedural History

The California Renewables Portfolio Standard Program (RPS Program) was established by Senate Bill (SB) 1078, effective January 1, 2003 (Sher, Stats. 2002, ch. 516).[6] This legislation established, among other things, that the amount of electricity procured per year from eligible renewable energy resources, as defined therein, would be an amount equal to at least 20% of the total electricity sold to retail customers in the state by December 31, 2017. The Legislature accelerated this goal to 20% by 2010 in SB 107 (Simitian, Stats. 2006, ch. 464). In 2011, SB 2 of the 2011-2012 First Extraordinary Session (Simitian, Stats. 2011, ch. 1) (SB 2 1X) made significant changes to the RPS Program, most notably extending the RPS goals from 20% of retail sales of California's investor-owned utilities (utilities or IOU), electric service providers (ESPs), and community choice aggregators (CCAs) by the end of 2010 to 33% of retail sales of utilities, ESPs, and CCA and publicly owned utilities by 2020.[7] SB 2 1X also modified or changed many details of the RPS Program, including creating

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[6] The RPS statute is codified at §§ 399.11-399.32.

[7] SB 2 1X was enacted by the Legislature in 2011 in the 2011-2012 First Extraordinary Session effective on December 10, 2011. AB 327 (Perea, Stats, 2013, ch. 611), which, among other things establishes the 33% requirement as a floor (not a ceiling), was signed by the Governor on October 7, 2013.

Portfolio Content Categories[8] for RPS procurement and establishing specific compliance periods for measuring compliance with the 33% goals.[9]

This rulemaking was initiated to, among other things, implement SB 2 1X and for the continued administration of the RPS Program.[10]

On May 10, 2013, the assigned Commissioner initiated the 2013 procurement portion of this proceeding by issuing a ruling, entitled *Assigned Commissioner's Ruling Identifying Issues and Schedule of Review for 2013 Renewables Portfolio Standard Procurement Plans Pursuant to Public Utilities Code Sections 399.11 et seq. and Requesting Comments on a New Proposal* (May 10, 2013 ACR).

The May 10, 2013 ACR directed utilities and ESPs to file RPS Procurement Plans for 2013 on or before June 28, 2013.[11] In accordance with the May 10, 2013 ACR, utilities and ESPs filed their 2013 RPS Procurement Plans describing the actions that would be undertaken to meet their RPS Program procurement

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[8] Portfolio Content Categories for the RPS Program are set forth in § 399.16 and were added to the statute by SB 2 1X in 2011. The Commission defined and implemented these code provisions in D.11-12-052, *Decision Implementing Portfolio Content Categories for the Renewables Portfolio Standard Program* (December 15, 2011). This decision sets forth the criteria required for generation from eligible-renewable resources to be counted as Category 1, Category 2, or Category 3 under § 399.16(b)(1)-(3).

[9] D.11-12-020 *Establishes Procurement Quantity Requirements for Retail Sellers* sets the procurement quantity requirements for the RPS Program.

[10] Rulemaking (R.) 11-05-005, *Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program* at 8. This rulemaking was adopted by the Commission on May 5, 2011.

[11] May 21, 2013 Letter granting SCE, PG&E, and SDG&E's request for a two-week extension to file.

requirements.[12] These plans include many aspects, such as compliance with General Order 156 and § 8283, as amended by Assembly Bill (AB) 1386.[13]

Section 8283 is the statutory provision requiring utilities to submit plans for "increasing procurement from women, minority, and disabled veteran business enterprises in all categories, including, but not limited to, renewable energy…." Two Commissioners addressed the application of § 8283 to the RPS Plan in a concurrence filed with D.12-11-016, stating "[b]ecause of the importance of California's RPS, it must be inclusive of California's dynamic and ever-evolving demographics, and the entities that bid into the RPS solicitations should not be exempted from the core value of diversity in utility procurement."[14] We affirm this statement today.

On August 28, 2013, utilities and ESPs submitted updates to their previously filed draft plans. These updates include responses to the July 24, 2013

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[12] PG&E, SCE, and SDG&E did not file Transmission Ranking Cost Reports (TRCRs). TRCR has been a required filing in past years. TRCRs were used to provide estimated transmission cost data in the least cost, best fit (LCBF) evaluation of bids and by the utilities for the purpose of establishing a relative ranking of bids. *See, e.g.,* D.04-07-029, *Opinion Adopting Criteria For the Selection of Least-Cost and Best-Fit Renewable Resources* (July 8, 2004). In D.12-11-016, the Commission required that bids have a minimum of a completed California Independent System Operator Generator Interconnection Procedures Phase I (or equivalent) study to bid into a solicitation and that these studies, rather than the TRCRs, should be used in LCBF evaluations to estimate transmission costs. D.12-11-016, Ordering Paragraph 11 at 92. For this reason, the Commission no longer requires the filing of TRCRs. *See also,* May 10, 2015 ACR at 16-17.

[13] AB 1386 (Bradford, Stats. 2011, ch. 443).

[14] D.12-11-016 at 97, *Concurrence of Commissioners Peevey and Simon.*

ALJ ruling requesting additional information pertaining to safety considerations, if any, as related to the procurement plans.[15]

The May 10, 2013 ACR also presented a proposal for revising the RPS procurement planning and review process. The proposal presented in the ACR included a two-year RPS procurement planning cycle. Parties submitted comments on this proposal. A similar proposal was presented to parties last year and, at that time, the Commission declined to adopt any changes to the existing annual filing requirements.[16] We adopt minor revisions to this process today.

The smaller utilities filed 2013 RPS Procurement Plans, including Bear Valley Electric Service, a Division of Golden State Water Company, and Liberty Utilities LLC (CalPeco Electric). These smaller utilities are subject to a subset of the filing requirements.[17] PacificCorp, the only multi-jurisdictional utility, is permitted by statute to file an Integrated Resource Plan which is prepared for regulatory agencies in other states provided that the Integrated Resource Plan complies with the requirements under California law.[18] PacifiCorp filed this document on April 30, 2013 and an On-Year Supplement on May 30, 2013.

The following ESPs filed 2013 RPS Procurement Plans: 3 Phases Renewables, Calpine PowerAmerica-CA, LLC, Commercial Energy of California,

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15 *Administrative Law Judges' Ruling Requiring a Supplemental Filing to the 2013 Procurement Plans to Address Safety Considerations* (July 24, 2013).

16 D.12-11-016 at 64.

17 May 10, 2013 ACR at 8, § 399.18(a)(5) and § 399.18(b).

18 Section 399.17(d) and D.08-05-029, as modified by D.09-11-014, *RPS Participation on Participation of Small and Multi-Jurisdictional Utilities in Renewables Portfolio Standard Program*.

Consolidated Edison Solutions, Inc., Constellation NewEnergy, Inc., Direct Energy Business, LLC, Direct Energy Service, LLC, EDF Industrial Power Services (CA), LLC, EnerCal USA, LLC, Gexa Energy California, LLC, Liberty Power Delaware, LLC (Liberty Power Delaware), Liberty Power Holdings, LLC, Noble Americas Energy Solutions LLC, Pilot Power Group, Inc., Praxair Plainfield, Inc. (Praxair), Shell Energy North America (US), L.P., Southern California Telephone & Energy, Tiger Natural Gas, Inc. The ESPs are subject to a subset of the filing requirements.[19]

For the 2012 Plan, the Administrative Law Judge (ALJ) requested the use of Energy Division's proposal regarding the renewable net short (RNS) methodology[20] set forth in a July 11, 2012 ruling.[21] For the 2013 Plans, we requested the utilities and ESPs to use the same 2012 RNS methodology for calculating the RNS.[22] Several parties filed comments regarding PG&E's, SCE's, and SDG&E's RNS calculations. In response, Energy Division Staff plans to release another RNS methodology by ALJ ruling for use by the utilities in the 2013 solicitation. We expect utilities to rely on this revised RNS methodology for any remaining components of the 2013 solicitation.

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19 May 10, 2013 ACR at 8.

20 RNS refers to the amount of new renewable generation necessary for retail sellers to meet or exceed the renewable procurement quantity requirements.

21 The assigned ALJ issued a ruling on August 2, 2012 to enter the Energy Division's final RNS methodology into the record and directed the use of that methodology in the August 15, 2012 updates to the 2012 RPS Procurement Plans.

22 May 10, 2013 ACR at 12 and fn. 19, (RNS methodology from August 2, 2012 ALJ Ruling, entitled *Administrative Law Judge's Ruling (1) adopting renewable net short calculation methodology (2) incorporating the attached methodology into the record, and (3) extending the date for filing updates to 2012 Procurement Plans*).

The major modifications of the RPS Procurement Plans filed by Pacific Gas and Electric Corporation (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) are addressed in today's decision.

This proceeding remains open.

3. Overview of 2013 RPS Procurement Plan Requirements

The 2013 draft RPS Procurement Plans filed by PG&E, SCE, and SDG&E include a number of components.[23] The Public Utilities Code requires that specific matters be addressed in an electric corporation's RPS procurement plan, including: (1) assessment of RPS portfolio supply and demand; (2) potential compliance delays; (3) project status update; (4) risk assessment; (5) quantitative information; (6) bid solicitation protocol, such as LCBF; (7) estimate of transmission costs for RPS procurement; and (8) cost quantification.[24] The

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[23] For example, PG&E's 2013 Draft RPS Procurement Plans includes (1) Quantitative Information at Appendix 1 and 1A; (2) 2013 RPS Procurement Information Related to Cost Quantification at Appendix 2; (3) Other Modeling Assumptions Incorporated in Quantitative Information at Appendix 3; (4) Status Update on All RPS Resources Under Contract but Not Yet Delivering Generation at Appendix 4; (5) Expiring Contracts at Appendix 5; (6) Draft 2013 Solicitation Protocol and Attachments at Appendix 6; (7) Redline of Draft 2013 RPS Solicitation Protocol and Attachments at Appendix 7; and (8) Redline of Draft 2013 RPS Procurement Plan at Appendix 8. SCE's and SDG&E's 2013 Draft RPS Procurement Plans include substantially similar information. Some of these documents have been designated confidential. All of these documents are available at the link referred to as the *Docket Card* on the Commission's website.

[24] Section 399.13(a)(5)(A)-(F); D.04-07-029 (setting forth LCBF methodology); SB 836 (Padilla, Stats. 2011, ch. 600, § 1) which imposes new RPS data quantification reports to the legislature.

Commission has established additional requirements and the May 10, 2013 ACR requested specific information for 2013.

Importantly, as set forth in the September 12, 2012 Amended Scoping Memo and October 5, 2012 ACR, certain issues will be addressed by the Commission later in this proceeding, including, but not limited to, implementing statutory requirements set forth in SB 2 1X for the Commission to establish an RPS procurement expenditure limitation for California electrical corporations.[25]

PG&E and SCE filed updates to their June 28, 2013 RPS Procurement Plans on August 28, 2013. PG&E's and SCE's updates contain minor corrections to cost quantification data, changes to solicitation protocols, and updates to their pro forma agreement terms and conditions. Some of these issues are addressed in sections 5 and 6 of this decision.

4. General Issues Related to 2013 RPS Procurement Plans

To the extent the 2013 RPS Procurement Plans filed by PG&E, SDG&E, and SCE raise very similar or the same issues, we address the issues below, in section 4. We address issues unique to PG&E and SCE in sections 5 and 6, respectively. At section 7, we address one issue related to PacifiCorp. At section 8, we address the request by Bear Valley Electric Service for authority to not file annual procurement plans. At section 12, we address the request by two

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[25] Section 399.15(c)-(g) provides, in part, as follows: "The commission shall establish a limitation for each electrical corporation on the procurement expenditures for all eligible renewable energy resources used to comply with the renewables portfolio standard. In establishing this limitation, the commission shall rely on the following: …."

ESPs, Praxair and Liberty Power Delaware to, similarly, reduce their filing requirements.

4.1. Safety Considerations – Amendments to 2013 RPS Plans

On July 24, 2013, the assigned ALJ issued a ruling requesting additional information pertaining to safety considerations, if any, as related to the procurement plans. Parties filed responses to this ruling on August 28, 2013. We find these filings acceptable. We direct all entities filing RPS Procurement Plans in the future to incorporate a section on safety consideration.

4.2. Imperial Valley - Monitoring and Sunrise Powerlink Transmission Project

In today's decision, we require continued monitoring of the utilities' procurement activities in the Imperial Valley area and renewable projects' utilization of the Sunrise Powerlink Transmission Project. We decline to adopt requests for additional actions to further bolster procurement as the evidence indicates sufficiently robust RPS procurement in that area.

