STATE OF CALIFORNIA EDMUND G. BROWN JR.

PUBLIC UTILITIES COMMISSION
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SAN FRANCISCO, CA 94102-3298

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TO PARTIES OF RECORD IN RULEMAKING 15-02-020

This is the proposed decision of Administrative Law Judges Robert M. Mason III, Anne E. Simon and Nilgun Atamturk. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's December 14, 2017 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Upon the request of any Commissioner, a Ratesetting Deliberative Meeting (RDM) may be held. If that occurs, the Commission will prepare and publish an agenda for the RDM 10 days beforehand. When the RDM is held, there is a related ex parte communications prohibition period. (See Rule 8.3(c)(4).)

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

<u>/s/ ANNE E. SIMON</u>
Anne E. Simon
Acting Chief Administrative Law Judge

AES:ek4
Attachment

Decision **PROPOSED DECISION OF ADMINISTRATIVE LAW JUDGES MASON, SIMON AND ATAMTURK (MAILED 11/14/2017)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	Rulemaking 15-02-020

DECISION ACCEPTING DRAFT 2017 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS

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DECISION ACCEPTING DRAFT 2017 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS

Summary

Pursuant to the authority provided in Pub. Util. Code § 399.13(a)(1),[1] today's decision accepts the draft 2017 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).

The request of PG&E, SCE, and SDG&E to forgo holding a 2017 RPS solicitation is approved. We direct PG&E, SCE, and SDG&E to file final 2017 RPS Procurement Plans pursuant to the schedule adopted herein. No incremental procurement beyond existing RPS mandates is ordered in this decision.

This decision authorizes PG&E, SCE, and SDG&E to conduct solicitations for the short-term, meaning 5 years or less, sales of RPS volumes during the timeframe covered by the 2017 RPS Procurement Plans, or prior to the Commission issuing a decision on the 2018 RPS Procurement Plans. PG&E, SCE, and SDG&E must submit a Tier 1 Advice Letter for Commission approval of short-term sales resulting from a solicitation. This decision also approves the request of PG&E, SCE, and SDG&E to engage in bilateral transactions to sell RPS volumes, subject to the Commission's review and approval of completed transactions through a Tier 3 Advice Letter process that was established in Decision (D.) 09-06-050.

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[1] Pub. Util. Code § 399.13(a)(1) orders the Commission to "direct each electric corporation to annually prepare a renewable energy procurement plan…to satisfy its obligations under the renewables portfolio standard." As well as "require other retail sellers to prepare and submit renewable energy procurement plans…" All subsequent code section references are to the Public Utilities Code unless otherwise indicated.

This decision also accepts the draft 2017 RPS Procurement Plans filed by the following 31 retail sellers of electricity that are subject to California's RPS program:

Small and Multi-jurisdictional Utilities: Bear Valley, Liberty Utilities (CalPeco Electric), and PacifiCorp.

Community Choice Aggregators (CCAs): Redwood Coast Energy Authority, Apple Valley Choice Energy, Marin Clean Energy, Pico Rivera Innovative Municipal Energy, Silicon Valley Clean Energy, Sonoma Clean Power Authority, Peninsula Clean Energy, CleanPowerSF, and Lancaster Choice Energy.

Electric Service Providers (ESPs): 3 Phases Renewables, Agera Energy, LLC, American PowerNet Management, LP, Calpine PowerAmerica-CA, LLC, CalPine Energy Solutions, LLC, Commerce Energy of Montana, Inc. (dba Commercial Energy of California), Constellation NewEnergy, Inc., Direct Energy Business LLC, Direct Energy Services, LLC, EDF Industrial Power Services (CA), LLC, EnerCal USA, LLC (dba Yep Energy, Y.E.P.), Gexa Energy California, LLC, Just Energy Solutions, Inc., Liberty Power Holdings, LLC, Palmco Power CA, Pilot Power Group, Inc., Shell Energy North America (US), L.P., The Regents of the University of California, and Tiger Natural Gas, Inc.

This proceeding remains open.

1. Background

The Commission has adopted a framework for consideration of Renewables Portfolio Standard (RPS) Procurement Plans for electric corporations and other RPS obligated retail sellers in prior decisions. The definition of "retail seller" in Public (Pub.) Utilities (Util.) Code § 399.12(j) includes the electrical corporations, as defined in Pub. Util. Code § 218, community choice aggregators

(CCAs) and electric service providers (ESPs). The most recent decision is Decision (D.) 16-12-044.[2] Consistent with the general process referred to in D.16-12-044, other prior Commission decisions, and the requirements in Senate Bill (SB) 350,[3] the parties were required to file their proposed RPS Procurement Plans for 2017 and to set forth the information required therein.

On May 26, 2017, the assigned Commissioner and assigned Administrative Law Judge issued a ruling *Identifying Issues and Schedule of Review for 2017 Renewables Portfolio Standard Procurement Plans and Inviting Comments on Renewable Auction Mechanism Proposal* (*2017 ACR*). The following retail sellers submitted draft 2017 RPS Procurement Plans on or before July 21, 2017, after an extension of time requested by Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), and Pacific Gas and Electric Company (PG&E) was granted by the Administrative Law Judge:

Investor-Owned Utilities (IOUs): SCE, SDG&E, and PG&E.

Small and Multi-Jurisdictional Utilities: Bear Valley, Liberty Utilities (CalPeco Electric), and PacifiCorp.

Community Choice Aggregators (CCA): Redwood Coast Energy Authority, Apple Valley Choice Energy, Marin Clean Energy, Pico Rivera Innovative Municipal Energy, Silicon Valley Clean Energy, Sonoma Clean Power Authority, Peninsula Clean Energy, CleanPowerSF, and Lancaster Choice Energy.

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[2] *Decision Accepting Draft 2016 Renewables Portfolio Standard Procurement Plans* (December 15, 2016). In D.16-12-044, the Commission adopted RPS Procurement Plans for the year 2016.

[3] SB 350 (De Leon, Stats. 2015, ch.547).

Electric Service Providers (ESPs): 3 Phases Renewables, Agera Energy, LLC,[4] American PowerNet Management, LP, Calpine PowerAmerica-CA, LLC, CalPine Energy Solutions, LLC, Commerce Energy of Montana, Inc. (dba Commercial Energy of California), Constellation NewEnergy, Inc., Direct Energy Business LLC, Direct Energy Services, LLC, EDF Industrial Power Services (CA), LLC, EnerCal USA, LLC (dba Yep Energy, Y.E.P.), Gexa Energy California, LLC, Just Energy Solutions, Inc., Liberty Power Holdings, LLC, Palmco Power CA,[5] Pilot Power Group, Inc., Shell Energy North America (US), L.P., The Regents of the University of California, and Tiger Natural Gas, Inc.

The following CCAs filed implementation plans but have not yet filed RPS plans: City of San Jacinto CCA, Monterey Bay Community Power, and Valley Clean Energy. Per the comments filed in this proceeding, CCAs must file their RPS plans upon registering with the Commission or 90 days prior to serving load, whichever event occurs first.

The following parties did not file RPS plans but have been granted the relief requested in their *Motions for Provisional Waiver from Future RPS Compliance Reports* in D.13-11-024: Liberty Power Delaware LLC and Praxair Plainfield, Inc.

The following parties filed *Motions for Provisional Waiver from Future RPS Compliance Reports*: Mansfield Power and Gas, LLC (filed August 4, 2017); Tenaska California Energy Marketing, LLC (filed July 13, 2017); and Tenaska Power Services Co. (filed July 13, 2017).[6]

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[4] Agera Energy, LLC late filed its RPS Plan on July 31, 2017.

[5] Palmco Power CA late filed its RPS Plan on July 31, 2017.

[6] This waiver only applies to the RPS Procurement Plans filing requirement. All retail sellers must continue to file annual RPS compliance reports.

Assigned Commissioner Ruling

As mentioned above, on May 26, 2017, the Assigned Commissioner and Assigned Administrative Law Judge's issued a ruling setting the reporting requirements and schedule for the 2017 RPS procurement planning process. The *2017 ACR* also included a proposal for additional RPS procurement using the Renewable Auction Mechanism (RAM). The following parties filed comments on the RPS Plans on August 18, 2017: American Wind Energy Association California Caucus (ACC), Independent Energy Producers Association (IEPA), Large-Scale Solar Association (LSA), Office of Ratepayer Advocates (ORA), and Shell Energy North America (Shell).

The following parties filed reply comments on September 1, 2017: PG&E, SDG&E, SCE, ORA, Shell, IEPA, Clean Coalition, and Lancaster Choice Energy, Marin Clean Energy, Redwood Coast Authority, Silicon Valley Clean Energy Authority and Sonoma Clean Power Authority (CCA Parties).

RPS Program Status

The three large IOUs report RPS progress in excess of program procurement requirements, which mandate a 25% RPS by 2017. For 2016, the IOUs delivered the following percentages of energy from RPS-eligible resources: PG&E 32.9%; SCE 28.2%; and SDG&E 43%.

None of the three large IOUs (PG&E, SCE, and SDG&E) conducted a 2016 annual RPS solicitation. All three large IOUs continued to procure through their feed-in tariff (renewable market adjusting tariff (ReMAT)) and renewable auction mechanism (RAM) programs. A total of 1,405 Megawatts (MW) was authorized for procurement through six RAM auctions, which resulted in a total of 1,532 MW of approved contracts.[7]

Because of the level of RPS procurement achieved over the previous years, some of the IOUs sought permission to terminate their RAM procurement requirements. Both PG&E and SDG&E claimed in their respective filings that their current resources and load forecasts demonstrate that they are positioned to meet their respective near-term RPS requirements without the necessity of additional RAM solicitations,[8] the Commission denied both of these requests to rescind prior Commission order, given the ongoing need to decarbonize California's electricity supply while maximizing the value of California's existing and potential renewable resources. The Commission found that the continuation of RAM played a vital role in achieving California's long-term greenhouse gas reduction goals.[9]

2. Plan of this Decision

The RPS statute requires that retail sellers prepare an annual RPS procurement plan for Commission review (Pub. Util. Code § 399.13(a)). The Commission has reviewed and approved or accepted annual RPS procurement plans for over 10 years. As the RPS program has matured, parties' review of the

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[7] The differential in authorized versus the amount procured was due to SDG&E procuring approximately 40 percent of its target. Decision (D.) 10-12-048 at 31 and Ordering Paragraph 1 requires that any contracted capacity that is not successfully developed must be added back to that IOU's procurement obligation to be sourced at subsequent auctions. As a result, the amount approved by the Commission (1,532 MW) is higher than what is ultimately authorized (1,405 MW).

[8] On October 27, 2016, SDG&E filed a Petition to Modify Decision 10-12-048, Decision 12-02-002, and Decision 14-11-042, as well as an Application for Modification of Resolution E-4783 to Terminate its Renewable Auction Mechanism Procurement Requirement. On January 22, 2016, PG&E filed a Petition to Modify Decision 14-11-042.

[9] D.17-09-020; D.17-08-025.

three large IOUs' procurement plans has become more routine. This year, 2017, marks the third year in a row that PG&E and SDG&E will forgo an annual RPS solicitation; it is the second year in a row for SCE.

In light of all the above, for ease of review, this year's decision accepting the RPS procurement plans is shorter than past years. It describes only the sections of the IOUs' procurement plans that are at issue, and those responses to the *2017 ACR* that are relevant to our decision to grant the IOUs' request to forego an RPS solicitation. This decision accepts the plans in their entirety, as modified herein, subject to approval of the required compliance filings.

3. General Requirements for 2017 RPS Procurement Plans

The RPS procurement process continues to evolve since the beginning of the RPS program. The procurement plans include long-standing elements, such as standard terms and conditions that must be included in each RPS pro forma contract. Legislative changes to the RPS statute impact retail sellers' RPS procurement plans. This was the case with SB 2 (1X) (Simitian, Stats. 2011, ch.1), which increased and extended the RPS requirement from 20% by 2010 to 33% by 2020. The Commission has implemented SB 2 (1X) in several Commission decisions, including D.11-12-020,[10] D.11-12-052,[11] D.12-06-038[12]. These Commission decisions contain directives that required modifications to the RPS procurement process, the details of these decisions are not repeated here.

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[10] *Decision Setting Procurement Quantity Requirements for Retail Sellers for the Renewables Portfolio Standard Program*, December 1, 2011.

[11] *Decision Implementing Portfolio Content Categories for the Renewables Portfolio Standard Program*, December 15, 2011.

[12] *Decision Setting Compliance Rules for the Renewable Portfolio Standard Program*, June 21, 2012.