On December 18, 2008, the Commission adopted D.08-12-058,[26] which approved the 500-kilovolt Sunrise Powerlink Transmission Project. The 117-mile Sunrise Powerlink Transmission Project runs from Imperial County to San Diego and was energized on June 18, 2012. We have previously addressed issues related to the Sunrise Powerlink Transmission Project in prior RPS Procurement Plan decisions, and we again address related issues as raised by parties in comments to the utilities' draft RPS Procurement Plans.

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[26] D.08-12-058, *Decision Granting a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project* (December 18, 2008).

In the Commission's decision accepting of the 2009 RPS Procurement Plans, the Commission stated it would consider requiring so-called "remedial measures" in future RPS Procurement Plans if "evidence shows that the LCBF methodology fails to properly value Imperial Valley resources and their unique access to transmission, or that there are other infirmities [in the RPS procurement in that area]."[27] The Commission has continued to monitor RPS procurement in this area consistent with the terms set forth in Appendix A of D.09-06-018 but has yet to adopt any remedial measures.[28] As stated in D.09-06-018, the purpose of the monitoring is the recognition that "Sunrise is an important project in California. It deserves reasonable attention to ensure that it is used efficiently, equitably and wisely." The Commission's commitment to this matter was most recently affirmed in the decision accepting the 2012 RPS Procurement Plans.[29]

In comments to the 2013 draft Procurement Plans, Center for Energy Efficiency and Renewable Technologies (CEERT) again suggests that the Commission now (and for the first time) adopt remedial measures to bolster the

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[27] D.09-08-018, *Decision Conditionally Accepting Procurement Plans for 2009 Renewables Portfolio Standard Solicitations and Integrated Resource Plan Supplements* at 17. For more background on the genesis of these remedial measures, refer to the Commission decision approving of the Sunrise Powerlink Transmission Project in D.08-12-058, *Decision Granting a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project* (December 18, 2008).

[28] D.11-04-030, *Decision Conditionally Accepting 2011 Renewables Portfolio Standard Procurement Plans and Integrated Resource Supplements* at 25. In the decision, the Commission reiterated its commitment to consider remedial measures in the future, as needed, but declined to adopt them.

[29] The Commission addressed Imperial Valley in D.12-11-016, *Decision Conditionally Accepting 2012 Renewables Portfolio Standard Procurement Plans and Integrated Resource Plan Off-Year Supplement* at 12-17.

efforts of the utilities to advance meaningful development of new generation in the Imperial Valley and the area interconnected to Imperial Irrigation District (IID).[30] IID and Tenaska Solar Ventures generally agree with CEERT. L. Jan Reid (Reid) opposes any preferences and states that preferences are unnecessary.[31]

As of August 16, 2013, SDG&E has approximately 3,600 gigawatt-hour (GWh) under contract from projects that will be facilitated by the Sunrise Powerlink Transmission Project. The below table lists Commission-approved contracts executed by SDG&E for projects in the Imperial Valley and eastern San Diego County area.

SDG&E's Commission-approved RPS Contracts – As of August 16, 2013

Project	Location	Technology	Capacity (MW)	Energy (GWh)
Calipatria Solar Farm I	Calipatria, CA	Solar PV	20	48
Campo Verde	Fillaree Ranch, CA	Solar PV	139	276
Centinela Solar I	Calexico, CA	Solar PV	110	235
Centinela Solar II	Calexico, CA	Solar PV	30	62
CSolar IV South	El Centro, CA	Solar PV	97	306
CSolar IV West	El Centro, CA	Solar PV	150	381
Energia Sierra Juarez	Jacume, Baja California Norte, MX	Wind	156	324
Silver Ridge Mt. Signal (Imperial Valley Solar I)	Calexico, CA	Solar PV	200	470
Ocotillo Express	Ocotillo, CA	Wind	265	789
Seville I	Calipatria, CA	Solar PV	20	45
SolarGen 2	Calipatria, CA	Solar PV	150	356

30 IID July 12, 2013 comments at 4; *see also*, IID June 27, 2012 comments to 2012 Plans at 6.

31 Reid July 12, 2013 comments at 6-8.

Tierra del Sol, Rugged Solar, Lan West, Lan East	Boulevard and Borrego Springs, CA	Concentrating Solar PV	200	376

Provided that all of the projects listed in the table achieve commercial operation, SDG&E will likely have fulfilled its Sunrise renewables commitment in D.08-12-058. In order to account for potential project failure and ensure achievement of its Sunrise commitment, SDG&E asserts that it continues to consider contracting with projects located in the Imperial Valley region.[32]

In today's decision, again we affirm the Commission's commitment to continue monitoring renewable procurement activities in Imperial Valley. We decline, however, to adopt the requests for additional oversight mechanisms based on, among other things, the continued robust procurement in the area, as indicated by the amount of capacity currently under contract in the Imperial Valley region and the robust interest for project development based on the results of prior solicitations and the Independent Evaluator's report.[33]

Accordingly, the Commission's Energy Division Staff is directed to continue to monitor RPS development in the Imperial Valley according to the parameters set forth in Appendix A of D.09-06-018. Consistent with D.12-11-016, PG&E, SCE, and SDG&E are directed to provide a specific assessment of the offers and contracted projects in the Imperial Valley region in future RPS Procurement Plans filed with the Commission pursuant to § 399.11 *et seq*. until directed otherwise.

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[32] SDG&E Draft 2013 RPS Procurement Plan at 44.

[33] SDG&E Draft 2013 RPS Procurement Plan at 43; SCE Draft Amended 2013 RPS Procurement Plan at 34; PG&E Advice Letter 4238-E, June 7, 2013, sec. 2 (Independent Evaluator's Report) at 58.

4.3. Existing Facilities/Expiring Contracts – No LCBF Tie-Breaker

In today's decision, we refrain from requiring any additional LCBF value be applied to offers from existing facilities to promote contracts with existing facilities over new projects in the event two contracts are equally ranked because the value of existing facilities is now reflected in the various contract evaluation methodologies, including LCBF, used by the utilities and the Commission.

In comments on the draft 2013 Procurement Plans, NextEra Energy Resources, LLC (NextEra) suggests that the Commission adopt a policy to maximize the reliance on existing facilities or repowering at existing sites. More specifically, NextEra suggests that the Commission adopt a preference in the form of a LCBF tie-breaker in favor of existing facilities.[34] In support of its request, NextEra points to a number of benefits associated with contracts with existing facilities.

The Commission recognizes that the amount of generation in the utilities' RPS portfolios from projects currently operational is expected to decline through the end of the decade due to contracts expiring.[35] We estimate that the amount of expiring contracts over the next 10 years (i.e., through 2023) to be 4,876 Megawatt (MW) or 19,899 GWh. For this reason, the May 10, 2013 ACR specifically requested the utilities to provide information on all contracts expected to expire in the next 10 years.[36] In the table below, we have compiled

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[34] NextEra July 12, 2013 comments at 8.

[35] May 10, 2013 ACR at 20-21.

[36] May 10, 2013 ACR at 21.

the data provided by the utilities to show the capacity expiring per year by technology through 2023.

Estimated Capacity (MW) in Existing RPS Contracts Expiring through 2023

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Grand Total (MW)
Biogas	11	14		2	4		2	0		6	1	40
Biomass		7	36	128	116	81	60	109	8	1		545
Conduit Hydro					6							6
Geothermal	2	200	53	34	298	151	167	32	250		37	1224
Small Hydro	8	15	27	36	44	2	40	73	22	16	51	335
Solar			44		105		70	80	80	0	0	379
Wind	182	223	695	176	84	143	259	104	219	94	126	2306
Grand Total	204	460	855	376	656	378	597	398	579	116	216	4835

NextEra also suggests that utilities may identify reasons to evaluate existing facilities, in certain instances, as not needed, stating:[37]

> Some statements in the RPS Plans also suggest that Existing Facilities are not needed because utilities have procured sufficient new resources to meet their RPS requirements in the coming years. Although Existing Facilities are eligible to participate in the upcoming 2013 RPS solicitations where they will compete for contracts against new projects, the RPS Plans suggest that procurement to date may have replaced or displaced Existing Facilities. For example, to match near-term deliveries from an Existing Facility with the identified near-term RPS need, Existing Facilities with upcoming expiration dates are requested by PG&E's RPS Plan to offer

[37] NextEra July 12, 2013 comments at 5.

> contract extensions or new contracts at discounted prices, i.e., below current market value[38] Existing Facilities with contracts expiring in later years are also encouraged to participate in an upcoming solicitation or face the risk that their window of opportunity to secure a long-term RPS contract could be lost, again suggesting that these Existing Facilities will be displaced by new projects.[39]

In response to NextEra's claim that the existing contracts should be provided with additional LCBF value to accurately compare existing contracts with new contracts, the utilities state they are open to the idea of encouraging facilities with existing contracts set to expire to bid into the RPS solicitation.[40] The utilities point out, however, that the LCBF methodology already considers qualitative attributes, such as project viability, to ensure that the value of projects with high viability, e.g., projects that are operating, are appropriately considered in the evaluation process.[41] LCBF also reflects the quantitative value of existing facilities in the transmission upgrade cost component.[42]

Regarding the need issue raised by NextEra, PG&E points out that it offers a reasonable approach to existing facilities by encouraging those facilities to

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[38] Footnote to PG&E Draft RPS Procurement Plan at 77; and SDG&E 2013 Draft RPS Procurement Plan at 9.

[39] Footnote to PG&E 2013 Draft RPS Procurement Plan at 17-18.

[40] SCE July 22, 2013 reply comments at 10; PG&E July 22, 2013 reply comments at 10.

[41] SCE July 22, 2013 reply comments at 10.

[42] PG&E July 22, 2013 reply comments at 10.

submit offers for extensions[43] in upcoming solicitations so that these facilities can secure extensions before PG&E fills its long-term net short.[44]

We do not adopt any additional LCBF value for existing facilities. NextEra points to situations, in the above excerpt, where it is possible that bids related to existing contracts will be found less valuable than bids related to a contract with a new facility. It suggests several solutions, including a LCBF tie-breaker concept, to give preference to bids related to an existing facility over new facilities. NextEra appropriately raises the issue of best practices related to recontracting with existing facilities as the market will be reviewing existing contracts with increasing frequency in the upcoming years. NextEra does not, however, acknowledge the complexity of the situation within the current market context and statutory requirements, including, but not limited to, the compliance periods, the Portfolio Content categories requirements, and utilities' overall energy portfolio needs. Further review by staff of these matters is warranted. NextEra also fails to point out the reasons LCBF is not an adequate evaluation method for existing contracts. We tend to agree with PG&E's statement that NextEra is suggesting a "carve out" for existing facilities.[45]

At this point in time, in the 2013 RPS Procurement Plans, and under the current market conditions and statutory framework, we find that the LCBF methodology and other evaluation methods used by utilities currently reflect the

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[43] The term offers for extensions, as used by PG&E, appears to mean offers from sellers with existing contracts to amend and extend the contract term.

[44] PG&E July 22, 2013 reply comments at 10, citing to PG&E Draft 2013 RPS Procurement Plan at 77.

[45] PG&E July 22, 2013 reply comments at 9.

value of contracts with existing facilities. Commission staff is directed to further review expiring contracts within the current market context, statutory requirements, and utilities' energy portfolio optimization strategies.

Accordingly, PG&E, SCE, and SDG&E shall provide information on contracts expected to expire through 2023 in all future RPS Procurement Plans until otherwise directed by the Commission.

4.4. Green Pricing Programs – SDG&E's Connected to the Sun & PG&E's Green Option

In today's decision, we confirm that, while the annual procurement plans filed by PG&E and SDG&E may refer to other applications filed with this Commission for approval of so-called green pricing programs, this decision does not serve to approve of the green pricing options set forth in those separate applications.[46] Moreover, this decision confirms that, if approved, procurement under green pricing programs counts toward RPS requirement only if such procurement meets all the relevant requirements under the Commission's RPS Program.

On January 17, 2012, SDG&E filed Application (A.) 12-01-008[47] seeking authority from the Commission to, among other things, offer "a 20 MW pilot program in an effort to respond to its customers' interest in a green pricing program."[48] SDG&E further states that "It is anticipated that the program will be

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[46] The terms "green pricing options" is used, at times, interchangeably with "green tariff."

[47] A.12-01-008, *Application of San Diego Gas & Electric Company (U 902 E) for Authority to Implement Optional Pilot Program to Increase Customer Access to Solar Generated Electricity.*

[48] SDG&E 2013 Draft RPS Procurement Plans at 12.

fully subscribed, but if the program results in a net excess, SDG&E intends to manage such excess within its Voluntary Margin of Over-Procurement...."[49] under the RPS Program.