More recently, SB 350 (De León, 2015) further extended the RPS program targets, including changes to RPS procurement rules. SB 350 also clarified and expanded the RPS procurement plan reporting requirements for CCAs and ESPs. On June 29, 2017, the Commission issued D.17-06-026 (*Decision Revising Compliance Requirements for the California Renewables Portfolio Standard in Accordance with Senate Bill 350*). Set to go into effect beginning with the compliance period that runs from January 1, 2021 to December 31, 2024, the changes affect the role of long-term contracts in RPS procurement requirements and the methodology for determining how excess procurement in one compliance period may be applied to later compliance periods.

The *2017 ACR* instructed that the proposed 2017 RPS Procurement Plans should reflect recent statutory changes. For example, if the retail seller intends to procure more short-term contracts and comply with Pub. Util. Code § 399.13(b) beginning January 1, 2018, then its 2017 RPS Procurement Plan should clearly reflect that intended procurement and intended compliance. In order to align their procurement planning with the changes made by SB 350, any retail sellers whose draft procurement plans do not include an assumption that the procurement quantity requirement will be at least 50% of retail sales beginning in 2031 should revise their plans to include that assumption.

Consistent with the Commission's decisions and applicable statutory changes, compliance with all of the requirements set forth in the *2017 ACR* is required by the three large IOUs. The *2017 ACR* also stated that small and multi-jurisdictional utilities are subject to a subset of the requirements the ACR identified. ESPs and CCAs are also subject to a subset of these requirements.

As indicated in the *2017 ACR*, the 2017 Procurement Plans must include all information required by statute, as well as quantitative analysis supporting the retail seller's assessment of its RPS portfolio and future procurement decisions.

The *2017 ACR* identified the following information for inclusion in the 2017 Procurements Plans:

- Assessment of RPS Portfolio Supplies and Demand (Section 6.1);
- Project Development Status Update (Section 6.2);
- Potential Compliance Delays (Section 6.3);
- Risk Assessment (Section 6.4);
- Quantification Information (Section 6.5);
- "Minimum Margin" of Procurement (6.6);
- Bid Solicitation Proposal, Including Least-Cost Best-Fit Methodologies (6.7);
- Consideration of Price Adjustment Mechanisms (6.8);
- Curtailment Frequency, Costs, and Forecasting (6.9);
- Expiring Contracts (6.10);
- Cost Quantification (6.11);
- Important Changes to Plans Noted (6.12);
- Redlined Copy of Plans Required (6.13); and
- Safety Considerations (6.14).

The *2017 ACR* instructed the parties that all of the proposed 2017 RPS Procurement Plans must achieve the following:

1. Describe the overall plan for procuring RPS resources for the purposes of satisfying the RPS program requirements while minimizing cost and maximizing value to ratepayers. This includes, but is not limited to, any plans for building utility-owned resources, investing in renewable resources, and engaging in the sales of RPS eligible resources.
2. The various aspects of the plans themselves must be consistent. For instance, the bid solicitation protocol

should be consistent with any statements and calculations regarding a utility's renewable net short position.[13]

3. The plans should be complete in describing and addressing procurement (and sales) of RPS eligible resources such that the Commission may accept or reject proposed contracts based on consistency with the approved plan, including any calculation of RPS procurement net short position.[14]
4. IOUs should work collaboratively to make the format of the plans as uniform as possible to enable parties, bidders, and the Commission to easily access, review and compare the plans.

The *2017 ACR* also sought comments on a proposal that would direct procurement for incremental renewable resources at geographic locations identified by an IOU that provide the most value to the utility based on existing or future expected conditions on the electric grid. The proposal was put forward notwithstanding an IOU possessing sufficient RPS resources under contract to meet immediate RPS requirements. The main concepts of the RAM proposal are as follows:

- Each IOU will identify at least two (in total) specific locations or geographic boundaries where renewable resources, with or without energy storage, can be interconnected to ameliorate a sub-optimal grid condition, such as underutilization of RPS-eligible generation, prevent renewable curtailment, or provide frequency regulation;
- Each IOU will solicit at least 20 MW of one or more resource types; and

[13] The methodology can be found at the May 21, 2014 ruling, *Administrative Law Judge's Ruling on Renewable Net Short*. (R.11-05-005).

[14] Pub. Util. Code § 399.13(d).

- Each IOU will use a RAM process, with solicitation protocols and contract terms and conditions necessary to support the objectives herein.

The following parties filed comments on the proposal:[15] PG&E, SCE, SDG&E, the CCAs, ORA, Clean Coalition, and LSA. PG&E, SCE, SDG&E, and ORA filed reply comments. CalWEA did not comment directly on the proposal and instead offered their proposal for a Small Wind RAM Program.

4. Utilities Subject to Pub. Util. Code § 399.17

RPS procurement requirements for multi-jurisdictional utilities and their successors[16] allow these utilities to meet their RPS procurement obligations without regard to the portfolio content category limitations in Pub. Util. Code § 399.16.[17] Multi-jurisdictional utilities, *i.e.*, PacifiCorp, also have the ability to use an Integrated Resource Plan (IRP) prepared for regulatory agencies in other states to satisfy the annual RPS Procurement Plan requirement so long as the IRP complies with the requirements specified in Pub. Util. Code § 399.17(d). PacifiCorp prepares its IRP on a biennial schedule, filing its plan in odd numbered years. It files a supplement to this plan in even numbered years.

As required by D.08-05-029, PacifiCorp must file and serve its IRP in Rulemaking (R.) 06-05-027 or its successor proceeding at the same time it files with the jurisdictions requiring the IRP, and an IRP Supplement within 30 days of filing its IRP. PacifiCorp filed its 2017 IRP on April 4, 2017, an Amendment to its 2017 IRP on April 11, 2017, and its "on year" supplement to its 2017 IRP on May 4, 2017.

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[15] Parties filed opening comments on June 19, 2017, and reply comments on June 30, 2017.

Liberty Utilities (Liberty), on the other hand, is not a multi-state utility and does not prepare an IRP. Therefore, we required that Liberty prepare an RPS Procurement Plan subject to the same requirements as a small utility under Pub. Util. Code § 399.18.

5. Utilities Subject to § 399.18

Pub. Util. Code § 399.18(b)[18] allows a small utility to meet the RPS procurement obligations without regard to the portfolio content category limitations in Pub. Util. Code § 399.16.

A small utility must file a procurement plan pursuant to Pub. Util. Code § 399.13(a)(5), but it should be tailored to the limited customer base and the limited resources of a small utility.

Accordingly, we required Bear Valley Electric Service (BVES), as well as Liberty to prepare an RPS Procurement Plan providing the information required in Sections 6.1-6.8 and 6.12-6.14 of the *2017 ACR*.

6. Electric Service Providers and Community Choice Aggregators

SB 350 revised the Commission's requirements regarding what entities it shall direct to file RPS Procurement Plans. ESPs and CCAs must now file RPS Procurement Plans consistent with the requirements of Pub. Util. Code § 399.13(a)(5). Therefore, we required each ESP and CCA to file a proposed RPS Procurement Plan that complies with the requirements of sections 6.1-6.5, 6.7, 6.8, and 6.12-6.14 of the *2017 ACR*.

7. PG&E's RPS Procurement Plan

7.1. Summary[19]

Given its current RPS compliance position, PG&E has proposed in its 2017 RPS Plan not to hold an RPS procurement solicitation for the 2017 solicitation cycle. PG&E believes it does not have an incremental need for RPS resources until after 2030. PG&E forecasts that it will meet its RPS compliance requirements through the fifth compliance period (2025-2027) and may apply its excess procurement (Bank) for any incremental RPS procurement need.

Before addressing the specific issues identified in the *2017 ACR*, PG&E makes some preliminary comments regarding its participation in the RPS program and the impact of recent legislative changes. PG&E states that it plans to sell excess RPS volumes in 2018 in accordance with a framework it developed in 2016 that it believes rebalances its RPS portfolio and aligns its RPS position with its RPS needs. PG&E issued a solicitation in 2017 for the short-term sale of bundled RPS products.[20]

PG&E also seeks to suspend or change existing statutory or Commission mandates in order to avoid what it deems unnecessary consumer costs. PG&E believes it should not have to continue procurement under the ReMAT program given the absence of the need for additional RPS volumes.[21] It reasons that it

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[19] PG&E's 2017 RPS Plan at 1-6 (July 21, 2017).

[20] Advice Letter 5095-E, which sought approval of the resulting sales transactions for approximately 2,000 GWh of energy and RECs, became effective on June 16, 2017.

[21] The ReMAT program provides market-adjusting prices for small RPS-eligible generators (i.e., fewer than 3 MW) to sell renewable electricity to utilities under standard terms and conditions. The ReMAT Program replaced the AB 1969 Feed-in Tariff Program in 2013. ReMAT was created through SB 32 and SB 2 (1x), and the Commission implemented the program through D.12-05-035 and D.13-05-034, as modified by AB 1979 and D.17-08-021.

does not support mandated programs that do not optimize costs for customers but, instead, supports a technology-neutral procurement process in which all RPS-eligible technologies can compete to demonstrate which projects provide the best value to customers. PG&E also questions the need to continue procurement under BioMAT, PV RAM, and BioRAM when it does not need to procure additional RPS volumes.[22]

7.2. Assessment of RPS Portfolio Supplies and Demand[23]

7.2.1. Supply

PG&E claims it delivered 32.9% of its electricity from RPS-eligible renewable sources in 2016. PG&E projects that it is positioned to meet its RPS compliance requirements through compliance period (CP 5) (2025-2027).

PG&E's RPS portfolio is comprised of a variety of technologies, project sizes, and contract types. The portfolio includes approximately 8,000 megawatts (MWs) of active projects, ranging from utility-owned solar and small

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[22] The RAM program is a streamlined competitive procurement process for RPS-eligible generation that allows bidders to set their own price, provides a standard contract for each utility, and allows all projects to be submitted to the CPUC through an expedited regulatory review process. The Commission created and implemented RAM through D.10-12-048, as modified and expanded through Commission Resolutions and D.14-11-042.

The BioMAT program required 250 MW of RPS-eligible procurement from small-scale bioenergy projects, allocating procurement to three bioenergy areas: Biogas, Agriculture, and Forest. BioMAT was created by SB 1122, implemented through D.14-12-081 and D.15-09-004, and later modified by the Governor's Emergency Proclamation on Tree Mortality, SB 840, AB 1923, D.16-10-025, and D.17-08-021.

The Commission implemented the BioRAM program through Resolution E-4770 in response to the Governor's October 2015 Emergency Order on Tree Mortality. The program also addresses emergency directives contained in SB 859, which were implemented through Resolution E-4805. Under the program, the IOUs must procure a total of 146 MWs of bioenergy that utilizes High Hazard Zone forest fuel, in order to aid in mitigating the threat of wildfires.

[23] *Id.*, at 12.

hydro generation to long-term RPS contracts for large wind, geothermal, solar, and biomass to small FIT contracts for solar PV, biogas, and biomass generation. Additionally, PG&E reports RECs of sufficient quantities in its excess procurement bank that may be used to satisfy the 50% in 2030 requirement.

PG&E believes that the Green Tariff Shared Renewables Program (GTSR), enacted by SB 43, also has an impact on its supply analysis. In PG&E's estimation, the GTSR Program will impact its RPS position in two ways: RPS supply may be increased, and retail sales will be reduced corresponding to the level of program participation. D.15-01-051 permits the IOUs to supply Green Tariff customers from an interim pool of existing RPS resources until new dedicated Green Tariff projects come online. Generation from these interim facilities would no longer be counted toward PG&E's RPS targets, which will result in PG&E's RPS supply decreasing. However, there is also a possibility that RPS supply might increase in the future if generation from Green Tariff dedicated projects exceeds the demand of Green Tariff customers.

On July 7, 2015, PG&E launched its RAM 6 solicitation seeking 50 MW for the GTSR Program. In December and January 2016, PG&E executed eight GTSR Program PPAs for a total of 52.75 MW, which were filed for approval as part of Advice Letter 4780-E on January 22, 2016. The facilities pursuant to these PPAs are currently under development and their status is included in the Project Development Status Update section below.

7.2.2. Demand

Because PG&E claims it has no immediate incremental procurement need under a 50% RPS requirement, it is proposing not to hold an RPS solicitation for the 2017 solicitation cycle. PG&E expects to continue procurement of additional volumes of incremental RPS-eligible contracts in 2017 through mandated procurement programs, such as the ReMAT and BioMAT Programs.

Also, due to claimed increasing and combined impacts of energy efficiency, Direct Access (DA), customer-sited generation, and CCA participation levels, PG&E is currently projecting a decrease in retail sales in 2017 and a continued retail sales decrease through 2026, followed by modest growth thereafter.

7.2.3. Lessons Learned

As for lessons learned and market trends, PG&E notes that the renewable energy market has developed and now offers a variety of technologies at lower prices than seen in earlier RPS Program years. PG&E has also observed the growth of renewable resources in the California Independent System Operator (CAISO) system has resulted in the downward movement of mid-day market prices. PG&E has also observed that the growth of renewable resources has produced operational challenges such as over generation situations and negative market prices. PG&E asks for contract provisions that will provide it with greater flexibility to bid RPS-eligible resources into the CAISO market or exercise curtailment rights based on CAISO market prices.

7.3. Project Development Status Update[24]

PG&E provides an update on the development of RPS-eligible resources currently under contract but not yet delivering energy in Appendix B to its Plan.

There are 116 RPS-eligible projects that were executed after 2002. Of these contracts, 91 of these projects have achieved full commercial operation and started the delivery term under their PPAs, and 25 projects have not started the delivery term under their PPAs. Of the 25 projects that have not started the delivery term under their PPAs with PG&E: 14 have not yet started construction,

[24] PG&E's 2017 RPS Plan at 25.

and 11 have started construction but are not yet online. Of the 11 projects not yet online, 4 are delivering energy but have not yet met the conditions precedent to start their delivery term.

In addition, 8 of the 116 total RPS-eligible projects are designated for the GTSR Program. Of the eight projects, two have started construction and the remaining six have not started construction. All eight projects are expected to come online by April 2018.

7.4. Potential Compliance Delays[25]

PG&E addressed the risk of potential compliance delays in two categories that identify: (1) obstacles for renewable project developers; and (2) how PG&E mitigates these risks of compliance delay in its modeling and planning. As for the obstacles, PG&E identifies the following: securing project financing, siting and permitting projects, expanding transmission capacity, and interconnecting projects to the grid. As a result, PG&E states that its RPS need calculation incorporates a minimum margin of procurement to account for some anticipated project failure and delays in PG&E's existing portfolio, which are captured in PG&E's deterministic model.

7.5. Risk Assessment[26]

As with prior years' RPS procurement plans, PG&E states that it models the demand-side risk of retail sales uncertainty and the supply-side risks of generation variability, project failure, curtailment, and project delays in quantitative analyses. Specifically, PG&E uses two approaches to modeling risk: (1) a deterministic model which models three risks (standard generation

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[25] *Id*. at 26.

[26] *Id*., at 35.

variability, project failure, and project delay); and (2) a stochastic model which accounts for additional and uncertain variables (retail sales uncertainty, project failure variability, curtailment, and RPS generation variability). The deterministic model tracks the expected values of PG&E's RPS target and deliveries to calculate a "physical net short," which represents a point-estimate forecast of PG&E's RPS position and constitutes a minimum margin of procurement, as required by the RPS statute. These deterministic results serve as the primary inputs into the stochastic model. The stochastic model accounts for additional compounded and interactive effects of various uncertain variables on PG&E's portfolio to suggest a procurement strategy at least cost within a designated level of non-compliance risk. The stochastic model provides target procurement volumes for each compliance period, which result in a designated Bank *(i.e.* the banked volumes of excess procurement) size for each compliance period. The Bank is then primarily utilized as Voluntary Margin of Over-procurement (VMOP) to mitigate dynamic risks and uncertainties and ensure compliance with the RPS.

7.6. Quantitative Information[27]

7.6.1. Deterministic Model Results

PG&E has provided the results from the deterministic model under a 50% RPS target in Row Ga of Appendices C.1 and C.2. Appendix C.1 provides a physical net short calculation using PG&E's March 2017 Bundled Retail Sales Forecast for years 2017-2021 and the LTPP sales forecast for 2022-2037.[28] Appendix C.2 relies on PG&E's internal Bundled Retail Sales Forecast. PG&E

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[27] *Id.*, at 48.

[28] *Id.*, at appx. C.1, C.2.

currently estimates a long-term volumetric success rate of 100% for its portfolio of executed-but-not-operational projects. The annual forecast project failure rate used to determine the long-term volumetric success rate is shown in Row Fbb of Appendix C.2. In addition to the current long-term volumetric success rate, Rows Ga and Gb of Appendix C.2 depict PG&E's expected compliance position using the current expected need scenario before application of the Bank.

As noted above, PG&E believes it is positioned to meet its compliance period requirements through the fifth compliance period (2025-2027).

7.6.2. Stochastic Model Results

Because PG&E uses its stochastic model to inform its RPS procurement, PG&E states it has created an Alternate RNS in Appendix C.2 for the 50% RPS target. Yet, PG&E claims that Appendix C.1 provides an incomplete representation of PG&E's optimized net short, as the formulas embedded in the RNS form required by the ALJ RNS Ruling do not enable PG&E to capture its stochastic modeling inputs and outputs. Rows Gd and Ge show the stochastically-adjusted net short, which incorporates the risks and uncertainties addressed in the stochastic model.

7.7. Margin of Procurement[29]

PG&E claims to consider two components when analyzing its margin of procurement: (1) a statutory minimum margin of procurement to address some anticipated project failure or delay, for both existing projects and projects under contract but not yet online, that is accounted for in PG&E's deterministic model; and (2) a VMOP, which aims to mitigate the additional risks and uncertainties

[29] *Id.*, at 54.

that are accounted for in PG&E's stochastic model. PG&E incorporates both of these components into its quantitative analysis of its RPS need.

7.8. Bid Selection Protocol[30]

Because it believes it is positioned to meet its RPS targets under a 50% target, PG&E proposes not to hold a 2017 procurement solicitation. PG&E will continue to procure RPS-eligible resources in 2017 through other Commission-mandated programs, such as the ReMAT Program. Accordingly, PG&E has not included in the 2017 RPS Plan a solicitation protocol for procuring additional RPS resources, nor is it including an evaluation methodology for such purchases.

7.8.1. Proposed Time of Delivery Factors

PG&E sets its Time of Delivery (TOD) factors based on expected hourly prices. Given the penetration of solar generation expected through 2020 and beyond, PG&E forecasts that there will be periods of time during the mid-day when net loads are low, resulting in prices that will be low or negative, especially in the spring when there is more significant production from hydroelectric resources.[31] In addition, given the low mid-day loads, PG&E sees its peak demand (and resulting higher market prices) moving to later in the day. Capacity value has also become significantly less important in the selection process because: (1) market prices for generic capacity are low; and (2) net qualifying capacity using effective load carrying capability is also low. As a result, PG&E updated its TOD factors as follows:

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[30] *Id.*, at 55.

[31] Net load is the difference between forecasted load and expected generation from variable generation resources, like wind and solar.

TABLE A
PG&E'S PROPOSED TOD FACTORS[32]

	Peak	Mid-Day	Night
Summer	1.546	0.654	1.222
Winter	1.505	0.753	1.229
Spring	1.315	0.200	1.016

- Peak: hour ending (HE) 18 – HE 22
- Mid-day: HE 09 – HE 17
- Night: HE 23 – HE 08
- Summer: Jul. – Sept.
- Winter: Oct. – Feb.
- Spring: Mar. – Jun.

7.9. Economic Curtailment[33]

According to PG&E, the frequency of negative price periods in the first half of 2017 has increased in the Real-Time Markets (RTM) for the PG&E Default Load Aggregation Point (DLAP) and for the North of Path 15 Hub (NP15 Hub). During January through April 2017, negative price intervals in the CAISO

32 PG&E's previously approved TOD factors were the following:

	Peak	Mid-Day	Night
Summer	1.515	0.713	1.003
Winter	1.484	0.674	1.155
Spring	1.109	0.491	1.926

PG&E's RPS Plan at appx. A, at 70.

33 *Id.*, at 65.

Five Minute Market for the PG&E DLAP occurred in approximately 13.5% of the five-minute intervals, compared to approximately 7.6% during the same period in 2016. Trends are similar for NP15 and ZP26.

With regard to longer-term RPS planning and compliance, in order to ensure that RPS procurement need forecasts account for curtailment, PG&E adds curtailment as a risk adjustment within the stochastic model. These modeling assumptions will not necessarily align with the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. PG&E will continue to observe curtailment events and update its curtailment assumptions as needed.

7.10. Expiring Contracts[34]

Appendix E to PG&E's 2017 RPS Plan lists the projects under contract that are expected to expire in the next 10 years. As PG&E notes in Appendix G, its RNS calculations assume no re-contracting.

7.11. Cost Quantification[35]

Appendix D (Tables 1 through 4) to PGE's 2017 RPS Plan provides an annual summary of PG&E's actual and forecasted RPS costs, and quantifies the cost of RPS-eligible procurement—both historical (2003-2016) and forecasted (2017-2030). From 2003 to 2015, PG&E reports its annual RPS-eligible procurement and generation costs increased as renewable energy grows to be the dominant resource for meeting PG&E's electricity supply needs.

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[34] *Id.*, at 68.

[35] *Id.*, at 68.

7.12. Important Changes to Plans Noted[36]

Appendix A to PG&E's 2017 RPS Plan contains a redline of the draft 2017 RPS Plan and compares it against PG&E's 2016 RPS Plan. The summary table highlights what PG&E describes as the key differences:

Table B

Summary of Changes to PG&E's 2017 RPS Plan

Reference	Area of Change	Summary of Change	Justification
Section 9.4	New Section of Plan	RPS Sales Lessons Learned PG&E has identified a number of best practices to incorporate for future solicitations.	Ruling at 14.
Section 1	Consideration of 55% RPS Target	As part of PG&E's proposal for the orderly retirement of the Diablo Canyon Power Plant, it has proposed as part of the IRP to adopt a voluntary commitment to provide 55% RPS energy beginning in 2031. This voluntary 55% target is included in PG&E's RPS position modeling for planning purposes, but is subject to CPUC approval.	Ruling at 9-10

[36] *Id.*, at 71.

7.13. Safety Considerations[37]

To the extent that PG&E builds, operates, maintains, and decommissions its own RPS-eligible generation facilities, PG&E claims it follows its internal standard protocols and practices to ensure public, workplace, and contractor safety. These standards include the Employee Code of Conduct, Safety Commitment, Personal Safety Commitment, and Keys to Life. PG&E also claims that it operates each of its generation facilities in compliance with all local, state and federal permit and operating requirements such as state and federal Occupational Safety and Health Administration (OSHA) and the Commission's General Order 167. PG&E claims to do this by using internal controls to help manage the operations and maintenance of its generation facilities, including: (1) guidance documents; (2) operations reviews; (3) an incident reporting process; (4) a corrective action program; (5) an outage planning and scheduling process; (6) a project management process; and (7) a design change process.

With respect to third-party owned, RPS eligible facilities, PG&E states it developed additional contract provisions to reinforce the developer's obligations to operate in accordance with all applicable safety laws, rules and regulations as well as Prudent Electrical Practices.[38] PG&E states it receives monthly progress reports from generators who are developing new RPS-eligible resources where the output will be sold to PG&E. As part of this progress report, generators are required to provide the status of construction activities, including OSHA recordables and work stoppage information.

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[37] *Id.*, at 72.

[38] *Id*, at 75-76.

7.14. RPS Position Management and Sales of Surplus RPS Products[39]

Given its forecasted long position, PG&E proposes and requests approval of a framework through which to assess whether to hold or sell excess bankable RPS volumes, as detailed in Appendix J and first approved in D.16-12-044. PG&E expects to hold one or more solicitations for the sale of RPS-eligible generation and associated RECs in 2017. PG&E may also consider entering into bilateral contracts but would seek additional approval from the Commission under those circumstances. PG&E anticipates selling short-term products, and may consider longer term offers in the future. PG&E states it expects minimal negotiations with respect to the form agreement and proposes that these sales agreements be filed as Tier 1 Advice Letters for Commission approval.

8. SCE 2017 RPS Plan

8.1. Summary

In its 2017 RPS Plan, SCE proposes not to hold a solicitation because it forecasts no need for new eligible resources for the foreseeable future. SCE proposes instead to sell RPS-eligible generation and associated RECs, as described in Appendices F.1 and F.2 of its 2017 RPS Plan.

8.2. Assessment of RPS Portfolio Supplies and Demand[40]

8.2.1. Renewables Portfolio

For the first compliance period from 2011 through 2013, SCE reports that it served 20.7% of its retail sales from RPS-eligible resources. In 2014, SCE reports that it served 23.4% of its retail sales from RPS--eligible resources. In 2015, SCE reports that it served 24.3% of its retail sales from RPS-eligible resources. In

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[39] *Id.* at 77.

[40] SCE 2017 RPS Procurement Plan at 5 (July 21, 2017).

2016, SCE reports that it served 28.2% of its retail sales from RPS-eligible resources.