On April 24, 2012, PG&E filed A.12-02-040 seeking authority from the Commission for, among other things, "to offer a voluntary program that provides an option for PG&E customers to be 100% renewable through the use of unbundled renewable energy credits (RECs) for the non-RPS-eligible portion of their bill…."[50] PG&E explains that, if the voluntary program is approved, its "residential and commercial customers [could] purchase renewable power up to 100% of their electrical demand. Under the program, PG&E will execute contracts for new renewable generation from facilities to be built within the PG&E service territory sufficient to serve customer loads participating in the program."[51] PG&E further states that "If the Commission approves the Green Option as filed, PG&E would revise its RNS at that time to account for the reduction in the compliance position at that time."[52]

A.12-02-040 and A.12-01-008 (consolidated proceedings) are examples of so-called green pricing options.[53] These Applications are pending before the Commission. No decisions have been issued on these Applications. Today's

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[49] SDG&E 2013 Draft RPS Procurement Plans at 12. SDG&E also refers to other methods that overlap with the RPS Program for addressing excess capacity under its green pricing program.

[50] PG&E 2013 Draft RPS Procurement Plans at 26.

[51] PG&E 2013 Draft RPS Procurement Plans at 26.

[52] PG&E 2013 Draft RPS Procurement Plans at 26.

[53] Applications 12-02-040 and 12-01-008 were consolidated by *Assigned Commissioner's Ruling Granting Motion for Consolidation and Setting Prehearing Conference* (July 31, 2013).

decision makes no findings on these Applications. While aspects of the Applications of PG&E and SDG&E may implicate different components of the RPS Program, the Application proceedings remain the appropriate forum to evaluate the merits of the requested relief until the Commission determines otherwise.[54]

To the extent, however, that PG&E's or SDG&E's Applications seek modifications to the RPS Program, such as PG&E's reference to refining its RPS Program's RNS methodology or SDG&E's reference to managing excess capacity within the RPS Program's Voluntary Margin of Over-Procurement, PG&E and SDG&E must act consistent with the rules of the RPS Program or seek specific changes to the RPS Program. Approval of these separate Applications does not necessarily mean that the RPS Program requirements change to accommodate the programs terms.

4.5. Green Attributes – Pro Form Contract Standard Term and Condition 2

In this decision, we revise a provision referred to as "Green Attributes" in the utilities' pro form forma contracts submitted together with their 2013 draft RPS Procurement Plans. The existing provision is outdated. The revised provision is explained below.

The pro forma contacts of each utility include the standard terms and conditions (STCs) previously approved by the Commission. One of the non-modifiable conditions, referred to as STC 2 and entitled "Green Attributes," is outdated, as well as inconsistent with recent statutory requirements for use of

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[54] SB 43 (Wolk, Stat. 2013, ch. 43) Green Tariff Shared Renewables Program.

biomethane[55] fuel in generation for RPS compliance, as set by AB 2196 (Chesbro), Stats. 2012, ch. 605.[56]

STC 2 contains a long list of attributes that must be conveyed from the seller to the buyer in an RPS contract. This provision has undergone a number of revisions since it was first adopted in D.04-06-014. The environment of RPS procurement in which STC 2 operates has also changed substantially. The most important change is the implementation of the statutory requirement in SB 107 (Simitian), Stats. 2006, ch. 464, that RPS compliance be accounted for in RECs.[57]

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[55] AB 2196 defines "biomethane" as "landfill gas or digester gas, consistent with Section 25741 of the Public Resources Code." Pub. Util. Code § 399.12.6(g).

[56] The text of STC which is superseded today is as follows: "Green Attributes. Seller hereby provides and conveys all Green Attributes associated with all electricity generation from the Project to Buyer as part of the Product being delivered. Seller represents and warrants that Seller holds the rights to all Green Attributes from the Project, and Seller agrees to convey and hereby conveys all such Green Attributes to Buyer as included in the delivery of this Product from the Project."

[57] Section 399.13, as it stood after enactment of SB 107, provided in relevant part:

> The Energy Commission shall do all of the following:…
>
> (b) Design and implement an accounting system to verify compliance with the renewables portfolio standard by retail sellers, to ensure that electricity generated by an eligible renewable energy resource is counted only once for the purpose of meeting the renewables portfolio standard of this state or any other state, to certify renewable energy credits produced by eligible renewable energy resources, and to verify retail product claims in this state or any other state. In establishing the guidelines governing this accounting system, the Energy Commission shall collect data from electricity market participants that it deems necessary to verify compliance of retail sellers, in accordance with the requirements of this article and the California Public Records Act (Chapter 3.5 (commencing with Section 6250) of Division 7 of Title 1 of the Government Code). In seeking data from electrical corporations, the Energy Commission shall request data from the commission. The commission shall collect data from electrical corporations and remit the data to the Energy Commission within 90 days of the request.

Footnote continued on next page

An initial response to this mandate was simply to add RECs to the list of green attributes in STC.[58] Subsequently, in D.08-08-028, the Commission provided a complete definition of a REC, including the environmental attributes included in the REC.[59]

As a result of the REC definition provided by D.08-08-028, the "Green Attributes" term that now includes RECs (as defined), contains redundant, overlapping, and possibly inconsistent elements, many of which date from the negotiation of the original version of the standard terms and conditions in 2003-2004. The ad hoc accretion of new elements to STC 2 as new requirements or new perspectives on "green attributes" arise has led to the unintended result that it is virtually impossible to know from reading STC 2 what attributes are actually conveyed in an RPS contract.

Fortunately, it is not necessary to parse through the existing STC 2 and undertake more "fixes" in order to make STC 2 more useful. The use of RECs as the measure of RPS compliance means that the new STCs REC-1, REC-2, and REC-3 adopted in D.10-03-021,[60] completely describe the attributes (i.e., RECs) that must be conveyed in a contract to be used for RPS compliance. STC 2, as it now stands, is superfluous for RPS compliance, and, therefore, should no longer

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> (c) Establish a system for tracking and verifying renewable energy credits that, through the use of independently audited data, verifies the generation and delivery of electricity associated with each renewable energy credit and protects against multiple counting of the same renewable energy credit. The Energy Commission shall consult with other western states and with the Western Electricity Coordinating Council in the development of this system.

[58] D.07-02-011 at 39-43 and Conclusion of Law 14, as modified by D.07-05-057.

[59] D.08-08-028 at Ordering Paragraph 1.

[60] D.10-03-021 at Ordering Paragraph 35.

be required (i.e., non-modifiable) in RPS contracts. Instead, the current language of STC-2 should be eliminated, and a new, STC 2 should be included to implement the requirements of AB 2196 relevant to RPS procurement contracts, which are codified at Section 399.12.6(c) and (f).

Several of the parties commenting on STC 2 in response to questions asked in the *Second Assigned Commissioner's Ruling Issuing Procurement Reform Proposals and Establishing a Schedule for Comments on Proposals* (October 5, 2012), noted that parts or all of STC 2 have served a useful commercial function. Nothing in this decision is intended to prohibit parties from negotiating any additional contract terms that incorporate some or all of the elements of the prior STC 2, so long as they do not conflict with the new STC 2. The new STC will not retain the "non-modifiable" status.

The new STC 2 is set forth below:

Standard Term and Condition 2

Bioenergy Transactions

1. For all electric generation using biomethane as fuel, Seller shall transfer to Buyer sufficient renewable and environmental attributes of biomethane production and capture to ensure that there are zero net emissions associated with the production of electricity from the generating facility using the biomethane.

2. For all electric generation using biomethane as fuel, neither Buyer nor Seller may make a marketing, regulatory, or retail claim that asserts that a procurement contract to which that entity was a party resulted, or will result, in greenhouse gas reductions related to the destruction of methane if the capture and destruction is required by law. If the capture and destruction of the biomethane is not required by law, neither Buyer nor Seller may make a marketing, regulatory, or retail claim that asserts that a procurement contract to which that entity was a party resulted, or will result, in greenhouse gas reductions related to the destruction of methane, unless the

> environmental attributes associated with the capture and destruction of the biomethane pursuant to that contract are transferred to Buyer and retired on behalf of the retail customers consuming the electricity associated with the use of that biomethane, or unless Seller's procurement contract with the source of biomethane prohibits the source of biomethane from separately marketing the environmental attributes associated with the capture and destruction of the biomethane sold pursuant to that contract, and such attributes have been retired.

AB 2196 carries forward the concept of "net zero emissions" associated with the production of electricity from biomethane that is in the current STC 2 (although the current STC 2 includes biomass as well as biomethane as a fuel source). The Commission has not fully explored how the "net zero emissions" concept will be put into practice in the context of RPS compliance. The Commission's implementation of SB 1122 (Rubio), Stats. 2012, ch. 612, adding 250 MW of generation from bioenergy sources to the feed-in tariff program authorized by Section 399.20, is a logical opportunity to explore this concept further.

Accordingly, in the final 2013 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, PG&E, SCE, and SDG&E shall incorporate the STC 2 adopted by this decision for use in all contracts for RPS procurement signed on or after January 1, 2014. The STC 2 adopted today supersedes the existing STC 2.

4.6. Modifications to the RPS Bid Solicitation Protocols

On June 28, 2013, pursuant to § 399.13(a)(5)(C) and in response to the May 10, 2013 ACR, PG&E, SCE, and SDG&E submitted solicitation protocols as part of their draft 2013 RPS Procurement Plans.[61] These solicitation protocols included, among other things, the following information: solicitation goals, bid eligibility requirements, terms for participating in the solicitations, descriptions of the solicitation process, descriptions of LCBF bid evaluation methodologies, and pro forma agreements.

The bid solicitation protocols seek to provide specific information on the parameters of the forthcoming RPS solicitation. More specifically, the bid solicitation protocols state the utilities' unmet need for eligible RPS resources and desired deliverability characteristics of those resources, such as, online date and locational preferences, and other statutory or Commission-mandated requirements.

In contrast to the 2012 bid solicitation protocols, the 2013 bid solicitation materials include several new protocols, including (1) use of a non-zero cost integration adder; (2) use of third-party resource adequacy; and (3) minimum progress in the interconnection process. A proposal to eliminate the exclusive negotiation of contracts on the shortlist was also submitted by California Wind Energy Association (CalWEA). These modifications and the extent to which we accept these modifications are addressed below.

4.6.1. Integration Cost Adders and Related Contract Modifications

In this decision, we decline to accept SCE's and PG&E's requests to use non-zero integration cost adders as part of the LCBF evaluation of bids and contracts in the 2013 RPS Procurement Plans. We made the same determination

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[61] SDG&E submitted on June 14, 2013.

in D.12-11-016. We also decline to accept PG&E's proposal to require sellers to bear all integration-related charges attributable to its resource output.

It is clear from party comments and the statements by SCE and PG&E in their 2013 draft RPS procurement Plans that the Commission should move forward as soon as possible on this issue.[62] The question of how increasing amounts of intermittent generation are impacting grid reliability, quantifying the impact and benefits of various resources to integrate intermittent generation, and what new policies should be adopted to manage the changing electric grid are being addressed in several Commission proceedings, including, for example, R.11-10-023 and R.12-03-014.[63] Integration cost adders are also included as an element that will be reviewed when we examine LCBF methodologies later in this proceeding.

An integration cost adder must be developed and based on an assessment of system–wide grid impacts and the costs to customers. In considering an appropriate RPS integration cost adder, not only should costs to integrate renewables be considered but ways to minimize costs should also be considered. This may include ways that renewable procurement can be used to enhance grid reliability.

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[62] The term "non-zero" means any value above zero. PG&E June 28, 2013 Draft 2013 RPS Procurement Plan at 6, 21, 92, 107, and 135. SCE June 28, 2013 Draft 2013 RPS Procurement Plan.

[63] R.11-10-023, *Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local Procurement Obligations* dated October 20, 2011; and R.12-03-014, *Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans* dated March 22, 2012.

Because an RPS integration adder should depend on a broader assessment of the electric system's needs, parties are encouraged to participate in the California Independent System Operator (CAISO) processes on this topic or in other Commission proceedings, such as R.12-03-014 and R.11-10-023, or in this proceeding, to provide data and cost information to develop a robust and meaningful integration cost adder.

If an integration cost adder is developed through one of the above mentioned public processes, then each utility may seek authority, consistent with any Commission directives, to amend its 2013 RPS Procurement Plan for the purpose of using that integration cost adder in its Net Market Value (NMV) calculations and LCBF evaluations.

Because we direct utilities to continue to reply on the policy adopted in D.12-11-016 until integration costs are further reviewed by the Commission, we do not accept PG&E's proposal to require sellers, as part of specific contract negotiations, to bear all integration-related charges attributable to that resources output.[64] PG&E's proposal essentially results in a non-zero integration cost adder. The result proposed by PG&E is inconsistent with today's decision to continue the policy of a zero integration cost adder.

Accordingly, in the final 2013 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, SCE and PG&E are not authorized to include language that refers to the use of non-zero integration cost adders.

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[64] D.12-11-016 at 59-60.