SCE described its recent RPS contracting activity during 2016 and through June of 2017. From the 2015 RPS solicitation, SCE claims it signed 2 contracts for 253 MW, 12 ReMAT contracts for approximately 23 MW, 3 Bio-RAM contracts for 67 MW, 2 GTSR contracts for 40 MW, and 3 QF standard offer contracts for approximately 11 MW in 2016 and through June of 2017.

8.2.2. Renewable Procurement Need

Appendices C.1 through C.4 to SCE's 2017 RPS Plan include SCE's forecast of its renewable procurement position and need – *i.e.,* SCE's RNS – based on the RPS targets adopted by the Commission in D.11-12-020 for all years through 2020, as well as the RPS targets adopted by the Commission in D.16-12-040 for the years 2021 to 2030. Appendices C.1 through C.4 also demonstrate that using either SCE's or the Commission's assumptions, SCE forecasts sufficient resources to meet procurement quantity requirement for the second compliance period. SCE forecasts a net short position in the year 2030 with the use of bank under the Commission's assumptions. But SCE forecasts a net long position in the year 2030 with the use of bank under SCE's assumptions. Under the 50% by 2030 target and using SCE's assumptions, SCE forecasts a net short position starting in 2027 without the use of bank (as shown in Appendix C.2). But with the use of bank, SCE forecasts a net long position at the end of 2030 (as shown in Appendix C.4). Using the Commission's assumptions, SCE forecasts a net short position starting in 2024 without the use of bank and a net short position starting in 2030 with the use of bank. As such, in SCE's estimation, it does not have a current need for additional RPS-eligible energy.

Instead, SCE will seek to sell RECs of 2017-2020 vintage to allow SCE to optimize its renewables portfolio and provide value for all bundled and to unbundled customers. SCE may conduct a solicitation of offers, negotiate bilaterally, or bid into other parties' solicitations to sell such products to maximize value to customers and optimize the RPS portfolio.

8.2.3. **Lessons Learned**[41]

SCE sees a possible future trend toward departing load as it expects additional cities within its service territory to join Lancaster and Apple Valley in developing a CCA program in their local jurisdiction. SCE does not believe that the departing load should have an impact on procurement activities unless load-serving entities formalize their departure through a Binding Notice of Intent, an Initial Resource Adequacy filing, or the start of CCA service.

SCE also believes it can create short term customer value and introduce some degree of rate stability by engaging in limited amount short term sales transactions. An open market for short term REC sales may, in SCE's estimation, provide for a low cost option for RPS compliance.

8.3. Project Development Status Update[42]

Appendix B to SCE's 2017 RPS Plan contains a status update on the development of RPS-eligible projects currently under contract, but not yet delivering generation.

8.4. Potential Compliance Delays[43]

SCE identifies five factors that may challenge its achievement of the RPS goals: (1) curtailment; (2) the increasing proportion of intermittent resources in SCE's renewables portfolio; (3) permitting, siting, approval, and construction of

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[41] *Id.*, at 16-18.

[42] *Id.*, at 19.

[43] *Id.*.

both renewable generation projects and transmission; (4) a heavily subscribed interconnection queue; and (5) developer performance issues. Each one of these factors is discussed in its 2017 RPS Plan.[44]

8.5. Risk Assessment[45]

SCE states that it accounts for potential issues that could delay RPS compliance, project development status, minimum margin of procurement, and other potential risks through the use of probabilistic risk-adjusted success rates for energy deliveries from contracts that are executed but not yet online. SCE considers these risk factors in this process. Additionally, SCE says it takes into account historic generation from existing resources, including lower than expected generation, variable generation, and resource availability, among other factors, when forecasting expected generation from its contracted renewable projects. The quantitative analysis provided in Appendices C.1 through C.4 of SCE's 2017 RPS Plan reflects these considerations.

8.6. Quantitative Information[46]

According to SCE, Appendices C.1 through C.4 include SCE's RNS calculations using the standardized reporting template included in the RNS Ruling under the RPS program rules. As required by the Commission's RNS Methodology, Appendices C.1 and C.2 include physical RNS calculations and Appendices C.3 and C.4 include optimized RNS calculations.

Appendices C.2 and C.4 include SCE's physical RNS and optimized RNS through 2030, based on the following SCE assumptions:[47]

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[44] *Id.*, at 19-23.

[45] *Id.*, at 28.

[46] *Id.*, at 24.

- SCE's most recent bundled retail sales forecast for 2017 through 2030 which excludes Green Rate customers under SCE's GTSR program;
- Transfers of energy deliveries from SCE's interim pool of RPS eligible resources to the Green Rate program to serve Green Rate customers until dedicated Green Rate resources come online; and conversely, transfers of energy deliveries from dedicated Green Rate resource that are not used by Green Rate customers;
- Contracted projects that are currently online will deliver 100% of their expected amount of renewable energy;
- Probabilistic risk-adjusted success rates for energy deliveries from contracted projects that are not yet online. SCE's forecasts include individual project-specific, risk-adjusted success rates for large, near-term projects and a flat 60% success rate for the remaining projects, which is based on these projects' overall weighted average success rate; and
- 100% success rate for projects originating from pre-approved programs such as ReMAT and BioMAT before contracts from such programs are signed.

Appendices C.1 and C.3 provide SCE's physical and optimized RNS through 2030 using the Commission's RNS Methodology. Appendices C.1 and C.3 use the same assumptions as in Appendices C.2 and C.4 except that:

- Instead of using SCE's most recent bundled retail sales forecast for all years, they use SCE's most recent bundled retail sales forecast for 2017 through 2021 and the CEC's 2016 California Energy Demand Updated (CEDU) forecast for 2022-2027 with extension beyond 2027 calculated based

[47] The physical RNS shows SCE's RPS position without the use of its bank, and the optimized RNS shows SCE's RPS position with the use of its bank.

on the average annual rate of change in the CEDU Forecast for the period 2015-2027.

At this time, SCE states it does not propose including a VMOP in its renewable procurement planning. SCE will account for RPS need forecasting risks through the identification and forecast of RECs above its RPS procurement quantity requirements based on its forecast RPS portfolio.

8.7. Minimum Margin of Procurement[48]

SCE states that its renewable procurement efforts will be guided by its forecast of its renewable procurement needs, as provided in Appendices C.1 through C.4 to its 2017 RPS Plan.

In its forecast of its renewable procurement position and need, SCE currently accounts for the risks of project failure and delay associated with contracted projects that are not yet online. To this end, SCE uses individual project-specific, risk-adjusted success rates for large, near-term projects and a flat 60% success rate for the remaining projects, which is based on these projects' overall weighted average success rate.

SCE asks that the Commission rely on retail sellers to calculate their minimum margins of procurement and should not attempt to impose a one-size-fits-all approach. As many of the projects in SCE's portfolio become operational, SCE believes that it will face different risks, including integration of these resources. The risks associated with project failure will be replaced by less significant risks of projects generating below full capacity. Similarly, SCE expects that the portfolio risk picture is not the same for each retail seller. For example, risks may vary depending on whether a portfolio contains a high

[48] SCE's 2017 RPS Procurement Plan at 31.

proportion of contracts that are online or depending on the various technologies being used (*e.g.*, geothermal technology, which is a baseload resource, versus wind or solar technologies, which are more intermittent). For these reasons, SCE suggests that each retail seller should continue to have the authority to revise its approach to calculating the minimum margin of procurement through the RPS procurement planning process and each retail seller should have the flexibility to calculate this margin based on its unique portfolio make-up and procurement needs.

8.8. Bid Solicitation Protocol, Including LCBF Methodologies[49]

8.8.1. Bid Solicitation Protocol

SCE proposes to hold a 2017 RPS solicitation, but only for sales of vintage 2017 through 2020 renewable energy for Category 1 RECs. SCE proposes and requests approval of a framework through which to assess whether to hold or sell excess bankable RPS volumes, detailed in Appendix F.2. SCE seeks approval for short-term REC sales through the following transaction methods: competitive solicitations, bilateral transactions, brokers, and exchanges. SCE seeks pre-approval of a list of brokers and exchanges, contained in Appendix F.1, and proposes to obtain Commission approval to add or use other brokers in the future by filing a Tier 2 Advice Letter. Regarding Commission oversight of the sales, SCE proposes a pre-approval mechanism similar to the one used under the Bundled Procurement Plans for non-renewable energy. Alternatively, SCE seeks approval of a Tier 1 Advice Letter process consistent with previous Commission decisions on the RPS Plans.[50]

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[49] *Id.*, at 32.

[50] D.14-11-042; D.16-12-044.

For its REC sales solicitation, SCE will use the proposed 2017 Procurement Protocol included at Appendix I.1 of its 2017 RPS Plan.

8.9. Economic Curtailment, Frequency, Costs, and Forecasting[51]

SCE plans to bid resources with economic curtailment rights into the day-ahead and real-time markets. Resources with these curtailment rights will then be curtailed as needed based on CAISO's economic dispatch. In some SCE PPAs, there is a pre-defined amount of pre-paid energy per year that may be economically curtailed, subject to some restrictions, without requiring SCE to pay for the energy that could have been delivered but for the curtailment instruction. This amount is commonly referred to as a "curtailment cap." Once the curtailment cap is reached, SCE must pay the contract price for energy that could have been delivered but for the curtailment instruction. In other SCE PPAs, SCE claims it has the right to curtail based on economic factors, but must always pay the contract price for energy that could have been delivered but for the curtailment instruction. These types of curtailment rights are commonly referred to as "take-or-pay." In instances where SCE has either exceeded the curtailment cap or only has "take-or-pay" economic curtailment rights to begin with, if SCE were not to curtail deliveries in excess of any schedules awarded at positive prices, customers would pay the contract price for that excess delivered energy and incur the costs associated with negative pricing in such intervals. SCE's economic bids will therefore serve to further limit customer exposure to negative prices both day-ahead and in real-time, even if SCE ultimately pays the contract price for curtailed energy.

[51] SCE's 2017 RPS Procurement Plan at 34.

8.10. Expiring Contracts[52]

For SCE's RPS-eligible contracts expiring in the next ten years, Appendix E to SCE's 2017 RPS Plan includes the name of the facility, technology, contract expiration date, nameplate capacity, expected annual generation, location, contract type, and portfolio content category classification.

8.11. Cost Quantification[53]

The spreadsheet attached as Appendix D to SCE's 2017 RPS Plan includes actual expenditures per year for RPS-eligible generation for every year from 2003 through 2016, as well as actual RPS-eligible generation for every year from 2003 through 2016. Appendix D also includes a forecast of future expenditures SCE may incur every year from 2017 through 2030, as well as a forecast of expected generation for every year from 2017 through 2030.

8.12. Important Changes from 2016 RPS Plan[54]

SCE states that its 2017 RPS Plan includes changes to: (1) SCE's 2016 Procurement Protocol; (2) SCE's 2016 *Pro Forma*; (3) SCE's 2016 *Pro Forma* REC Sales Agreement; and (4) SCE's LCBF Methodology. While there is a redline of the changes at Appendices I.2, G.2, J.2, and H.2, the chart below summarizes the changes:

Topic	2017 RPS Plan
Changes to 2017 Procurement Protocol	SCE plans to solicit offers for SCE to sell RECs of 2017-2020 vintage as part of any 2017 RPS solicitation that it may hold. The 2017 RPS Procurement Protocol, in Article 1, includes solicitation of proposals to sell RECs of

52 *Id.*, at 48.

53 *Id.*

54 *Id.*

Topic	2017 RPS Plan
	2017-2020 vintage which may be part of any 2017 RPS solicitation.
Changes in 2017 *Pro Forma*	1. In case of shortfall in the actual installed Contract Capacity or Installed DC Rating, Seller can pay for the capacity shortfall, in addition to the option of applying Development Security. This payment option helps protect Seller's relationship with its Letter of Credit issuing bank. This change is reflected in Section 3.06(f). 2. Interest payment on cash collateral is changed from monthly payment upon receiving invoice to payment upon collateral return. This change saves administrative efforts for both parties. This change is reflected in Section 8.04(a). 3. Development Security posting deadline is changed from Effective Date to within five Business Days following Effective Date. The change provides Seller reasonable time to post the security. This change is reflected in Section 8.02(b).
Changes in *2017 Pro Forma* REC Sales Agreement	The credit and collateral terms were updated to reflect a revised method for calculating the buyer's collateral requirements. The confidentiality provisions were modified to allow the parties to disclose confidential information to the Western Renewable Generation Information System (WREGIS).
Changes in LCBF Methodology	SCE will use the Effective Load Carrying Capacity (ELCC) methodology with approved ELCC values from Energy Division's second proposed methodology, as set forth in Appendix A of D.17-06-027 to calculate Resource Adequacy benefit.

8.13. Safety Considerations[55]

SCE's 2017 *Pro Forma* provides that the seller must operate the generating facility in accordance with "Prudent Electrical Practices." The detailed definition of "Prudent Electrical Practices" includes "those practices, methods and acts that would be implemented and followed by prudent operators of electric energy generating facilities in the Western United States, similar to the Generating Facility, during the relevant time period, which practices, methods and acts, in the exercise of prudent and responsible professional judgment in the light of the facts known or that should reasonably have been known at the time the decision was made, could reasonably have been expected to accomplish the desired result consistent with good business practices, reliability and safety. . . ."

SCE's 2017 *Pro Forma* also provides that, prior to commencement of any construction activities on the project site, the seller must provide to SCE a report from an independent engineer certifying that seller has a written plan for the safe construction and operation of the generating facility in accordance with Prudent Electrical Practices.

SCE also has a safety section in its 2017 Procurement Protocol providing that sellers must possess a written plan for the safe construction and operation of the generating facility as set forth in the 2017 *Pro Forma*.

8.14. Standard Contract Option[56]

SCE plans to include a Standard Contract Option PPA as part of the Community Renewables program described below. SCE hopes that that Standard Contract Option will allow for rapid development of renewable

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[55] *Id.* at 51.

[56] *Id.*, at 52.

projects by avoiding the contract negotiation process and expediting the Commission's approval process. Once executed, the Standard Contract Option PPAs will be submitted to the Commission for approval via Tier 2 advice letter.[57]

8.15. GTSR Program[58]

The GTSR program structure approved by the Commission consists of two elements: (1) a green tariff option (called the "Green Rate" by SCE) allowing customers to purchase energy with a greater share of renewables, and (2) an enhanced community renewables option (called the "Community Renewables" or "CR" program by SCE) allowing customers to subscribe to renewable energy from community-based projects.

With regard to the Green Rate, SCE claims it has already procured its 50 MW advance procurement requirement in its 2015 RPS solicitation. SCE does not anticipate doing additional Green Rate procurement because the Green Rate program currently has a limited number subscribed customers and SCE expects its advance procurement to satisfy initial customer enrollment.

8.16. Other RPS Planning Considerations and Issues[59]

8.16.1. TOD Factors

SCE did not propose updated TOD factors. Instead, SCE proposes to wait for the Commission to establish new time-of-use (TOU) period definitions though the TOU OIR (R.15-12-012), and then compare them to SCE's long-term power price shapes. If the periods are consistent, SCE will use new TOU period

[57] The Commission authorized the use of the streamlined RAM procurement tool, with a standard contract option, for future RPS solicitations in D.14-11-042, and the Tier 2 Advice Letter approval process is the same process as was used in RAM.

[58] SCE's 2017 RPS Procurement Plan at 54.

[59] *Id.*, at 62.

definitions and calculate TOD factors. If they are not consistent, SCE may develop new definitions and factors based on its long-term power price forecast.

SCE's current TOD factors are as follows:

Table I

SCE's Proposed TOD Factors

	On-Peak	Off-Peak	Super-Off-Peak
Summer	1.35	1.08	0.86
Winter	1.18	1.02	0.86

- On-Peak: HE 15 – HE 20 2pm-8pm (weekends except holidays)
- Off-Peak: HE 9 – HE 14 8am – 2pm (weekdays, weekends, and holidays); HE 15 – HE 20 2pm – 8pm (weekends and holidays); HE 21 – HE 22 (weekdays, weekends, and holidays)
- Super-Off-Peak: HE 23 – HE 8 (weekdays, weekends, and holidays)
- Summer: June 1 – Sept. 30
- Winter: Oct. 1 – May 31

9. SDG&E 2017 RPS Plan

9.1. Summary

SDG&E states that its 2017 RPS Plan describes the processes used to determine its RPS procurement need, as well as the methods it will use to manage its RPS portfolio to meet RPS program compliance targets. SDG&E claims that its RPS Plan establishes guidelines for SDG&E's procurement of LCBF RPS-eligible resources that have enabled and will enable SDG&E to achieve its procurement need in each CP. To determine the quantity of renewable generation that must be procured, SDG&E will follow a Need Determination Methodology which is discussed below.

9.2. Assessment of RPS Portfolio Supplies and Demand[60]

9.2.1. Need Determination Methodology

SDG&E states that it makes procurement decisions based on how its risk-adjusted RPS position forecast (referred to herein as its "RPS position") compares to its RPS program compliance requirements, the result of which is its probability-weighted procurement need or RNS. In order to calculate its RPS position, SDG&E assigns a probability of success, following a qualitative and quantitative assessment, to the expected deliveries for each project that is not yet online in its portfolio and then adds the risk-adjusted expected deliveries across all projects in its entire RPS portfolio.

SDG&E then assesses the compliance needs for each compliance period. For CP1, the compliance determination process is not yet complete. For CP2 (2014 – 2016), SDG&E expects that it will meet its CP2 RPS goals with generation from contracts that have been executed, together with the deliveries from utility-owned generation (UOG) initiatives where relevant progress has been made. With respect to CP3 (2017 – 2020), in light of the current probability-weighted RPS position forecast, it is possible that SDG&E will not require additional procurement. As for the post-2020 period, SDG&E states it anticipates meeting its RPS requirements for each CP through 2030 with procurement already under contract. As such, SDG&E will not hold a 2017 RPS solicitation.

9.2.2. Portfolio Optimization Strategy

SDG&E says it employs an optimization strategy, wherein the probability of success of each of the projects in SDG&E's portfolio is revised monthly in an

[60] SDG&E 2017 RPS Procurement Plan at 4 (July 21, 2017).

interdepartmental meeting using the most current information. Generally, if SDG&E were to foresee a shortfall it will then procure additional resources; if it foresees an excess then it will seek to sell a portion or all of this excess pending the results of a detailed cost and benefit analysis of banking versus selling. Once SDG&E has determined its need, it proceeds to manage its procurement by continually reviewing its portfolio to minimize costs, maximize value and manage risk.

Given SDG&E's forecasted long RPS position, SDG&E proposes and requests approval of a framework through which to assess whether to hold or sell excess bankable RPS volumes, detailed in Appendix 10.B. SDG&E proposes energy and REC sales with terms of 1 month to 10 years through competitive solicitations or bilateral transactions.

9.2.3. Lessons Learned

SDG&E first discusses overbuilding and its impact on ratepayers. For the past four years, SDG&E states it has been concerned that developers have provided profiles in prior solicitations that ultimately do not match the profiles of the facilities that are built. In other words, developers have "overbuilt" facilities (*i.e.*, installed capacity above the amount bid and/or shaped the production profile to take advantage of higher-priced TOD periods). The resulting over generation has increased costs to customers through increased contract costs, and increased generation overall which increases the incidence of and payments for negative real-time energy pricing. In response to this observation, SDG&E modified its PPA to include a maximum limit on generation during each TOD period, which the Commission approved as a part of SDG&E's 2013 RPS Plan. SDG&E also made several changes to its PPA in its 2015 RPS Plan in an effort to address overbuilding through stronger generation caps.

SDG&E raised two issues as "lessons learned," both of which are the result of increasing volumes of intermittent, renewable resources developed in recent years and the impact on California energy markets.

First, SDG&E described how the time of day when peak demand for electricity occurs has moved to later in the afternoon, which it terms Peak Shifting. As a result of the RPS program, solar and wind energy has been added to the grid, and much more appears likely to come online before 2020. These renewable resources are low variable cost resources that (at high penetration levels) will cause reductions in marginal prices in periods when they operate. Amounts of rooftop solar are also being added by customers behind the meter. A large amount of variable resource penetration during any single time during the day may result in decreases in marginal energy prices and even ramping events. As a result of increased renewable generation in Southern California, the peak load net of variable energy resources has shifted and will continue to shift as the California resource portfolio evolves. As market conditions develop, SDG&E stresses that it is important that SDG&E's TOD factors and time periods, which will be used for analysis purposes, reflect the most up-to-date information to provide ratepayers with the greatest value. SDG&E updated its TOD periods in its 2013 RPS Plan, as well as the TOD factors based on the market conditions, to reflect the shift in timing and magnitude of energy and capacity and will continue to do so as market conditions change. SDG&E's LCBF document, attached to its 2017 RPS Plan as Appendix 9, includes the most recent TOD factors which were calculated as of June 2017. SDG&E's TOD factors are as follows:

Table 2

SDG&E's Proposed Local Full Capacity Deliverability Status (FCDS)

TOD Factors and Periods[61]

	On-Peak	Semi-Peak	Off-Peak
Summer	1.943	0.819	0.963
Winter	2.638	0.541	0.823

- Summer On-Peak: July 1 – Oct. 31 (HE 15 – HE 21 weekdays)
- Summer Semi-Peak: July 1 – Oct. 31 (HE 7 – HE 22 weekdays excluding Summer On-Peak hours)
- Summer Off-Peak: July 1 – Oct. 31 (all weekend hours, NERC Holiday Hours, and weekday hours not considered Summer On-Peak or Summer Semi-Peak)
- Winter On-Peak: Nov. 1 – June 30 (HE 18 – HE 21 weekdays)
- Winter Semi-Peak: Nov. 1 – June 30 (HE 7 – HE 22 weekdays excluding Winter On-Peak hours)
- Winter Off-Peak: Nov. 1 – June 30 (all weekend hours, North American Electric Reliability Corporation (NERC) Holiday Hours, and weekday hours not considered Winter On-Peak or Winter Semi-Peak)

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[61] SDG&E's previously approved Local FCDS TOD factors were the following:

	On-Peak	Semi-Peak	Off-Peak
Summer	2.304	1.204	0.853
Winter	1.495	0.866	0.746

Id., at appx. 13, p. 47-48.

Table 3

SDG&E's Proposed System and Imperial Valley FCDS TOD Factors and Periods[62]

	On-Peak	Semi-Peak	Off-Peak
Summer	1.841	0.792	0.967
Winter	2.639	0.550	0.841

Table 4

SDG&E's Proposed Energy Only TOD Factors and Periods[63]

	On-Peak	Semi-Peak	Off-Peak
Summer	1.714	0.758	0.971
Winter	2.641	0.562	0.864

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[62] SDG&E's previously approved System and Imperial Valley FCDS TOD factors were the following:

	On-Peak	Semi-Peak	Off-Peak
Summer	1.927	0.958	0.869
Winter	1.464	0.948	0.827

Id.

[63] SDG&E's previously approved Energy Only TOD factors were the following:

	On-Peak	Semi-Peak	Off-Peak
Summer	1.581	0.957	0.896
Winter	1.509	0.977	0.853

Id.

9.3. Project Development Status Update[64]

SDG&E states it evaluates project development status to assess each project's ability to begin deliveries pursuant to contract terms and conditions. SDG&E's portfolio of renewable energy resources currently under contract but not yet delivering (either pre-construction or in construction) are in various stages of development. SDG&E has or is developing contracts for three renewable projects that are in the pre-construction or construction phase (of which one is UOG) and 62 projects that are in commercial operation (none of which are UOG). In Appendix 1 to its 2017 RPS Plan, SDG&E provides its most recent information on its developing projects from its June, 2017 Procurement Review Group (PRG) meeting.

9.4. Potential Compliance Delays[65]

Similar to prior RPS procurement plans, SDG&E identifies seven potential factors that can impact project development and the eventual attainment of RPS program goals: (1) transmission and permitting; (2) project finance, tax equity financing, and government incentives; (3) debt equivalence and accounting; (4) regulatory factors affecting procurement; (5) unanticipated curtailment; (6) insufficient supply of renewable resources; and (7) unanticipated increases in retail sales. SDG&E states that these factors contribute to SDG&E's monthly assessment of the likelihood of each project's success. For example, a project that has been experiencing difficulty in obtaining a key permit would receive a probability weighting reduction to account for this risk until the issue is resolved. While the impacts of the regulatory proceedings cannot be known

[64] *Id.* at 38.

[65] *Id.*, at 40.

until the final decisions are issued, SDG&E states it is monitoring these issues and will reflect their outcomes accordingly, when appropriate. The results of these cumulative assessments are reflected in the RNS, which helps SDG&E to identify any potential project delays that may impact compliance and to then plan its procurement activities over the next two compliance periods and past 2020. The RNS as of June 2017 is provided in Appendix 2 to SDG&E 2017 RPS Plan.

9.5. Risk Assessment[66]

Similar to prior RPS procurement plans, SDG&E identified several "dynamic factors" outside of SDG&E's control that could impede progress towards achieving RPS goals. SDG&E described the risk factors as the intermittent nature of many renewable resources, regulatory changes related to renewable project financing, and technological challenges with older or new technologies, as well as, the CAISO and WREGIS, which are essential for buying and selling electricity and RECs.

The analysis attached in Appendix 2 to SDG&E's 2017 RPS Plan shows the Commission's prescribed RNS calculation with supporting probability weighting calculations by project as of June 2017.