4.6.2. Third-Party Resource Adequacy

In today's decision, the Commission again declines to adopt the proposal to permit a seller's offer of resource adequacy to be provided by a third-party (rather than by the seller's project). As the Commission stated in D.12-11-016, the record is currently insufficient to assess the risks and benefits of this proposal to ratepayers and to the resource adequacy market.[65]

CalWEA proposes that the Commission require the utilities to allow bids with third-party resource adequacy to more efficiently use the transmission system and meet resource adequacy requirements.[66] In response to this proposal, PG&E states that allowing substitution from an existing resource does not avoid long-term resource adequacy investment and, as a result, does not provide the same value to customers as the additional capacity from a new resource.[67]

CalWEA has not provided any additional information regarding the benefits, costs, and risks to ratepayers to persuade the Commission to take a different position from stated in D.12-11-016. Therefore, we decline to accept the third-party resource adequacy proposal because it is unclear what costs and benefits will result and how to quantify those costs and benefits.

4.6.3. Interconnection Status – New Solicitation Bid Requirement

This decision adopts the requirement that bids have the minimum of a completed CAISO Generation Interconnection and Deliverability Procedures

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65 D.12-11-016 at 59-60.

66 CalWEA July 12, 2013 comments at 10-11.

67 PG&E July 22, 2013 comments at 17.

(GIDAP) or CAISO Generation Interconnection Procedures (GIP) Phase II (or equivalent) [68] study to bid into a RPS solicitation.

Previously, in D.12-11-026, the Commission directed the utilities to require that projects have at minimum a completed CAISO GIP Phase I (or equivalent) study to be eligible to participate in its RPS solicitation.[69] PG&E's draft 2013 RPS Procurement Plan includes a requirement for projects to have completed a minimum Phase I transmission study.[70] SCE's and SDG&E's draft 2013 RPS Procurement Plans each include a requirement that at a minimum projects have a completed GIP Phase II Interconnection Study or Interconnection Facilities Study to be eligible to participate in their 2013 RPS solicitations.[71]

SCE states that the requirement will result in offers from projects that are further along in the development process and provide SCE with more complete transmission upgrade cost and timing information.[72]

No parties commented on these proposals.

We agree with SCE that requiring projects to have at minimum a completed Phase II transmission study provides more certainty regarding transmission costs and timing and is a reasonable approach to minimize project

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68 For projects that will be interconnecting on the distribution level: completed Fast Track or completed System Impact Study; for projects that will be interconnecting outside the CAISO's or the IOU's jurisdiction: equivalent interconnection progress.

69 D.12-11-016, *Decision Conditionally Accepting 2012 Renewables Portfolio Standard Procurement Plans*, Ordering Paragraph 11.

70 PG&E's 2013 Draft RPS Procurement Plan, Appendix 6, at 12.

71 SDG&E's 2013 Draft RPS Procurement Plan, Appendix 6.A, at 5 and SCE's 2013 Draft RPS Procurement Plan, Appendix F.1 at 2.

72 SCE's Amended 2013Draft RPS Procurement at 40.

failure risk. Therefore, we accept SCE's and SDG&E's Phase II (or equivalent) study minimum requirement. Further, we find it reasonable for all utilities to adopt this offer requirement.

Accordingly, in the final 2013 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, SCE and SDG&E are authorize to include in their RPS bid solicitation protocols a requirement for a CAISO GIDAP (or GIP) Phase II (or equivalent) study to bid into its 2013 RPS solicitation. PG&E shall modify its final 2013 RPS Procurement Plan to include the same requirement.

4.6.4. Shortlist Exclusivity

In today's decision, we find that the contract negotiating arrangement referred to as *shortlist exclusivity* will not be permitted based on the level of increased competition in the renewables market.

CalWEA recommends that the Commission revisit the use of shortlist exclusivity, which has been a standard component of the contract negotiation process since the Commission issued D.04-07-029.[73]

Shortlist exclusivity, as used here, refers to that point in time during the contract negotiation process when sellers (with projects on more than one utility's shortlist) are only permitted to negotiate with one potential buyer/utility. This arrangement could be described as the seller offering exclusive negotiating rights to the utility.[74] This arrangement was first

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[73] D.04-07-029, *Opinion Adopting Criteria for the Selection of Least-Cost and Best-Fit Renewable Resources* (July 8, 2004).

[74] CalWEA July 12, 2013 comments at 15.

addressed by the Commission in D.04-07-029.[75] At that time, we found that exclusivity was needed to prevent sellers from seeking increasingly higher prices from multiple utilities during the negotiation process since the renewable generation market was relatively small.[76]

In response to CalWEA's recommendation, the Independent Energy Producers' Association (IEP) states that shortlist exclusivity arrangements are no longer needed because RPS solicitations are highly competitive and, in addition, the utilities generally shortlist more resources than they intend to sign contracts.[77]

The utilities did not specifically comment on CalWEA's proposal.

Today, we modify, to the extent necessary, D.04-07-029 and find that utilities shall no longer require shortlist exclusivity as part of the shortlist and contract negotiation process because the RPS solicitation process is highly competitive and involves many potential sellers. As a result, there is less risk

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[75] D.04-07-029, *Opinion Adopting Criteria for the Selection of Least-Cost and Best-Fit Renewable Resources* (July 8, 2004).

[76] D.04-07-029, *Opinion Adopting Criteria for the Selection of Least-Cost and Best-Fit Renewable Resources* (July 8, 2004) at 8, stating: "For the 2004 RPS solicitation, the process we adopt is as follows. Bidders are permitted to submit bids into multiple solicitations. Bidders may bid whatever price they deem appropriate. After each utility notifies a bidder that it has been short-listed, the utility has the right to request that the bidder grant the utility exclusive negotiating rights for that project within a period no shorter than five days after the request. [new paragraph in original.] If the bidder refuses to grant exclusive negotiating rights, the utility is not required to continue negotiations with that bidder." The Commission also stated at conclusion of law 11 that "It is reasonable to require bidders that have been "short-listed" to withdraw competing bids, to avoid the situation in which the utilities are negotiating against one another for the same project, potentially resulting in inflated prices."

[77] IEP July 12, 2013 comments at 7.

that sellers will be in a position to obtain a higher price by simultaneously negotiating with more than one utility.

Accordingly, in the final 2013 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, PG&E, SCE, and SDG&E are not authorized to require shortlist exclusivity as part of the contract negotiating process.

4.7. Proposals to Change Terms in the Pro Forma Contracts

Pro forma contracts were included as part of PG&E's, SCE's, and SDG&E's draft 2013 bid solicitation protocols dated June 28, 2013. The pro forma contracts serve as the starting point for negotiating a final agreement between a seller and utility.[78] The negotiable terms and conditions of the pro forma contracts differ from, for example, the so-called standard contracts in the § 399.20 Feed-in-Tariff[79] and Renewable Auction Mechanism programs (also known as RAM).[80] In these programs, the contracts are non-negotiable and, instead, the terms are pre-approved by the Commission with the goal of creating a more expedited contracting process.

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[78] All terms and conditions in the pro forma contract are negotiable except for the "standard terms and conditions," as set forth in D.08-04-009, D.08-08-028, and D.10-03-021, as modified by D.11-01-025.

[79] D.12-05-034, *Decision Adopting Joint standard Contract for Section 399.20 Feed-In Tariff Program and Granting, in Part, Petitions for Modification of Decision 12-05-035*; D.13-01-041, *Order Modifying Decision (D.) 12-05-035 and Denying Rehearing of Decision, as Modified*; D.12-05-035, *Decision Revising Feed-in Tariff Program, Implementing Amendments to Public Utilities Code Section 399.20 Enacted by Senate Bill 380, Senate Bill 32 and Senate Bill 2 1X* and *Denying Petitions for Modification*.

[80] RAM program was created by the Commission in D.10-12-048.

While we consider some of the issues raised by parties with regards to the utilities' proposed modifications to pro forma contracts, the Commission prefers, in most instances, that the parties negotiate contract terms. The Commission will review the resulting executed contracts in their totality upon submission to the Commission for approval. Such review includes whether the terms of the pro forma contracts are consistent with Commission decisions, cost reasonableness, and fair allocation of risk to the seller, buyer, and ratepayer.

4.7.1. Time-of-Delivery Factors

In this decision, we accept the requests by PG&E, SCE, and SDG&E to update their Time-of-Delivery (TOD) factors and the TOD period definitions for the 2013 solicitation. We also accept SDG&E's proposal to rely on four sets of TOD factors, rather than two sets.

TOD factors are applied to contract prices to reflect the higher value of generation supplied during the on-peak hours and the lower value of generation supplied during the off-peak hours. In their 2013 draft RPS Plans, the utilities suggest modifications to their existing TOD factors and TOD period definitions to reflect updated forward energy, resource adequacy price curves, and increases in on-peak generation.[81] Also, SDG&E adds two more sets of TOD factors to further differentiate between certain projects.[82]

TOD factors are applied both in the LCBF evaluation process as well as to contract prices to determine the revenues that a seller will receive for its product.

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[81] PG&E's Draft 2013 RPS Procurement Plan at 90; SCE's Amended Draft 2013 RPS Procurement Plan at 50, SDG&E's RPS Procurement Plan at 39.

[82] SDG&E's four sets of TOD factors are: local, Imperial Valley, system, and energy-only (SDG&E's Draft 2013 RPS Procurement Plan, Appendix 6-A at 5).

In D.05-12-042, we adopted a recommendation to approve utilities' TOD factors during the review of utilities' RPS Procurement Plans.[83] We also have previously authorized PG&E, SCE, and SDG&E to develop their own TOD factors.[84]

In response to the proposed 2013 TOD factors, the Large-Scale Solar Association (LSA) suggests the Commission review the TOD factors as part of LCBF.[85] IEP raises a concern regarding the appropriateness of modifying TOD factors based on the evidentiary record in this proceeding.[86]

We have previously examined the reasonableness of TOD factors generally.[87] We have found previously that each utility may develop its own TOD factors to best reflect each utility's market-based valuation of electricity and capacity in different time periods.[88] Similar to these prior Commission findings, today we conclude that the utilities' approach and the recommended new TOD factors and TOD period definitions are reasonable, even if different than those applied in 2012 or previous years.

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[83] D.05-12-042 *Interim Opinion Adopting Methodology for 2005 Market Price Referent* (December 15, 2005) at 21-22.

[84] D.12-11-016 at 36-39; D.05-12-042, *Interim Opinion Adopting Methodology for 2005 Market Price Referent* (December 15, 2005) at 53.

[85] LSA July 12, 2013 comments at 10.

[86] IEP July 12, 2013 comments at 2.

[87] D.09-06-018, *Decision Conditionally Accepting Procurement Plans for 2009 Renewables Portfolio Standard Solicitations and Integrated Resource Plan Supplements* at 46 and D.06-05-039 *Opinion Conditionally Approving Procurement Plans for 2006 RPS Solicitations, Addressing TOD Benchmarking Methodology and Closing Proceeding* at 68; D.05-12-042, *Interim Opinion Adopting Methodology for 2005 Market Price Referent* (December 15, 2005) at 21-22.

[88] D.06-05-039, *Opinion Conditionally Approving Procurement Plans for 2006 RPS Solicitations, Addressing TOD Benchmarking Methodology and Closing Proceeding* at 68.

However, as we stated in D.12-11-016 and in an effort to respond to concerns expressed by LSA and IEP, we continue to be receptive to examining the methodologies used to derive the TOD factors in a subsequent part of this proceeding.

Accordingly, in the final 2013 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, PG&E and SCE are authorized to use in their 2013 RPS solicitation two sets of TOD factors to reflect energy-only and fully deliverable status. SDG&E is authorized to use four sets of TOD factors to reflect energy-only and fully deliverable status, as well as varying attributes. Changes to the TOD periods are also authorized. This authorization only applies to the 2013 RPS solicitation.

4.7.2. Energy in Excess of Seller's Delivery Profile

This decision accepts PG&E's, SCE's, and SDG&E's proposal to incorporate into the pro forma contracts a term to require sellers to accept a lower price (or no price) if deliveries fail to conform to seller's delivery profile (within a designated margin of error) because this term, together with other contract terms, are designed to provide the utilities with a reasonable level of control over managing their energy supply and expected contract costs. All three utilities may incorporate this term into their pro forma contracts.

SCE and SDG&E propose to reduce the price paid to zero for delivered energy during a given Settlement Interval that exceeds 110% of the energy originally expected. Further, PG&E, SCE and SDG&E propose that if the seller delivers more than 115% of annual expected annual net energy production within a year, then the seller is paid 75% of the contract price for any deliveries above the 115% amount.[89] Additionally, SDG&E proposes that if the seller delivers more than 115% of expected energy production for a given TOD period, then the seller is paid 75% of the contract price for any deliveries above the 115% amount.