9.6. Minimum Margin of Over-Procurement[67]

SDG&E's RPS Risk Adjusted RNS Calculation, as shown in Appendix 2 to SDG&E's 2016 RPS Plan, provides a VMOP. SDG&E's VMOP is composed of a "Minimum Margin of Procurement" that is intended to account for foreseeable project failures or delays, as well as an additional volume of procurement which

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[66] *Id.*, at 50.

[67] *Id.*

is undertaken to ensure that SDG&E achieves its RPS requirements despite unforeseeable risks. Due to fluctuations in RPS targets (as a result of changes in retail sales) and RPS deliveries, SDG&E believes it is nearly impossible to meet RPS targets with the exact number of MWhs required. SDG&E's VMOP is designed to ensure that it achieves its RPS goals with a "buffer" to and considers foreseeable and unforeseeable risks. Because it is difficult to predict retail sales and project performance, particularly for periods farther into the future, SDG&E's VMOP may be higher in later years. SDG&E's portfolio (RPS resources necessary to reach compliance and provide a VMOP) is the result of the forecasts (including need, retail sales, and project success rates), the assessment of potential risks, and the project valuations made at the time of each individual contract execution and approval.

9.7. Consideration of Price Adjustment Mechanism[68]

SDG&E has incorporated price adjustment mechanisms into some of its current contracts that are intended to alleviate some of these risks, including the following:

- Price adjustment for delay in Guaranteed Commercial Operation Date (GCOD): A lower price for a late GCOD provides an additional incentive for developers to come online pursuant to the contract. However, this structure can create financing challenges if financing parties are not comfortable with the potentially lower price. It is also difficult to quantify an appropriate price adjustment amount and can lead to drawn out negotiations.
- Capped transmission upgrade costs: Placing a cap on the amount of transmission upgrade costs, which are

[68] *Id.* at 55.

ultimately borne by ratepayers, that a project can incur is, in SDG&E's estimation, an effective way to limit ratepayer exposure to such costs. The cap is set as a condition precedent to SDG&E's obligations under the PPA. If estimated costs exceed the cap, SDG&E has the right not to move forward with the PPA.

- <u>Price adjustment for higher than expected transmission upgrade costs</u>: Another mechanism that SDG&E has incorporated into past contracts is a mechanism whereby the seller agrees to a price reduction to offset higher than anticipated transmission upgrade costs. Under this mechanism, the contract price would be reduced on a dollars per megawatt-hour basis commensurate with the cost of transmission upgrades above an agreed upon cap. The price adjustment mechanism would include an upper limit on transmission upgrade costs, above which SDG&E can terminate the contract. This mechanism is similar to the cap described immediately above except, rather than giving SDG&E the right not to move forward with the PPA, it gives the developer the choice of whether to go forward at a reduced price equal to the amount of transmission costs above the cap, or the developer may choose not to go forward with the PPA.
- <u>Price adjustment for failure to achieve full capacity deliverability status</u>: If a project is not deemed fully deliverable by CAISO at the time of COD, then the PPA price is reduced by either a negotiated price reduction specific to the project, or the application of energy only TOD factors in place of FCDS factors until such time as the project is deemed fully deliverable.

9.8. Economic Curtailment Frequency Costs, and Forecasting[69]

In SDG&E's estimation, the issue of curtailment is a result of the operational characteristics of the facilities within the renewable market (both

[69] *Id.*, at 56.

those procured pursuant to the RPS program, as well as customer-side facilities that are incremental to the RPS program under existing rules, specifically net energy metered installations). These resources are as-available (that is, they generate only when the wind is blowing or the when sunlight strikes the panel, and they are negatively affected by atmospherics which interfere with this energy production, such as cloud cover) and intermittent, which results in generation profiles that do not necessarily follow load. SDG&E's net load profile now shows a pronounced shift toward an evening peak as increased solar generation has begun to offset load during SDG&E's historical peak load hours (mid-day). The shift of SDG&E's net peak into the evening hours becomes more pronounced as more renewable generation (particularly solar) is brought online, as it has over the past several years and will continue to do so as RPS penetration increases.

SDG&E states it has been tracking its curtailment actions and results since Q3 2014, and based on the data available to date, its curtailment activities have resulted in cost savings for SDG&E ratepayers. SDG&E will continue to track this data and report on it.

SDG&E also states that it has continued renegotiation of dispatch down, scheduling and curtailment provisions of existing contracts. To the extent feasible, SDG&E plans to address all contracts that require updates due to CAISO's implementation of FERC Order 764, including RAM legacy contracts to the extent the Commission has previously approved such provisions in the most recent RAM VI PPA. SDG&E's PPAs (including RAM legacy contracts) generally contain language which contemplates the need for the buyer and seller to update the PPA when there are major market changes (such as CAISO's implementation of FERC Order 764).

9.9. Expiring Contracts[70]

Appendix 4 to SDG&E's 2017 RPS Plan lists SDG&E's portfolio of contracts as of June 2017 that will expire in the next 10 years, equal to approximately 440 MW of RPS-eligible capacity.

9.10. Cost Quantification[71]

Appendix 3 to SDG&E's 2017 RPS Plan provides an annual summary of both actual and forecasted RPS procurement costs and generation, by technology type, as of June 2017.

9.11. Imperial Valley

SDG&E provided an update on its existing contracts with facilities located in the Imperial Valley. SDG&E reports that its RPS portfolio contains contracts with 11 facilities in the Imperial Valley(IV)/Imperial Irrigation District territory, that when completed will provide an estimated 3,100 GWh per year. As of June 2017, 10 of these projects have reached commercial operation. Additionally, projects located within IV and either directly connected or dynamically transferred via pseudo-tie into SDG&E's service territory by the CAISO are eligible to participate in SDG&E's GTSR program.[72]

9.12. Important Changes to the 2017 RPS Plan[73]

Appendix 5 to SDG&E's 2017 RPS Plan detail the important changes made to the following sections of its 2017 RPS Plan: plan structure, assessment of RPS portfolio supplies and demand, portfolio optimization strategy, lessons learned

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[70] *Id.*, at 61.

[71] *Id.*, at 61.

[72] Advice Letter 2717-E (June 11, 2015).

[73] SDG&E's 2017 RPS Procurement Plan at 62.

and trends, project development status update, potential compliance delays, risk assessment, quantitative information, bid solicitation protocol including least-cost, best-fit, economic curtailment, California tree mortality emergency proclamation, expiring contracts, cost quantification, safety considerations, RAM, GTSR, RPS long-term model PPA, RPS short-term model PPA, RPS REC agreement, LCBF, RPS sales RFP, RPS sales model PPA, framework for assessing potential RPS sales GT RAM RFO. GT RAM PPA, GT RAM project description form, GT RAM offer form, ECR RAM RFO, ECR RAM PPA rider, ECR RAM project description form, and ECR RAM offer form.

9.13. Safety Considerations[74]

SDG&E's RPS PPAs have the following provisions that are designed to incorporate safety considerations into its decision-making process and operations: good industry practice; annual capacity testing, general operation; meeting CAISO and WECC standards; meeting reliability standards; performance of testing and calibration of the electric meters; scheduling of planned outages; completion and submission of quarterly progress reports that address all accidents, work stoppages, and their impact on project construction.

SDG&E's PPA provisions include standard of care; access rights; safety plan; demonstrated contract capacity; and prudent electrical practices.

SDG&E requires all contractors working on UOG projects to observe safety requirements and safety inspections and reporting protocols that are summarized in the 2017 RPS Plan.

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[74] *Id.*

9.14. Renewable Auction Mechanism[75]

As for procurement need, SDG&E states it may use the RAM solicitation documentation, attached as Appendices 11-12.B to SDG&E's 2017 RPS Plan, on an as-needed basis to procure for its GTSR program. The RAM documentation SDG&E attached is intended for procurement of resources for the GT component of SDG&E's GTSR program, as well as for the ECR component of SDG&E's GTSR program.

9.15. Green Tariff Shared Renewables Program[76]

Pursuant to D.15-01-051, SDG&E filed a Tier 1 AL describing its advanced procurement plan on February 23, 2015, which became effective on February 25, 2015. This AL explained that SDG&E will procure only for GT at this time, stating "SDG&E will seek to procure its authorized initial advanced procurement capacity of between 10.5 MW and 25 MW for SDG&E's GT program as part of SDG&E's RAM VI solicitation." SDG&E also filed a Joint Procurement Implementation AL (JPIAL) in partnership with SCE and PG&E, as well as SDG&E-specific Marketing Implementation (MIAL) and Customer Side Implementation (CSIAL) ALs on May 13, 2015. The Commission issued D.16-05-006 on May 12, 2016, addressing participation of ECR projects in the RAM and other refinements to the GTSR program. Pursuant to that decision, SDG&E filed a Tier 2 AL on June 15, 2016 submitting a revised ECR rider and solicitation documents to allow for procurement of ECR projects using the RAM.

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[75] *Id.*, at 78.

[76] *Id.*, at 80.

10. Comments on the 2017 RPS Plans

As noted above, a number of parties submitted opening and reply comments on the 2017 RPS Procurement Plans. Many parties commented on whether or not the Commission should order additional RPS procurement beyond that necessary to meet the LSEs' current compliance obligations. Parties argued that early procurement of RPS-eligible resources would be more cost-effective due to the declining federal tax credits.[77] Other parties conversely argued that the IOUs have a surplus of resources under contract to meet RPS procurement requirements and that any questions concerning advanced procurement should be investigated in the IRP proceeding.[78] Parties also commented on the need for the Commission to both complete the review and determination of LSEs' compliance with the first compliance period (2011 – 2013) and implement an RPS Procurement Expenditure Limitation.[79] The Commission is currently reviewing both the LSEs' compliance filings and options for implementing the Procurement Expenditure Limitation, though we do not necessarily agree that completing these activities is a predicate to reaching a decision on the merits of requiring additional RPS procurement.

Parties correctly point out that the consideration of near-term or advanced procurement is raised both here in the RPS proceeding and the IRP proceeding

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77 *See, e.g.*, Independent Energy Producers Association Comments at 3-11; Large-Scale Solar Association at 1-12.

78 *See, e.g.*, ORA Reply Comments at 2-6, 8-9; PG&E Reply Comments at 1-7.

79 *See, e.g.*, ORA Comments at 2, 7-8; SCE Reply Comments at 6-7; SDG&E Reply Comments at 9.

(R.16-02-007).[80] We appreciate the urgency as well as the caution expressed by the parties on this issue. While we take no action in this decision, the Commission is closely examining the potential pros and cons of near-term procurement.

11. Conclusion Regarding the Investor-Owned Utilities' 2017 Procurement Plans

11.1. PG&E's 2017 RPS Plans

We find that PG&E's 2017 RPS Plan satisfies the specific requirement for the 2017 RPS Procurement Plans, which were set forth in the *2017 ACR*, and PG&E's evaluation of its current RPS procurement needs relative to its request not to hold a 2017 solicitation to be reasonable. Should PG&E determine that an RPS solicitation or bilateral contracts are needed during the time period covered by the 2017 solicitation cycle, or prior to the Commission issuing a decision on the 2018 RPS Procurement Plans, PG&E is directed to first seek Commission permission in a manner consistent with the Commission's Rules of Practice and Procedure. The authorization granted in this decision solely exempts PG&E from the annual solicitation requirement for the year of 2017.

We find PG&E's framework to assess whether to hold or sell excess RPS volumes to be reasonable. PG&E is authorized to conduct solicitations for the short-term, meaning 5 years or less, sales of RPS volumes during the timeframe covered by its 2017 RPS Plan.[81] PG&E must submit a Tier 1 Advice Letter for

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[80] The potential value of near-term renewable procurement was discussed during an all-party meeting in the IRP proceeding (November 2, 2017). Materials for the all-party meeting are available here: http://www.cpuc.ca.gov/General.aspx?id=6442451195.

[81] Solicitations must comply with all relevant Commission decisions, including D.11-12-052, which prohibits the transfer of Portfolio Content Category 1 and 2 RECs generated prior to the effective date of the contract. For the IOUs, this is the date that Commission approval of the contract is final.

Commission approval of the transactions. PG&E may also engage in bilateral transactions to sell RPS volumes, subject to the Commission's review and approval of completed transactions through a Tier 3 Advice Letter process, as established in D.09-06-050.

Finally, PG&E's updated TOD factors are approved. If PG&E would like to use its updated TOD factors for new procurement in other RPS procurement programs it may request such change consistent with D.14-11-042.