SCE states that the provisions ensure that the seller does not install capacity in excess of the specified contract capacity.[90] SDG&E explains that these provisions serve to mitigate the risk of increased ratepayer cost due to a seller submitting one delivery profile but delivering energy per a different profile. CalWEA recommends rejecting SDG&E's excess delivered energy by TOD period provisions because wind generation has a delivery profile that is predictable over several years and less predictable at a given hour or day.[91] CalWEA further suggests that SDG&E's request for a generation amount per TOD period serves to penalize wind generated power.

We find that the proposed requirements for expected generation by hour, TOD periods, and by year are sufficiently flexible to accommodate the profile of wind generation. We also find that a delivery profile from sellers provides a reasonable means for utilities to manage energy supply and costs, including the terms related to reduced energy price for energy in excess of seller's expected generation.

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[89] SCE 2013 Amended Draft RPS Procurement Plan, pro forma contract at sec. 1.06(c) and SDG&E 2013 Draft RPS Procurement Plan, pro forma contract at sec. 4.2(a)(iii).

[90] SCE 2013 Amended Draft RPS Procurement Plan at 52.

[91] CalWEA July 12, 2013 comments at 21.

Accordingly, in the final 2013 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, PG&E , SCE, and SDG&E are authorized to require sellers to deliver generation that meets an expected delivery profile and to pay sellers a lower price (or no price) if sellers are not able to deliver within certain parameters.

4.7.3. Buyer Curtailment and Seller Compensation for Loss of Production Tax Credits due to Curtailment

In this decision, we reject PG&E's pro forma contract modification to require unlimited buyer curtailment and accept the minor modifications to SCE's buyer curtailment provisions. We also clarify that the utilities are not required to compensate sellers for the loss of production tax credits due to curtailment.

In PG&E's draft 2013 RPS Procurement Plan, PG&E includes an updated pro forma contract as part of its proposed 2013 solicitation protocol. Among the terms that PG&E has modified are provisions regarding buyer curtailment. PG&E proposes that it be permitted to curtail a buyer on an unlimited basis to provide PG&E with greater control over the output of resources, reduce overall ratepayer costs, and eliminate negative pricing.[92]

SCE also proposes revisions to its pro forma contract such that buyer curtailment will no longer be in relation to the day-ahead and real-time markets and, instead, SCE sets a limited amount of uncompensated hours and will pay for any hours curtailed during on-peak hours.[93] We find these changes will not negatively impact the ability of buyers to obtain financing.

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[92] PG&E Draft 2013 RPS Procurement Plan at 80 and 89.

[93] SCE Amended Draft 2013 RPS Procurement Plan at 48-49.

SDG&E makes no modifications to its buyer curtailment terms which are limited to five percent of expected annual generation.[94]

Parties object to PG&E's modifications noting that the value of curtailment is not clear to the market, no renewable energy credits will be created if the renewable generation is curtailed, and that it is highly unlikely that PG&E will actually need to curtail a generator 8,760 hours per year.[95]

We agree with parties that it is highly unlikely that PG&E will actually need to curtail a generator 8,760 hours per year. Additionally, it is unreasonable for ratepayers to be responsible for all the risk and for the costs of a contract executed for the purposes receiving RPS-eligible generation and associated RECs only to have the potential that it will never actually receive any renewable energy credits pursuant to the contract. Nevertheless, we recognize the possibility that buyer curtailment in the RPS context may create additional operational flexibility.

Therefore, in this decision, we direct PG&E to remove the unlimited buyer curtailment provisions in its pro forma contract and in any related materials. PG&E may submit a revised curtailment provision with its final 2013 RPS Procurement Plan. Additionally, while we accept SCE's buyer curtailment provisions, we only accept their approaches for the 2013 solicitation because buyer curtailment is still an evolving issue and we anticipate reviewing this matter and other renewables integration issues, such as, congestion and

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94 SDG&E Draft 2013 RPS Procurement Plan, pro forma contract, sec. 3.4.

95 IEP July 12, 2013 comments at 4; LSA July 12, 2013 comments at 6.

operational flexibility, further in this proceeding when we review LCBF. SDG&E offered no revisions to curtailment provisions.

In addition, the Commission has previously addressed whether utilities should be required to compensate sellers for lost production tax credits due to buyer curtailment. In D.11-04-030, the Commission did not require or disallow compensation for lost production tax credits. Nothing presented by parties persuades us to modify the Commission's previous position.[96] Therefore, PG&E's, SCE's, and SDG&E's approach towards lost production tax credits due to buyer curtailment are accepted.

Accordingly, in the final 2013 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, PG&E is not authorized to include a pro forma contract provision that requires buyer to agree to unlimited curtailment. The minor revisions proposed by SCE to the curtailment provisions are accepted. SDG&E offered no revisions to curtailment provisions.

4.8. 2013 RPS Procurement Plans - Solicitation Bid Requirements

The utilities were directed in the May 10, 2013 ACR, pursuant to § 399.13(a)(5)(C), to include bid solicitation protocols that specify what quantity of products are being requested, deliverability characteristics, required online dates, term lengths, and locational preferences. The utilities request various modifications to their 2013 solicitation protocols as compared to their 2012 solicitation protocols. These proposals are addressed below.

[96] CalWEA July 12, 2013 comments at 4 and IEP July 12, 2013 comments at 4.

4.8.1. Solicitation Preferences for Specific RPS Resources

In today's decision, and similar to the outcome in D.12-11-016,[97] we accept the proposals by PG&E, SCE, and SDG&E to include the varying preferences set forth in their 2013 draft RPS Procurement Plans, such as project location, delivery start dates, term lengths, and specific portfolio content categories in the 2013 bid solicitation protocols.

In evaluating preferences, we seek to balance providing the utilities with a reasonable amount of discretion in establishing the parameters of their solicitations with obtaining the most favorable outcomes in the solicitations by not unduly restricting participation by otherwise beneficial projects. The Utility Reform Network (TURN) raises a concern that some preferences might disqualify bids that are otherwise cost efficient.[98] For example, it is unclear whether PG&E's preference for new resources with contract start dates in 2020 or later, could unduly restrict the participation of cost efficient projects with slightly different start dates. That said, we do not require any modifications to PG&E's preferences today because we appreciate the need for utilities to solicit contracts that conform to their procurement needs.[99]

Accordingly, in the final 2013 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, PG&E, SCE, and SDG&E are authorized to include varying preferences.

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[97] D.12-11-016, Ordering Paragraph 5 at 89.

[98] TURN July 12, 2013 comments at 2 and 7.

[99] PG&E Draft 2013 RPS Procurement Plan at 19.

4.8.2. Solicitation Preferences for Minimum Project Size

This decision retains the existing limitations, as confirmed in D.12-11-016, on the minimum size of projects eligible for participation in the RPS Program of 1.5 MW because we envision the RPS Program as a program with broad eligibility.[100] However, we permit the utilities to rely on preferences for project sizes for their solicitations.

PG&E's, SCE's, and SDG&E's draft 2013 RPS Procurement Plans each include preferences for the minimum nameplate capacity size of a project eligible to participate in an RPS solicitation. Previously, the Commission directed these utilities to set the minimum capacity for projects bidding into the RPS Program's solicitation at 1.5 MW based on then available contracting options for smaller projects under the Feed-in-Tariff program.[101] Utilities are permitted, however, to designate preferences that fall above the minimum size.

Accordingly, consistent with D.12-11-016 and because we continue to envision the RPS Program as a program with broad project eligibility, we adopt no changes to the existing size limitation of 1.5 MW but preferences are permitted above the minimum project size.

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[100] D.12-11-016 at 44.

[101] D.08-02-008, *Opinion Conditionally Accepting Procurement Plans for 2008 RPS Solicitations* (February 2, 2008) at 31.

5. PG&E's 2013 RPS Procurement Plan

5.1. Additional Procurement for "Adequate" Bank

In this decision, we accept PG&E's general solicitation goals but reject PG&E's proposal for additional procurement for "adequate" bank.

In PG&E's draft 2013 RPS Procurement Plan, PG&E states its goal is to procure up to 1,500 GWh per year of RPS-eligible deliveries plus additional procurement from the Renewable Auction Mechanism, Feed-in Tariff, Combined Heat and Power/Qualifying Facility and Photovoltaic programs. PG&E also states its separate goal to procure Portfolio Content Category 2 and 3 RPS products[102] to build and maintain an "adequate" bank.[103] The meaning of the term "adequate," as used by PG&E, is unclear.

PG&E states that an "adequate" bank is needed to mitigate risks with short-term variability in load, to protect against project failure or delay exceeding forecasts, and to eliminate the need at this time to intentionally procure long-term contracts above the 33% target by utilizing the bank to manage the year-to-year variability from performing RPS resources.[104]

DRA objects to PG&E's proposed level of "adequate" banked procurement on the basis that it is not cost-effective or necessary for ratepayers and is based on an incomplete analysis.[105]

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[102] PG&E's reference to Portfolio Content Category 2 and 3 RPS products refers to products defined in Ordering Paragraph 2 and 3 of D.11-12-052, respectively.

[103] PG&E's Draft 2013 RPS Procurement Plan, June 28, 2013 at 84.

[104] PG&E's Draft 2013 RPS Procurement Plan, June 28, 2013 at 83.

[105] DRA comments, July 12, 2013 at 5.

We find that, given the lack of quantitative analysis by PG&E, the absence of a clear procurement goal for this additional procurement, and because the forecasted amount of bank that PG&E expects to accumulate from Compliance Period 2014-2016 and Compliance Period 2017-2020 appears substantial, it is not reasonable at this time to accept PG&E's proposal to procure RECs beyond its stated 1,500 GWh solicitation goal plus procurement from other smaller Commission-authorized programs.[106] Should PG&E provide a more robust quantitative analysis and supporting data to explain its calculation based on the quantities needed to address identified risks, such as, procurement strategy for determined need and clear procurement goals, we may revisit its request for "adequate" bank in a future solicitation.

Accordingly, in the final 2013 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, PG&E is not authorized to include procurement for Portfolio Content Category 2 and 3 RPS products to build and maintain an "adequate" bank.

5.2. Ranking Bids Using Portfolio-Adjusted Value Methodology

In this decision, we accept PG&E's request to include its Portfolio-Adjusted Value (PAV) methodology in its solicitation protocol for its 2013 solicitation with one modification. We direct PG&E to remove the "contract term length" adjustment from its PAV methodology because PG&E did not

[106] PG&E forecasts 16,865 GWh of bank for Compliance Period 2014-2016 and it increases to 17,783 GWh after Compliance Period 2017-2020 (PG&E's Draft 2013 RPS Procurement Plan, Appendix 1A, June 28, 2013.)

demonstrate the representative cost to PG&E and its ratepayers represented by the "contract term length" adjustment.

In PG&E's draft 2013 RPS Procurement Plan, PG&E states that it plans to adjust a bid's NMV based on the offer's contract term length.[107] Specifically, PG&E proposes to include an adder in its offer evaluation methodology to quantify its preference for shorter contract term lengths such that shorter term offers would receive a larger adder than longer term offers. Parties object to PG&E's proposed methodology on the grounds that it arbitrarily skews bid rankings, the approach could be counterproductive to ratepayer interests, and that the impact to bid rankings has not been demonstrated as a cost to PG&E and its ratepayers.[108]

We agree with the parties' objections that PG&E's contract term length adjustment has not been reasonably justified because PG&E has not demonstrated the cost to PG&E and its ratepayers that the term length adder is proposed to represent.

Accordingly, in the final 2013 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, the use of the PG&E's PAV methodology, as modified to exclude the contract term length adjustment, is accepted for only the 2013 solicitation because the Commission anticipates reviewing this matter and other aspects of PG&E's PAV methodology further in this proceeding when the Commission reviews LCBF.

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[107] PG&E 2012 Renewable Energy Procurement Plan, 2012 Solicitation Protocol, Attachment K, May 23, 2012 at 7.

[108] TURN July 12, 2013 comments at 7; CalWEA July 22, 2013 reply comments at 4.

5.3. Allocation of All Integration Costs to Sellers

In this decision at section 4.6.1, we decline to accept PG&E's integration cost adder for use in the LCBF evaluations. Consistent with this finding, we do not accept PG&E's proposal to include a term in its pro forma contract that sellers bear all integration-related charges attributable to the resource's output.

In PG&E's draft 2013 RPS Procurement Plan, PG&E states that "If the Commission does not adopt a reasonable integration cost adder for use in the evaluation of the 2013 RPS solicitation bids, PG&E intends to require sellers as part of specific contract negotiations to bear all integration-related charges that are attributable to the resource's output."[109] PG&E did not identify any of the specific charges that may be integration-related.