11.2. SCE's 2017 RPS Plans

We find that SCE's 2017 RPS Plan satisfies the specific requirements for the 2017 RPS Procurement Plans that were set forth in the *2017 ACR*, and SCE's evaluation of its current RPS procurement needs relative to its request not to hold a 2017 solicitation to be reasonable. Should SCE determine that an RPS solicitation or bilateral contracts are needed during the time period covered by the 2017 solicitation cycle, or prior to the Commission issuing a decision on the 2018 RPS Procurement Plans, SCE is directed to first seek Commission permission in a manner consistent with the Commission's Rules of Practice and Procedure. The authorization granted in this decision solely exempts SCE from the annual solicitation requirement for the year of 2017.

We find SCE's framework to assess whether to hold or sell excess RPS volumes to be reasonable. SCE is authorized to conduct solicitations for the short-term, meaning 5 years or less, sales of RPS volumes during the timeframe covered by its 2017 RPS Plan.[82] SCE must submit a Tier 1 Advice Letter for

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[82] Solicitations must comply with all relevant Commission decisions, including D.11-12-052, which prohibits the transfer of Portfolio Content Category 1 and 2 RECs generated prior to the effective date of the contract. For the IOUs, this is the date that Commission approval of the contract is final.

Commission approval of the transactions. SCE has not provided sufficient justification for departing from the Commission's reasoning in D.14-11-042, which declined to authorize a *fast track* process but instead authorized Tier 1 Advice Letter filings for short-term RPS transactions. Therefore, in this decision, the Commission only approves SCE's alternative Tier 1 Advice Letter process. SCE may also engage in bilateral transactions to sell RPS volumes, subject to the Commission's review and approval of completed transactions through a Tier 3 Advice Letter process, as established in D.09-06-050.

Finally, SCE may update its TOD factors by filing a motion to update its 2017 RPS Procurement Plan. If SCE would like to use its updated TOD factors for new procurement in other RPS procurement programs it may request such change consistent with D.14-11-042.

11.3. SDG&E's 2017 RPS Plan

We find that SDG&E's 2017 RPS Plan satisfies the specific requirement for 2016 RPS Plans that were set forth in the *2017 ACR*, and that SDG&E's evaluation of its current RPS procurement needs relative to its request not to hold a 2017 solicitation to be reasonable. Should SDG&E determine that an RPS solicitation or bilateral contracts are needed during the time period covered by the 2017 solicitation cycle, or prior to the Commission issuing a decision on the 2018 RPS Procurement Plans, SDG&E is directed to first seek Commission permission in a manner consistent with the Commission's Rules of Practice and Procedure. The authorization granted in this decision solely exempts SDG&E from the annual solicitation requirement for the year of 2017.

We find SDG&E's framework to assess whether to hold or sell excess RPS volumes to be reasonable. SDG&E is authorized to conduct solicitations for the short-term, meaning 5 years or less, sales of RPS volumes during the timeframe covered by its 2017 RPS Plan.[83] SDG&E must submit a Tier 1 Advice Letter for Commission approval of the transactions. If SDG&E also decides to pursue sales with durations greater than 5 years, SDG&E must file a Tier 3 Advice Letter instead of using the expedited Tier 1 Advice Letter process authorized in D.14-11-042 for short-term RPS transactions. SDG&E may also engage in bilateral transactions to sell RPS volumes, subject to the Commission's review and approval of completed transactions through a Tier 3 Advice Letter process, as established in D.09-06-050.

Finally, SDG&E's updated TOD factors are approved. If SDG&E would like to use its updated TOD factors for new procurement in other RPS procurement programs it may request such change consistent with D.14-11-042.

12. Project Development Status Report

In 2006, in order to ensure that the IOUs were making sufficient progress towards meeting their RPS requirements, the Commission created the Project Development Status Report (PDSR) instead of adopting an increased Incremental Procurement Requirement (IPR).[84] The PDSR requirement increased transparency into the IOUs RPS procurement activities, while allowing the IOUs flexibility in fulfilling their procurement targets.[85] Energy Division worked with the IOUs to develop a reporting spreadsheet containing data on RPS projects, including contract details, project development status, technology type, location,

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[83] Solicitations must comply with all relevant Commission decisions, including D.11-12-052, which prohibits the transfer of Portfolio Content Category 1 and 2 RECs generated prior to the effective date of the contract. For the IOUs, this is the date that Commission approval of the contract is final.

[84] D.06-05-039, Conclusion of Law 3(b)(2).

[85] *Id.*, at 23–24.

capacity, financing status, construction start date, commercial online date, regulatory status, and interconnection details.

SB 2 (1X) subsequently replaced the IPR with the Procurement Quantity Requirement (PQR) and codified the requirement for the RPS Plans to include "a status update on the development schedule of all eligible renewable energy resources currently under contract."[86] In D.12-06-038, the Commission reaffirmed mandating PDSRs, which the IOUs have submitted with their annual compliance reports.[87]

In 2012, Energy Division began developing a new reporting tool, the RPS Database, to improve oversight and provide the public with greater access to information on the RPS program. The IOUs provide monthly updates to the RPS Database which contains a larger collection of data on each RPS project than the PDSR. Energy Division uses the RPS Database to monitor IOUs' RPS progress and to report publicly on various aspects of California's RPS program.

Because the IOUs' monthly submissions to the RPS Database contain all the information previously reported through the annual PDSRs, the Commission has determined that the PDSR requirement is no longer necessary. The RPS Database submissions provide more robust information on RPS projects that is in a more useful format and better facilitates public access. Therefore, the IOUs may cease filing PDSRs but must continue to file monthly RPS Database submissions. In order to satisfy Cal. Pub. Util. Code § 399.13(a)(5)(D), the IOUs should reference the RPS Database in their RPS Plans and include a link to the publicly available data published on the Commission's website at

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[86] *See* Cal. Pub. Util. Code §§ 399.13(a)(5)(D), 399.15(b); D.11-12-020.

[87] Ordering Paragraph 35.

http://cpuc.ca.gov/RPS_Reports_Data. Energy Division may continue to work with the IOUs to refine the RPS Database submissions required by this decision.

13. Renewable Auction Mechanism Proposal

As noted above in Section 2, the *2017 ACR* sought comments on a Renewable Auction Mechanism (RAM) proposal. In light of parties' comments and the interplay between the RPS and IRP proceeding, the Commission has decided, for now, not to adopt the RAM proposal. Nevertheless, SDG&E and PG&E must continue to comply with the RAM procurement obligation affirmed in D.17-09-020 and D.17-08-025, respectively.

14. Small and Multi-Jurisdictional Utilities

The small and multi-jurisdictional utilities are Bear Valley, PacifiCorp, and Liberties Utilities (CalPeco). Pursuant to the *2017 ACR*, these utilities were required to, and in fact did, submit RPS procurement plans that provided the information required in Sections 6.1-6.8, and 6.11-6.14 of the *2017 AC*R.

15. Community Choice Aggregators (CCA)

The CCAs are identified in the Summary section of this decision. Pursuant to the *2017 ACR*, these companies were required to, and in fact did, submit RPS procurement plans that provided the information required in Sections 6.1-6.8 and 6.12-6.14 of the *2017 ACR*. None provided the additional cost information requested in Section 6.11.

16. Energy Service Providers (ESP)

The ESPs are identified in the Summary section of this decision. Pursuant to the *2017 ACR*, these companies were required to, and in fact did, submit RPS procurement plans that provided the information required in Sections 6.1-6.8 and 6.12-6.14 of the *2017 ACR*. None provided the additional cost information requested in Section 6.11.

17. Categorization and Need for Hearing

This proposed decision confirms the categorization of this proceeding as ratesetting. This proposed decision modifies the earlier determination that hearings were needed.

18. Comments on Proposed Decision

The proposed decision of ALJs Mason, Simon, and Atamturk in this matter was mailed to the parties in accordance with Pub. Util. Code § 311. Comments were filed on ______________ by ________________.

19. Assignment of Proceeding

Clifford Rechtschaffen is the assigned Commissioner and Anne E. Simon, Robert M. Mason III, and Nilgun Atamturk are the co-assigned ALJs in this proceeding.

Findings of Fact

1. PG&E's, SCE's, and SDG&E's 2017 RPS Procurement Plans do not seek authorization for renewable procurement in excess of SB 350's 50% RPS target.

2. PG&E, SCE, and SDG&E forecast exceeding RPS requirements through at least the 2017-2020 compliance period.

3. PG&E, SCE, and SDG&E do not request to hold RPS solicitations to purchase RPS volumes for the period covered by the 2017 RPS Procurement Plans, or until the Commission issues a decision on the 2018 RPS Procurement Plans.

4. PG&E, SCE, and SDG&E seek authorization to conduct sales solicitations for RPS volumes during the period covered by the 2017 RPS Procurement Plans.

5. All ESPs required to file RPS Procurement Plans in 2017 complied and provided information required under Sections 6.1-6.8 and 6.12-6.14 of the May 26, 2017 Assigned Commissioner Ruling. None of the ESPs submitted

additional cost information as requested in Section 6.11 of the Assigned Commissioner Ruling.

6. All CCAs required to file RPS Procurement Plans in 2017 complied and provided information required under Sections 6.1-6.8 and 6.12-6.14 of the May 26, 2017 Assigned Commissioner Ruling. None of the CCAs submitted additional cost information as requested in Section 6.11 of the Assigned Commissioner Ruling.

7. Bear Valley Electric Service and Liberty Utilities, LLC submitted RPS Procurement Plans providing the information required in Sections 6.1-6.8 and 6.11-6.14 of the May 26, 2017 Assigned Commissioner Ruling.

8. PacifiCorp submitted an IRP providing the information required under Sections 6.1-6.8 and 6.11-6.14 of the May 26, 2017 Assigned Commissioner Ruling.

9. An increase in intermittent renewable generation requires the electric system to be more operationally flexible to ensure adequate system reliability.

10. The IOUs' peak loads are shifting to later in the day.

11. PG&E's, SCE's, and SDG&E's monthly submissions to the RPS Database contain all the information previously reported through the annual Project Development Status Reports.

12. Mansfield Power and Gas, LLC, Tenaska California Energy Marketing, LLC, and Tenaska Power Services Co. are ESPs that do not serve any retail load.

13. Bear Valley Electric Service, PG&E, the Regents of the University of California, SCE, and SDG&E filed motions to update their 2017 RPS Procurement Plans in order to elect early compliance with SB 350's new REC banking rules, which are codified in Pub. Util. Code § 399.13(b) and established in D.17-06-026.

Conclusions of Law

1. Each utility remains responsible for meeting its RPS Program procurement requirements implemented in D.16-12-040.

2. Based on PG&E's, SCE's, and SDG&E's current stated RPS compliance positions, it is reasonable to approve of PG&E's, SCE's, and SDG&E's requests not to hold 2017 RPS solicitations.

3. Due to their long RPS positions through the current 2017-2020 compliance period, it is reasonable to authorize PG&E, SCE, and SDG&E to engage in sales of RPS volumes for the period covered by the 2017 RPS Procurement Plans.

4. The TOD factors presented in PG&E's and SDG&E's 2017 RPS Procurement Plans are reasonable due to shifting demand curves.

5. SCE may submit revised TOD factors by filing a motion to update its 2017 RPS Procurement Plan.

6. The IOUs may use the updated TOD factors in other RPS procurement programs subject to Commission approval through a Tier 1 Advice Letter process.

7. As first established in D.13-11-024, it is reasonable to not require three ESPs, Mansfield Power and Gas, LLC, Tenaska California Energy Marketing, LLC, and Tenaska Power Services Co., to file RPS Procurement Plans because they do not serve retail load.

8. For the fair and efficient administration of the RPS program, it is reasonable to require PG&E, SCE, and SDG&E to file monthly RPS Database submissions in lieu of Project Development Status Reports.

9. The election of Bear Valley Electric Service, PG&E, The Regents of the University of California, SCE, and SDG&E to comply early with SB 350's new REC banking rules should be accepted.

10. All motions for confidential treatment are consistent with Commission decisions and should be granted.

O R D E R

IT IS ORDERED that:

1. Pursuant to the authority provided in Public Utilities Code Section 399.13(a)(1), the draft 2017 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 accepted.

2. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall file Final 2017 Renewables Portfolio Standard Procurement Plans with the Commission within 30 days of the issuance date of this decision.

3. Pursuant to Public Utilities Code Section 365.1(c)(1), the 2017 Renewables Portfolio Standard Procurement Plans filed by the following electric service providers are accepted and deemed final: 3 Phases Renewables, Agera Energy, LLC, American PowerNet Management, LP, Calpine PowerAmerica-CA, LLC, CalPine Energy Solutions, LLC, Commerce Energy of Montana, Inc. (dba Commercial Energy of California), Constellation NewEnergy, Inc., Direct Energy Business LLC, Direct Energy Services, LLC, EDF Industrial Power Services (CA), LLC, EnerCal USA, LLC (dba Yep Energy, Y.E.P.), Gexa Energy California, LLC, Just Energy Solutions, Inc., Liberty Power Holdings, LLC, Palmco Power CA, Pilot Power Group, Inc., Shell Energy North America (US), L.P., The Regents of the University of California, and Tiger Natural Gas, Inc.