Some parties object to PG&E's proposal stating that the proposal contradicts the Commission's order to not include integration costs, that no agreed-upon basis to quantify or allocate integration costs exists, and that the costs are not predictable.[110]

We agree with parties that PG&E's proposed contract provision is inconsistent with the Commission's current orders to use a non-zero integration cost adder and is not currently supported by the record in this proceeding. We direct PG&E to remove any requirements that sellers are responsible for all integration costs that attributable to a resource's output. We anticipate that as integration costs of resources will be identified, defined, and quantified the Commission may or may not determine that it is appropriate to allocate some of

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[109] PG&E Draft 2013 RPS Procurement Plan at 92.

[110] CalWEA July 12, 2013 comments at 6 and LSA July 12, 2013 comments at 5.

the integration costs to sellers and the use of a non-zero integration cost adder for use in LCBF evaluations.

Accordingly, in the final 2013 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, PG&E is not authorized to include a provision that requires the seller to bear all integration-related charges that are attributable to the seller's resource.

5.4. Project Development Security

In this decision, we do not accept PG&E's proposed amount for its project development security. We direct PG&E to modify its project development security requirement in its proposed pro forma contract and related materials to an amount which is more aligned with the other utilities.

In PG&E's draft 2013 RPS Procurement Plan, PG&E requires a $300/kilowatt (kW) project development security for contracts executed with Portfolio Content Category 1 and 2 products.[111] PG&E states that this amount provides greater incentives for the timely delivery of power under the terms of executed contracts and will result in more highly-viable projects with experienced counterparties.[112] Parties object to the amount asserting that it is excessive, unnecessary, and wasteful in addition to noting that it is significantly higher than SCE's and SDG&E's development requirements.[113]

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[111] PG&E Draft 2013 RPS Procurement Plan, Appendix 6, 2013 RPS Solicitation Protocol at 30.

[112] PG&E Draft 2013 RPS Procurement Plan at 50; PG&E July 22, 2013 reply comments at 12.

[113] LSA July 12, 2013 comments at 8; IEP July 12, 2013 comments at 7. SCE's project development security is $90/kW for baseload resources and $60/kW for intermittent resources. SCE's Amended Draft 2013 RPS Procurement Plan, Volume 2, pro forma

Footnote continued on next page

While the Commission did not specifically address PG&E's increased development security amount last year in D.12-11-016, we agree with parties now that it is worth reviewing the reasonableness of PG&E's significantly higher requirement than SCE and SDG&E.

Given that the utilities are facing essentially the same project viability risks because a seller could contract with any of the utilities and because a number of other screens exist to measure and increase project viability (project viability calculator and minimum CAISO Phase II interconnection study, or equivalent), PG&E's rationale does not justify the substantial gap in amount required between PG&E and the other two utilities.

Accordingly, in the final 2013 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, PG&E shall modify its 2013 RPS solicitation protocol and other parts of its 2013 draft RPS Procurement Plan, as necessary, to include a project development security equivalent to SCE's $90/kW for baseload resources and $60/kW for intermittent resources for Portfolio Content Category 1 and 2 products.

5.5. Motion for Confidentiality – Denied, in Part

In this decision, we deny, in part, PG&E's request for confidential treatment of its RPS "cost quantification" information in its 2013 draft RPS Procurement Plans and direct PG&E to resubmit this information on a non-confidential basis in conformance with this decision. In all other respects,

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contract at sec. 3.06(a). SDG&E's project development security is $10/MWh times the expected annual generation. SDG&E's Draft 2013 RPS Procurement Plan, 2013 Request for Offers, August 28, 2013 at 29.

PG&E's request for confidential treatment of the information in its 2013 draft RPS Procurement Plan is granted.

The May 10, 2013 ACR directed PG&E, SCE, SDG&E, Bear Valley Electric Service, and Liberty Utilities LLC to provide specific aggregated RPS program "cost quantification" information.[114] Importantly, the May 10, 2013 ACR stated that responses by utilities should be non-confidential to the greatest extent possible and that the information could also be used to inform the Commission's development of a cost containment mechanism, pursuant to §§ 399.15(c)-(h), which the Commission is considering presently in this proceeding.

PG&E filed RPS cost quantification information in both its June 28, 2013 draft 2013 RPS Procurement Plan and its August 28, 2013 update its draft 2013 RPS Procurement Plan. PG&E also filed a motion seeking confidential treatment of portions of its RPS cost quantification, among other information, pursuant to the Commission's confidentiality rules set forth in D.06-06-066 and D.08-04-023.[115]

We deny, in part, PG&E's motion for confidential treatment of its RPS cost quantification information because we find that making this aggregated RPS cost data public will not harm PG&E or its ratepayers. We further find that public disclosure of this information is consistent with Commission decisions and the intent of the Legislature to promote greater transparency regarding California ratepayer expenditures to support the state's RPS Program.

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[114] May 10, 2013 ACR at 18-19.

[115] D.06-06-066, *Interim Opinion Implementing Senate Bill No. 1488, Relating to Confidentiality of Electric Procurement Data Submitted to the Commission* (July 5, 2006) and

Footnote continued on next page

The aggregated RPS cost data provided by PG&E reveals actual and forecasted RPS expenditures by resource type and in total amounts, and, consequently, is not market sensitive data. Disclosing the aggregated expenditures data will not harm PG&E or its ratepayers. Our finding is supported by the fact that SCE and SDG&E provide this data on a non-confidential basis.

Moreover, in D.06-06-066, as modified by D.07-05-032, the Commission determined that "RPS information should be public to a greater extent than non-RPS data."[116] This finding is consistent with recent actions by the Legislature, most notably, SB 836 (Padilla, Stat. 2011, ch. 600, § 1), which requires the Commission to report annually to the Legislature on past RPS expenditures and the cost of recent RPS contract prices. The provision of the aggregated RPS cost reporting on a non-confidential basis is a reasonable extension of the Commission's efforts to provide public information on the RPS Program and to comply with the Legislative reporting requirements.

Accordingly, in the final RPS Procurement Plan to be filed with the Commission pursuant to the schedule adopted herein, PG&E shall make public specific information redacted in its draft 2013 RPS Procurement Plan, unless doing so would reveal a single RPS contract price that would otherwise be covered by D.06-06-066 and D.08-04-023. Specifically, the information to be made public is cited on the following pages:

D.08-04-023, *Decision Adopting Model Protective Order and Non-Disclosure Agreement, Resolving Petition for Modification and Ratifying.* (April 10, 2008).

[116] D.07-05-032, *Order Modifying Decision and denying Rehearing of Decision as Modified*. (May 3, 2007) at 64.

- Page 102
- Page 109, Table 12-1, rows 1,2, 5 and row 8 for 2017 and beyond
- Page 110, Table 12-1, rows 1,2, 5 and 8
- Appendix 2, Table 1, rows 11, 12 and 14
- Appendix 2, Table 2, rows 2, 3, 6, 11, 12, 14 (for 2017 and beyond), 16-26, 28-29 (for 2017 and beyond)

6. SCE's 2013 RPS Procurement Plan

6.1. LCBF Congestion Cost Adder for Energy-Only Projects

In this decision, we accept SCE's proposed LCBF methodology, including the congestion cost adders for energy-only project for its 2013 RPS solicitation. We continue to require utilities to accept energy-only bids.[117]

SCE's draft 2013 RPS Procurement Plan proposes a change to its LCBF methodology by applying congestion cost adders to energy-only offers, but not to FCDS offers.[118] SCE's proposed modification is one of a number of changes that SCE proposes to address the risk that sufficient transmission capacity may not be available to deliver a project's generation at all times, and, as a result, cause congestion and negative market prices. Specifically, SCE states that by energy-only projects not funding Delivery Network Upgrades, these projects increase the risk of congestion and negative pricing.

LSA acknowledges that problems exist with current practice of precluding full capacity deliverability service (FCDS) projects from having either operating priority or transmission rights under the CAISO's tariff, but LSA asserts that

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117 D.11-04-030 at 21.

SCE's approach is not the best solution to address the problem and that the approach is likely to discourage energy-only projects.[119] LSA states that SCE's proposal may discourage energy-only projects. LSA further states that SCE's proposal relies on a different application of congestion cost adders than expressed in D.11-04-030.

We agree that D.11-04-030 did not address SCE's proposed use of congestion cost adders. In D.11-04-030, the Commission found that it was not clear that the cost to build additional facilities (e.g., transmission for deliverability) will be lower than costs related to congestion and curtailment and adopted the requirement of congestion cost adders in LCBF evaluations. According to D.11-04-030, the purpose for incorporating congestion cost adders in LCBF evaluations was to, regardless of whether a developer intended to pursue an energy-only or full capacity deliverability service resources interconnection, encourage all developers to seek project sites with fewer potential congestion costs and to assess congestion costs as part of a project's value.[120] In contrast, SCE now proposes to use congestion cost adders to differentiate between the value provided by energy-only projects and FCDS projects.

We find that it is still unclear if the additional transmission costs would be lower than costs associated with negative market pricing caused by increased congestion, but we accept SCE's approach of applying congestion cost adders to

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118 SCE Amended Draft 2013 RPS Procurement Plan, Volume 2, Appendix H-1, August 28, 2013 at 6.

119 LSA July 12, 2013 comments at 7-8.

120 D.11-04-030 at 22.

energy-only project offers for the purposes of valuing offers only for its 2013 RPS solicitation because the Commission has previously found that energy-only interconnections may increase congestion risk.[121] Our approval is limited to the 2013 solicitation, and we expect Energy Division to monitor the impacts of SCE change in LCBF methodology and anticipate that this issue will be further examined in this proceeding when we review LCBF.

Accordingly, in the final 2013 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, SCE is permitted, for only the 2013 solicitation, to incorporate a congestion cost adder into its LCBF methodology for energy-only projects.

6.2. Energy-Only Sellers Responsible for Any Negative Prices

In this decision, we do not accept SCE's proposed change to its pro forma contract for its 2013 RPS solicitation to require sellers to bear the risks of negative pricing.

SCE proposes to modify its pro forma contract to require sellers with projects interconnected to the transmission system as energy-only to bear the risk that market prices will be negative but, at the same time, SCE proposes to not issue curtailments to the energy-only facility except as directed by the CAISO, the transmission provider, or to respond to an emergency.[122]

SCE states that sellers of generation from energy-only resources should bear this risk that market prices will be negative because they do not contribute to ensuring that sufficient transmission capacity is available by not funding any

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[121] D.11-04-030, Finding of Fact 7.

[122] SCE Amended Draft 2013 RPS Procurement Plan at 50.

Deliverability Network Upgrades.[123] CalWEA states that SCE overstates the risk and SCE's proposed requirement exposes the seller to unquantifiable and unmanageable revenue risk that could affect the financeability of the contracts.[124]

Based on the absence of sufficient record development on this topic, we find SCE's proposed pro forma contract modification is unreasonable at this time.

Accordingly, in the final 2013 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, SCE is not authorized to include changes to its proposed 2013 RPS pro forma contract related to sellers bearing the risks of negative pricing for energy-only projects.

7. PacifiCorp

In this decision, we direct PacifiCorp to file additional information on its planned unbundled REC solicitation.

PacifiCorp filed its 2013 Integrated Resource Plan on April 30, 2013. In this filing, PacifiCorp states its plan for providing reliable, reasonably cost service with manageable risks to its customers. PacifiCorp identifies the following as the key elements of its 2013 Integrated Resource Plan: (1) a finding of resource need for 2013-2022; (2) the preferred portfolio of incremental supply-side and demand-side resources to meet this need; and (3) an action plan identifying the steps that PacifiCorp will take during the next two to four years to implement the plan.[125]

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[123] SCE July 22, 2013 reply comments at 6.

[124] CalWEA July 12, 2013 comments at 12.

[125] PacifiCorp's 2013 Integrated Resource Plan, Vol. I at 1.

With respect to meeting its RPS Program requirements, PacifiCorp states that it will issue, at least annually, requests for proposals seeking then current-year or forward-year vintage unbundled RECs. On May 30, 2013, in addition to a 2013 Integrated Resource Plan, PacifiCorp filed an On-Year Supplement in response to the May 10, 2013 ACR.

Generally, we find the Integrated Resource Plan and On-Year Supplement consistent with Commission requirements and with the May 10, 2013 ACR but one deficiency exists. The Integrated Resource Plan and On-Year Supplement should include information regarding the solicitation for unbundled RECs. PacifiCorp filings do not include this information. Pursuant to D.08-05-029, PacifiCorp is required to provide information about the solicitation, including a pro forma contract if it "intends to undertake a competitive solicitation solely for California RPS purposes in any year."[126]

Accordingly, on or before 14 days from the date that this decision is mailed, PacifiCorp shall file an amended On-Year Supplement that includes information regarding its planned unbundled REC solicitation, including a pro forma contract.

8. Bear Valley Electric Service

Bear Valley Electric Service requests additional modifications to the procurement planning process to exempt it from the annual RPS Procurement Plans filing requirement until such time as material changes occur to its 2013 Plan.[127] While we support Bear Valley Electric Service's efforts to reduce the

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[126] D.08-05-029 at 24.

[127] Bear Valley Electric Service July 12, 2013 comments.

administrative burden related to the RPS Procurement Plans, Bear Valley did not provide a sufficient showing that its request is consistent with statutory law.[128] Bear Valley Electric Service's request is denied.

9. Changes to the Annual Procurement Plan Cycle

In this decision, we do not adopt the proposal presented in the May 10, 2013 ACR to rely on a two-year procurement plan cycle. However, we adopt a minor modification to the review and approval process to promote regulatory and administrative efficiencies.

In the May 10, 2013 ACR, parties were asked to comment on a proposal to authorize utilities to procure RPS-eligible resources over a two-year planning horizon. The proposal would apply to all retail sellers. Under the May 10, 2013 ACR's proposal, a full procurement plan would be required once every two years and a Tier 2 advice letter would be required in the off-years to address whether the retail seller intended to conduct a solicitation (with support for the decision including updated portfolio assessment and updated solicitation material, if appropriate).[129] Utilities would be required to hold solicitations simultaneously. Consistent with past years, the intent of this proposal was to streamline the procurement process without sacrificing the transparency provided by the filing of annual procurement plans.

[128] Bear Valley Electric Service July 12, 2013 comments; See, e.g., 399.18 and 399.13(a)(1).

[129] The May 10, 2013 proposal is very similar to the proposal presented last year in an ACR dated April 5, 2012. The main difference is the proposal this year to rely on a Tier 2 advice letter while the proposal last year suggested relying on a Tier 3 advice letter for the off-year filings.

Parties generally support this proposal to the extent that the Commission sought to streamline RPS procurement. However, parties also indicate a two-year procurement cycle, even with supplemental filings in the off-years, may be inconsistent with the statutory requirement for "annual" RPS procurement plans. Parties also indicate that, if the annual filings are replaced by multi-year filings reviewed by under the informal advice letter process, the RPS procurement review process may become less transparent. In addition, parties indicate that the proposed Tier 2 advice letter process could result in an equally burdensome review process which would offer no efficiencies over a full RPS Procurement Plan. As result, parties claim that the benefits, if any, of moving to a two-year procurement cycle are unclear.

We agree that, at this point in time, the current proposal for a two-year procurement plan cycle fails to present definite advantages. We concluded similarly in D.12-11-016. We do, however, incorporate some additional flexibility into the processes relied upon by the Commission to review the RPS Procurement Plans to promote regulatory and administrative efficiencies. The following change is adopted:

> The annual procurement plan cycle will be initiated by either an Assigned Commissioner's ruling, consistent with the current practice, or an ALJ ruling.

The use of a concise ALJ ruling will provide the Commission with a more streamlined way of initiating the process and could promote regulatory and administrative efficiencies. We continue to review the references to "annual approval of the plans" in the statute. We also continue to be interested in ways to streamline the RPS procurement process while maintaining the transparency of the program. We encourage parties to present suggestions to the Commission at appropriate times. These suggestions should address statutory constraints.

10. Adopted Schedule for 2013 RPS Bid Solicitations

Today, the Commission adopts a schedule that reflects its experience with the 2012 solicitation, as set forth in D.12-11-016, and prior solicitations. The adopted schedule provides utilities and Energy Division Staff reasonable flexibility for contracts resulting from the solicitation. The utilities all propose similar schedules for the 2013 RPS bid solicitations.[130]

The utilities' proposals include a date after which a utility may request an exclusivity agreement, referred to as *shortlist exclusivity*, from a bidder before continuing negotiations. At section 4.6.4, we modify the practice of *shortlist exclusivity*. Therefore, we longer include dates relevant to entering into exclusivity agreements in the below schedule.

In addition, some parties request the Commission to compress the 2013 solicitation schedule in an effort to accommodate deadlines for qualifying for the full advantages of the Investment Tax Credit.[131] We support this goal and, as a result, eliminated approximately 34 days from the length of the prior year's schedule between the issuing of RFOs and submission of shortlist.

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[130] SDG&E did not propose a schedule in its Draft 2013 RPS Procurement Plan. LSA recommends a schedule at LSA July 12, 2013 comments at 11.

[131] The Investment Tax Credit is a federal tax credit for eligible renewable and other technologies 26 U.S.C. § 48. NextEra July 12, 2013 comments at 10, stating that the Investment Tax Credit starts to decrease after December 31, 2016. LSA September 11, 2013 comments at 5.

Lastly, similar to requests in prior years by the utilities, PG&E suggests the utilities be permitted to schedule solicitations on dates consistent with a particular utilities' overall procurement strategy and that the Commission should not continue to require simultaneous solicitations for the three utilities.[132]

We refrain from changing the simultaneous solicitation rule. While we see merit in permitting utilities to create their own solicitations schedules, differing schedules for the annual filing requirements pose challenges for the Commission because staff would be tracking several different solicitation schedules simultaneously and, as a result, have to manage and review a significant amount of information submitted by the utilities on different timelines.

Consistent with prior years, the Commission authorizes the Energy Division Director, with notice to utilities and parties, to change the schedule as appropriate or as necessary for efficient administration of the 2013 RPS solicitation process. Parties may also seek schedule modification by letter to the Executive Director consistent with Rule 16.6 of the Commission's Rules of Practice and Procedure. To provide added flexibility to the schedule, this year we permit all solicitation dates included in the final RPS Procurement Plans to be adjusted by the utilities without prior Commission approval with the exception of the below noted dates.

Schedule for 2013 Solicitation

[132] PG&E July 12, 2013 comments at 4.

Line No.	Item	No. of Days (cumulative)
1	Mailing of Commission decision conditionally accepting 2012 RPS Procurement Plans	0
2	PG&E, SCE and SDG&E file final 2013 RPS Procurement Plans	14
3	PG&E, SCE, and SDG&E issue RFOs (unless amended Plans are suspended by Energy Division Director by Day 24)*	24
4	PG&E, SCE, and SDG&E submit shortlists to Commission and Procurement Review Group	120
5	PG&E, SCE, and SDG&E file by Tier 2 advice letter (a) Evaluation Criteria and Selection Process Report and (b) Independent Evaluator's Report	150
6	PG&E, SCE and SDG&E 2013 RPS RFO Shortlists Expire	485
7	PG&E, SCE, and SDG&E submit Advice Letters with contracts/power purchase agreements for Commission approval	TBD

*The utility may adjust this date to a day after day 24, as necessary, without Commission approval.

11. Organization of 2014 RPS Procurement Plans and Supplements

For the next RPS procurement cycle, the Commission adopts a slightly different approach than used with the 2006, 2007, 2008, 2009, 2011, 2012 and 2013 Plans.[133] The filing and service of 2014 draft RPS Procurement Plans and draft solicitation protocols by utilities is – consistent with prior years - expected to occur during the first half of 2014. The final schedule will be announced in a

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[133] D.05-07-039 at 29; D.06-05-039 at 58, D.07-02-011 at 61, D.08-02-008, *Opinion Conditionally Accepting Procurement Plans for 2008 RPS Solicitations* (February 2, 2008) at 46; D.09-06-018, *Decision Conditionally Accepting Procurement Plans for 2009 Renewables Portfolio Standard Solicitations and Integrated Resource Plan Supplements* at 70. No solicitations were held in 2011. *See* also, D.11-04-030 and D.12-11-016.

ruling. In the past, this ruling has been issued as an ACR. Today's decision permits the use of either an ACR or an ALJ ruling. This change is discussed in greater detail in section 9, herein. The ruling or ACR will also address the 2014 review of the ESPs' procurement plans.[134] The multi-jurisdictional utility, PacifiCorp, may file Supplements or Integrated Resource Plans consistent with this decision, D.08-05-029, and D.11-04-030.

12. Praxair and Liberty Power Delaware: Requests for Provisional Waiver from Future RPS Compliance Requirements

Today's decision grants, in part, the July 17, 2013 motion by Praxair, entitled *Motion for Provisional Waiver from Future RPS Compliance Requirements.*[135] We also grant a similar request by Liberty Power Delaware.[136] Our decision only addresses the requests of Praxair and Liberty Power Delaware as it applies to the annual procurement plans.

Praxair is a registered ESP that has not served retail electric load since December 10, 2008.[137] Praxair requests a "provisional waiver" from other future RPS planning submissions and progress reports going forward, until such time that it resumes serving direct access customer accounts.[138] The exact reports included in Praxair's request are not specifically identified but appear to include

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

[135] Praxair July 17, 2013 Motion at 3.

[136] Liberty Power Delaware July 11, 2013 RPS Procurement Plan at 3.

[137] Praxair July 17, 2013 Motion at 3.

[138] Praxair July 17, 2013 Motion at 3.

all the annual progress and compliance filings, including the annual RPS Procurement Plan.

Liberty Power Delaware is also a registered ESP and it has never served any retail electric load.[139] It requests a similar "provisional waiver" from all reports, including the RPS Procurement Plan.[140]

Because Praxair and Liberty Power Delaware do not serve any retail customers at this point in time, they are not required to purchase renewable energy under the Commission's RPS Program. Therefore, as long as Praxair or Liberty Power Delaware do not serve retail load and remain registered ESPs, we will not require the filing of an annual procurement plan pursuant to § 399.12(a)(1) for these two entities. We do not address the applicability of any other compliance filing requirements to these two entities. This ruling only applies to Praxair and Liberty Power Delaware, and other ESPs must file a motion to obtain similar relief.

To further reduce administrative burdens, we encourage ESPs to consider seeking permission to withdraw their registration if they have no near-term plans to serve load.

13. Motions for Confidential Treatment

Unless otherwise addressed herein, all motions seeking confidential treatment of information set forth in the 2013 draft RPS Procurement Plans are granted.

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139 Liberty Power Delaware July 11, 2013 RPS Procurement Plan at 1.

140 Liberty Power Delaware July 11, 2013 RPS Procurement Plan at 3.

14. Comments on Proposed Decision

The proposed decision ALJ DeAngelis in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on ____________ and reply comments were filed on _________________.

15. Assignment of Proceeding

Mark J. Ferron is the assigned Commissioner and Regina M. DeAngelis is the assigned ALJ in this proceeding.

Findings of Fact

1. Provided that SDG&E's Commission-approved projects achieve commercial operation, SDG&E will likely have fulfilled its renewables commitment per D.08-12-058 on the Sunrise Powerlink Transmission Project. SDG&E's Commission-approved projects include approximately 3,600 GWh.

2. A value component to reflect existing facilities with expiring contracts exists within the LCBF methodology.

3. PG&E provides for offers for extension so that existing facilities can compete in the RPS solicitations and secure extensions before PG&E fills in its long-term next short.

4. The 2013 draft RPS Procurement Plans filed by SDG&E and PG&E refer to so-called green pricing options which the Commission is evaluating in other proceedings.

5. An integration cost adder must be developed and be based on an assessment of system-wide grid impacts and the costs to customers. This analysis should include ways that renewable procurement can be used to enhance grid reliability.

6. The record of this proceeding is insufficient to assess the risks and benefits to ratepayers and the resource adequacy market on the topic of a seller's offer to include third-party resource adequacy.

7. A completed Phase II transmission study provides more certainty regarding transmission costs and timing and is a reasonable approach to minimize project failure risk.

8. The increased level of competition in the renewables market renders *shortlist exclusivity* unnecessary.

9. A contract term that requires sellers to accept a lower price if deliveries fail to conform to seller's delivery profile (within a designated margin of error) offers utilities a means of managing supply.

10. The value of unlimited buyer curtailment is not known.

11. The more limited changes to curtailment by the buyer, such as proposed by SCE, will not impact project financing.

12. In evaluating preferences, we seek to balance providing the utilities with a reasonable amount of discretion in establishing the parameters of their solicitations with obtaining the most favorable outcomes in the solicitations by not unduly restricting seller participation with otherwise beneficial projects.

13. We envision the RPS Program as a program with broad eligibility.

14. It is unclear that PG&E needs additional procurement under the "adequate" bank proposal due to the absence of analysis.

15. Regarding PG&E's proposed change to its PAV methodology, PG&E did not demonstrate the representative cost to PG&E and its ratepayers by the "contract term length" adjustment.

16. PG&E's proposal to require sellers to bear all integration-related charges attributed to the seller's resource is not supported by the record in this proceeding.

17. Deferring the adoption of a non-zero integration cost adder is reasonable until developed in a public forum.

18. PG&E does not sufficiently justify its proposed project development security of $300/kW for Portfolio Content Category 1 and 2 products.