4. Pursuant to Public Utilities Code Section 365.1(c)(1), the 2017 Renewables Portfolio Standard (RPS) Procurement Plans filed by the following community

choice aggregators (CCA) are accepted and deemed final: Redwood Coast Energy Authority, Apple Valley Choice Energy, Marin Clean Energy, Pico Rivera Innovative Municipal Energy, Silicon Valley Clean Energy, Sonoma Clean Power Authority, Peninsula Clean Energy, CleanPowerSF, and Lancaster Choice Energy. The following CCAs filed implementation plans but have not yet filed RPS plans: City of San Jacinto (San Jacinto), Monterey Bay Community Power (Monterey), and Valley Clean Energy (Valley Clean). For San Jacinto, Monterey, and Valley Clean, they must file their RPS plans upon registering with the Commission or 90 days prior to delivering load, whichever event occurs first.

5. The 2017 Renewables Portfolio Standard Procurement Plans of Bear Valley Electric Service, PacifiCorp, and Liberty Utilities (CalPeco) are accepted and deemed final.

6. San Diego Gas & Electric Company (SDG&E) is authorized to not hold a 2017 Renewables Portfolio Standard (RPS) solicitation and shall indicate in its Final 2017 RPS Procurement Plans to be filed pursuant to the schedule adopted herein that it will seek permission from the Commission to procure any amounts, other than amounts separately mandated by the Commission (*i.e.*, Feed-In Tariff and Renewable Auction Mechanism, during the time period covered by the 2017 solicitation cycle). This authorization to not hold a solicitation only applies for one year. SDG&E is authorized to conduct solicitations for the short-term, meaning 5 years or less, sales of RPS volumes during the timeframe covered by its 2017 RPS Procurement Plan, or prior to the Commission issuing a decision on the 2018 RPS Procurement Plans. SDG&E must submit a Tier 1 Advice Letter for Commission approval of short-term sales resulting from a solicitation. SDG&E may also engage in bilateral transactions to sell RPS volumes, subject to the Commission's review and approval of completed transactions through a Tier 3

Advice Letter process, as established in D.09-06-050. If SDG&E pursues sales with durations greater than 5 years, SDG&E must file a Tier 3 Advice Letter instead of using the expedited Tier 1 Advice Letter process authorized in D.14-11-042 for short-term RPS transactions. SDG&E shall file a final 2017 RPS Procurement Plan with any updated solicitation materials.

7. Pacific Gas and Electric Company is authorized to not hold a 2017 Renewables Portfolio Standard (RPS) solicitation and shall indicate in its Final 2017 RPS Procurement Plans to be filed pursuant to the schedule adopted herein that it will seek permission from the Commission to procure any amounts, other than amounts separately mandated by the Commission (*i.e.*, Feed-In Tariff and Renewable Auction Mechanism, during the time period covered by the 2017 solicitation cycle.) This authorization to not hold a solicitation only applies for one year. PG&E is authorized to conduct solicitations for the short-term, meaning 5 years or less, sales of RPS volumes during the timeframe covered by its 2017 RPS Procurement Plan, or prior to the Commission issuing a decision on the 2018 RPS Procurement Plans. PG&E must submit a Tier 1 Advice Letter for Commission approval of short-term sales resulting from a solicitation. PG&E may also engage in bilateral transactions to sell RPS volumes, subject to the Commission's review and approval of completed transactions through a Tier 3 Advice Letter process, as established in D.09-06-050. PG&E shall file a final 2017 RPS Procurement Plan with any updated solicitation materials.

8. Southern California Edison is authorized to not hold a 2017 Renewables Portfolio Standard (RPS) solicitation and shall indicate in its Final 2017 RPS Procurement Plans to be filed pursuant to the schedule adopted herein that it will seek permission from the Commission to procure any amounts, other than amounts separately mandated by the Commission (*i.e.*, Feed-In Tariff and Renewable Auction Mechanism, during the time period covered by the

2017 solicitation cycle.) This authorization to not hold a solicitation only applies for one year. SCE is authorized to conduct solicitations for the short-term, meaning 5 years or less, sales of RPS volumes during the timeframe covered by its 2017 RPS Procurement Plan, or prior to the Commission issuing a decision on the 2018 RPS Procurement Plans. SCE must submit a Tier 1 Advice Letter for Commission approval of short-term sales resulting from a solicitation. SCE may also engage in bilateral transactions to sell RPS volumes, subject to the Commission's review and approval of completed transactions through a Tier 3 Advice Letter process, as established in D.09-06-050. SCE shall file a final 2017 RPS Procurement Plan with any updated solicitation materials.

9. In the event Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), or San Diego Gas & Electric Company (SDG&E) decides to hold a 2017 Renewables Portfolio Standard solicitation, PG&E, SCE, or SCE shall first seek permission from this Commission in a manner consistent with the Commission's Rules of Practice and Procedure.

10. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall continue to incorporate and describe how expected economic curtailment affects their Renewables Portfolio Standard (RPS) procurement in future RPS procurement plans.

11. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) may cease filing their Project Development Status Reports but must continue to file monthly Renewables Portfolio Standard (RPS) Database submissions. In order to satisfy Cal. Pub. Util. Code § 399.13(a)(5)(D), PG&E, SCE, and SDG&E must reference the RPS Database in their RPS Procurement Plans and include a link to the publicly available data published on the Commission's website at http://cpuc.ca.gov/RPS_Reports_Data. Energy Division may continue to work

with PG&E, SCE, and SDG&E to refine the RPS Database submissions required by this decision.

12. The following schedule is adopted for the 2017 Renewables Portfolio Standard (RPS) Procurement Plans. Fourteen calendar days after issuance of the decision accepting the 2017 RPS Procurement Plans, Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) shall file final 2017 RPS Procurement Plans. Twenty-one calendar days after issuance of the decision accepting the 2017 RPS Procurement Plans, PG&E, SCE, and SDG&E may launch requests for offers for the IOUs' sales of RPS-eligible products.

13. All motions for confidentiality as to the 2017 Renewables Portfolio Standard Plans are granted.

14. All motions to update the 2017 Renewables Portfolio Standard Procurement Plan are granted.

15. The Motions for Provisional Waiver from Future RPS Compliance Reports are granted in favor of Mansfield Power and Gas, LLC, Tenaska California Energy Marketing, LLC, and Tenaska Power Services Co. as they apply to the RPS procurement plans. The requirement to file annual RPS compliance reports remains unchanged.

16. Rulemaking 15-02-020 remains open.

This order is effective today.

Dated ____________________, at San Francisco, California.

ATTACHMENT A
2017 RPS Plans Acronym List

Acronym	Term
2017 RPS Plan	2017 Renewables Portfolio Standard Procurement Plan
AB	Assembly Bill
ACR	*Assigned Commissioner and Assigned Administrative Law Judge's Ruling Identifying Issues and Schedule of Review of 2017 Renewables Portfolio Standard Procurement Plans* issued May 26, 2017
ADS	Automated Dispatch System
AL	Advice Letter
ALJ	Administrative Law Judge
API	Application Programming Interface
APSA	Approved Project Sponsor Agreement
ASC	Accounting Standards Codification
BioMAT	Bioenergy Market Adjusting Tariff
BioRAM	Tree Mortality RAM
BNI	Binding Notice of Intent
BPP	Bundled Procurement Plan
CAISO	California Independent System Operator
CAM	Cost Allocation Mechanism
CARB	California Air Resources Board
CBA	California Balancing Authority (SDG&E); California Balancing Authority Area (SCE)
CCA	Community Choice Aggregation
CEC	California Energy Commission
CEDU	California Energy Demand Updated

COD	Commercial Operation Date
CP	Compliance Period
CPCN	Certificate of Public Convenience and Necessity
CPI	Consumer Price Index
CPM	Capacity Procurement Mechanism
CPUC	California Public Utilities Commission
CR	Community Renewables
CRE	Customer Renewable Energy
D.	Decision
DA	Direct Access
DBE	Diverse Business Enterprise
DER	Distributed Energy Resource
DG	Distributed Generation
DGD	Distributed Generation Deliverability
DLAP	Default Load Aggregation Point
DRA	Division of Ratepayer Advocates
ECR	Enhanced Community Renewables
ED	Energy Division
EE	Energy Efficiency
EJ	Environmental Justice
ELCC	Effective Load Carrying Capacity
EO	Energy Only
EPC	Engineering, Procurement, and Construction
ERR	Eligible Renewable Resource
ERRA	Energy Resource Recovery Account
ESP	Electric Service Provider

FCDS	Full Capacity Deliverability Status
FERC	Federal Energy Regulatory Commission
FFO	Funds From Operations
FIT	Feed-In Tariff
GCOD	Guaranteed Commercial Operation Date
GHG	Greenhouse Gas
GIDAP	Generator Interconnection and Deliverability Allocation Procedures
GO	General Order
GRC	General Rate Case
GT	Green Tariff
GTSR	Green Tariff Shared Renewables Program
GWh	Gigawatt-hours
HHZ	High Hazard Zone
HVDC	High Voltage Direct Current
ICE	Intercontinental Exchange
ID&WA	Irrigation District and Water Agency
IE	Independent Evaluator
IID	Imperial Irrigation District
IOU	Investor-Owned Utility
IPP	Independent Power Producer
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
IV	Imperial Valley
JRP	Joint Reliability Plan

kWh	Kilowatt-hour
LCBF	Least-Cost Best-Fit
LCR	Local Capacity Requirement
LSE	Load-Serving Entity
LTPP	Long-Term Procurement Plan
MACRS	Modified Accelerated Cost Recovery System
MVI	Motor Vehicle Incident
MW	Megawatt
NBC	Non-Bypassable Charge
NERC	North American Electric Reliability Corporation
NMV	Net Market Value
NP15 Hub	North of Path 15 Hub
NPV	Net Present Value
NQC	Net Qualifying Capacity
NYMEX	New York Mercantile Exchange
OSHA	Occupational Safety and Health Administration
OTC	Once-Through Cooling
PAV	Portfolio Adjusted Value
PCC	Portfolio Content Categories
PCIA	Power Charge Indifference Adjustment
PD	Proposed Decision
PEL	Procurement Expenditure Limitation
PFM	Petition for Modification
PG&E	Pacific Gas and Electric Company

PPA	Power Purchase Agreement
PPP	Public Purpose Program
PPTA	Power Purchase and Tolling Agreement
PQR	Procurement Quantity Requirement
PRG	Procurement Review Group
PRP	Preferred Resources Pilot
PTC	Production Tax Credit
PTO	Participating Transmission Owner
PV	Photovoltaic
QCR	Quarterly Compliance Report
QF	Qualifying Facility
R.	Rulemaking
RA	Resource Adequacy
RAM	Renewable Auction Mechanism
REC	Renewable Energy Credit
ReMAT	Renewable Market Adjusting Tariff
RETI	Renewable Energy Transmission Initiative
RFO	Request for Offers
RFP	Request for Proposal
RNS	Renewable Net Short
RNS Ruling	*Administrative Law Judge's Ruling on Renewable Net Short* issued May 21, 2014
RPS	Renewables Portfolio Standard
RPS Guidebook	CEC's RPS Renewables Portfolio Standard Eligibility Commission Guidebook
RTM	Real-Time Markets

Ruling	*Assigned Commissioner and Assigned Administrative Law Judge's Ruling Identifying Issues and Schedule of Review for 2017 Renewables Portfolio Standard Procurement Plans* issued May 26, 2017
SANS	Stochastically-Adjusted Net Short
SB	Senate Bill
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SONGS	San Onofre Nuclear Generating Station
SONS	Stochastically-Optimized Net Short
SPVP	Solar Photovoltaic Program
SRAC	Short Run Avoided Cost
SWPL	Southwest Powerlink
TOD	Time Of Delivery/Day
TPP	Transmission Planning Process
TRTP	Tehachapi Renewable Transmission Project
TURN	The Utility Reform Network
TWRA	Tehachapi Wind Resource Area
UOG	Utility-Owned Generation
VAR	Volt Ampere Reactive
VIE	Variable Interest Entities
VMOP	Voluntary Margin of Procurement (PG&E); Voluntary Margin of Over-Procurement (SDG&E and SCE)
WATER	Water Agency Tariff for Eligible Renewables
WECC	Western Electric Coordinating Council
WOD	West of Devers
WREGIS	Western Renewable Energy Generation Information System

(END OF ATTACHMENT A)