19. Public disclosure of the PG&E RPS cost quantification information, cited here, will not harm PG&E or its ratepayers.

20. SCE's modification to its LCBF methodology for only the 2013 solicitation to include a congestion cost adder to energy-only projects may appropriately address the risks related to transmission capacity for those projects.

21. No clear benefits exist with SCE's proposal to impose the risks of negative pricing on sellers of energy-only projects.

22. Additional information is needed from PacifiCorp regarding its planned unbundled REC solicitation.

23. The pro forma agreements are negotiable, except for the "standard terms and conditions" and serve as the starting point for negotiating a final agreement between the seller and utility.

24. Praxair and Liberty Power Delaware are ESPs and do not serve any retail load.

Conclusion of Law

1. The Commission is committed to continuing to monitor renewable procurement activities in Imperial Valley but declines the requests for additional oversight mechanisms based on, among other things, the continued robust procurement in the area.

2. With approximately 3,600 GWh under contract, it is reasonable to find that SDG&E will likely have fulfilled the directive in D.08-12-058 regarding renewable contracts facilitated by Sunrise Powerlink Transmission Project.

3. Because a value component to reflect existing facilities with expiring contracts exists within the LCBF, no further value component is needed.

4. Existing contracts have opportunities in the upcoming solicitation as noted by PG&E provision for *offers for extension* so that existing facilities can compete in the RPS solicitations and secure extensions before PG&E fills in its long-term next short.

5. While the 2013 draft RPS Procurement Plans filed by SDG&E and PG&E refer to so-called green pricing options, which the Commission is evaluating in other proceedings, this decision does not find that procurement described in these separate application proceedings is RPS-eligible.

6. Because an RPS integration cost adder should depend on a broader assessment of the electric system's needs, we refrain from adopting an RPS integration cost adder in this decision.

7. PG&E's proposal to require sellers to bear all integration-related charges attributed to the seller's resource is not authorized because it is not support by the record in this proceeding.

8. Because the record of this proceeding is insufficient to assess the risks and benefits to ratepayers and the resource adequacy market on the topic of a seller's offer to include third-party resource adequacy, we do not adopt the proposal today.

9. We accept SCE's and SDG&E's Phase II (or equivalent) study requirement because requiring projects to have at minimum a completed Phase II transmission study provides more certainty regarding transmission costs and

timing and is a reasonable approach to minimize project failure risk. PG&E should also incorporate this requirement into its final 2013 RPS Plan.

10. The contract negotiating arrangement referred to as *shortlist exclusivity* is not permitted based on the increased level of competition in the renewables market.

11. The TOD factors presented in the 2013 RPS Procurement Plans are reasonable although different from those applied in 2012 or previous years.

12. It is reasonable to allow utilities to require a delivery profile from sellers because the information offers increased supply predictability.

13. Consistent with past Commission decisions, utilities are not required to compensate sellers for the loss of production tax credits due to curtailment.

14. It is reasonable for utilities to solicit offers based on the preferences set forth in the 2013 RPS Procurement Plans.

15. Unlimited buyer curtailment is not reasonable due to unknown risks and benefits.

16. The minor revisions to buyer curtailment proposed by SCE are reasonable because the modifications will not impact project financing.

17. Utilities may rely on preferences for project sizes for their solicitations but the RPS Program remains potentially available to all projects with a minimum size of 1.5 MW.

18. In the absence of sufficient analysis, PG&E has not demonstrated its need for additional procurement to establish an "adequate" bank.

19. PG&E's proposed change to its PAV methodology is not accepted because PG&E did not demonstrate the representative cost to PG&E and its ratepayers by the "contract term length" adjustment. In all other respects, the PAV methodology is accepted.

20. The record of this proceeding does not support adoption of a contract provision requiring sellers to bear all integration-related charges attributable to the seller's resource.

21. Without additional evidence, PG&E proposed project development security of $300/kW for Portfolio 1 and 2 products, which is higher than SCE's and SDG&E's, is unreasonable.

22. PG&E's request for confidential treatment of its RPS cost quantification information is denied, in part, because we find that making this aggregated RPS cost data public will not harm PG&E or its ratepayers.

23. SCE's modification to its LCBF methodology for only the 2013 solicitation to include a congestion cost adder to energy-only projects may appropriately address the risks related to transmission capacity for those projects.

24. SCE's proposal to impose the risks of negative pricing on sellers of energy-only projects is not accepted due to the absence of clear benefits.

25. Additional information is needed from PacifiCorp regarding its planned unbundled REC solicitation.

26. The annual solicitation process may be initiated by either an ALJ ruling or a ruling by the Assigned Commission to provide for added flexibility to the process.

27. It is reasonable to not require two ESPs, Praxair and Liberty Power Delaware, to file procurement plans because they do not serve any retail load.

28. In the absence of additional statutory analysis, it is not reasonable to grant Bear Valley Electric Service an exemption from filing annual procurement plans.

29. Unless otherwise addressed herein, all the motions requesting confidential treatment are consistent with Commission decisions and are granted.

O R D E R

IT IS ORDERED that:

1. Pursuant to the authority provided in Pub. Util. Code § 399.13(a)(1), the draft 2013 Renewables Portfolio Standard Procurement Plans, including the related Solicitation Protocols, filed by Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are conditionally accepted, as modified in the Ordering Paragraphs that follow.

2. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall file final Renewables Portfolio Standard (RPS) Procurement Plans with the Commission to initiate the RPS solicitation process within 14 days of the mailing date of this decision pursuant to the RPS solicitation schedule adopted in Ordering Paragraph 7.

3. All future Renewables Portfolio Standard annual procurement plans filed pursuant to Pub. Util. Code § 399.11 *et seq.* must include a separate section addressing safety considerations.

4. The Commission's Energy Division Staff shall continue to monitor development of projects under the Renewables Portfolio Standard (RPS) Program in the Imperial Valley according to the parameters set forth in Appendix A of Decision 09-06-018. In addition, Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company are directed to provide a specific assessment of the offers and contracted projects in the Imperial Valley region in future RPS Procurement Plans filed with the Commission pursuant to Pub. Util. Code § 399.11 *et seq.* until directed otherwise by the Commission.

5. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall provide information on contracts expected to expire through 2023 in all future Renewables Portfolio Standard Procurement Plans until otherwise directed by the Commission.

6. In the final 2013 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall incorporate the Standard Term and Condition 2 (STC 2) adopted by this decision for use in all contracts for RPS procurement signed on or after January 1, 2014. The STC 2 adopted today supersedes the existing STC 2.

7. The following schedule is adopted for the 2013 Renewable Portfolio Standard (RPS) solicitation:

Schedule for 2013 Solicitation

Line No.	Item	No. of Days (cumulative)
1	Mailing of Commission decision conditionally accepting 2012 RPS Procurement Plans	0
2	PG&E, SCE and SDG&E file final 2013 RPS Procurement Plans	14
3	PG&E, SCE, and SDG&E issue RFOs (unless amended Plans are suspended by Energy Division Director by Day 24)*	24
4	PG&E, SCE, and SDG&E submit shortlists to Commission and Procurement Review Group	120
5	PG&E, SCE, and SDG&E file by Tier 2 advice letter (a) Evaluation Criteria and Selection Process Report and (b) Independent Evaluator's Report	150
6	PG&E, SCE and SDG&E 2013 RPS RFO Shortlists Expire	485
7	PG&E, SCE, and SDG&E submit Advice Letters with	TBD

Line No.	Item	No. of Days (cumulative)
	contracts/power purchase agreements for Commission approval	

*The utility may adjust this date to a day after day 24, as necessary, without Commission approval.

8. The Energy Division Director is authorized, after notice to the service list of this proceeding, to change the schedule as appropriate or as necessary for the efficient administration of the 2013 Renewables Portfolio Standard solicitation process.

9. In the final 2013 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company are not authorized to include language regarding the use of non-zero integration cost adders.

10. In the final 2013 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) are authorized to include in their RPS bid solicitation protocols a requirement for a California Independent System Operator Generation Interconnection and Deliverability Procedures (or Generation Interconnection Procedures) Phase II (or equivalent) study to bid into its 2013 RPS solicitation. Pacific Gas and Electric Company (PG&E) shall modify its final 2013 RPS Procurement Plan to include the same requirement. This directive applies to future RPS Procurement Plans filed by PG&E, SCE, and SDG&E.

11. In the final 2013 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific

Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are not authorized to require shortlist exclusivity as part of the contract negotiating process. Shortlist exclusivity is not permitted in future RPS solicitations.

12. In the final 2013 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are authorized to require sellers to deliver generation that meets an expected delivery profile and to pay sellers a lower price (or no price) if sellers are not able to deliver within certain parameters.

13. In the final 2013 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company is not authorized to include a pro forma contract provision that requires buyer to agree to unlimited curtailment. The minor revisions proposed by Southern California Edison Company to the curtailment provisions are accepted. San Diego Gas & Electric Company offered no revisions to curtailment provisions.

14. In the final 2013 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are authorized to include varying preferences.

15. In the final 2013 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company is not authorized to include procurement for Portfolio Content Category 2 and 3 Renewables Portfolio Standard products to build and maintain an "adequate" bank.

16. In the final 2013 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, the use of the Pacific Gas and Electric Company's Portfolio-Adjusted Value methodology, as modified to exclude contract term length adjustment, is accepted for only the 2013 solicitation.

17. In the final 2013 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company is not authorized to include a provision that requires the seller to bear all integration-related charges that are attributable to the seller's resource.

18. In the final 2013 Renewables Portfolio Standard (RPS) Procurement Plan to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company (PG&E) shall modify its 2013 RPS Solicitation Protocol and other parts of its 2013 draft RPS Procurement Plan, as necessary, to include a project development security equivalent of Southern California Edison Company's $90/kilowatt (kW) for baseload resources and $60/kW for intermittent resources for Portfolio Content Category 1 and 2 products.

19. In the final Renewables Portfolio Standard (RPS) Procurement Plan to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company (PG&E) shall make public specific information redacted in its draft 2013 RPS Procurement Plan, unless doing so would reveal a single RPS contract price that would otherwise be covered by Decisions 06-06-066 and 08-04-023. Specifically, the information to be made public is cited as follows:

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Page 109, Table 12-1, rows 1, 2, 5 and row 8 for 2017 and beyond

Page 110, Table 12-1, rows 1, 2, 5 and 8

Appendix 2, Table 1, rows 11, 12 and 14

Appendix 2, Table 2, rows 2, 3, 6, 11, 12, 14 (for 2017 and beyond), 16-26, 28-29 (for 2017 and beyond)

20. In the final 2013 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Southern California Edison Company is permitted, for only the 2013 solicitation, to incorporate a congestion cost adder into its least cost, best fit methodology for energy-only projects.

21. In the final 2013 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Southern California Edison Company is not authorized to include changes to its proposed 2013 RPS pro forma contract related to seller's bearing the risks of negative pricing for energy-only projects.

22. The 2013 Renewables Portfolio Standard (RPS) Procurement Plans filed by the smaller utilities, Bear Valley Electric Service and Liberty Utilities (CalPeco Electric) LLC are accepted and deemed final.

23. Pursuant to Pub. Util. Code § 365.1(c)(1) and Decision 11-01-026, the 2013 Renewables Portfolio Standard (RPS) Procurement Plans filed by electric service providers (ESPs) are accepted and deemed final, including, 3 Phases Renewables, Calpine PowerAmerica-CA, LLC, Commercial Energy of California, Consolidated Edison Solutions, Inc., Constellation NewEnergy, Inc., Direct Energy Business, LLC, Direct Energy Service, LLC, EDF Industrial Power Services (CA), LLC, EnerCal USA, LLC, Gexa Energy California, LLC, Liberty Power Delaware, LLC, Liberty Power Holdings, LLC, Noble Americas Energy Solutions LLC, Pilot Power Group, Inc., Praxair Plainfield, Inc., Shell Energy

North America (US), L.P., Southern California Telephone & Energy, Tiger Natural Gas, Inc.

24. Praxair Plainfield, Inc. and Liberty Power Delaware, LLC are not required to file an annual procurement plan pursuant to § 399.12(a)(1) until retail load is served.

25. Bear Valley Electric Service's request for exemption from annual Renewables Portfolio Standard Procurement Plans is denied.

26. Unless otherwise addressed herein, all motions filed seeking confidential treatment of information set forth in the 2013 draft RPS Procurement Plans and final plans are granted.

27. On or before 14 days of the mailing date of this decision pursuant to the Renewables Portfolio Standard solicitation schedule adopted herein, PacifiCorp shall file an amended On-Year Supplement that includes information regarding its planned unbundled Renewable Energy Credit solicitation, including a pro forma contract.

28. Rulemaking 11-05-005 remains open.

This order is effective today.

Dated ________________________________, at San Francisco, California.