STATE OF CALIFORNIA Gavin Newsom, *Governor*

PUBLIC UTILITIES COMMISSION

505 VAN NESS AVENUE

SAN FRANCISCO, CA 94102-3298

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November 19, 2019

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Ratesetting

TO PARTIES OF RECORD IN RULEMAKING 18-07-003:

This is the proposed decision of Administrative Law Judge Sarah R. Thomas. 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 19, 2019 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.

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.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, *ex parte* communications are prohibited pursuant to Rule 8.2(c)(4)(B).

/s/ ANNE E. SIMON

Anne E. Simon
Chief Administrative Law Judge

AES:avs

Attachment

Decision **PROPOSED DECISION OF ALJ THOMAS (Mailed 11/19/2019)**

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 18-07-003

DECISION ON 2019 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS

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DECISION ON 2019 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS

Summary

California is a national leader in greening its electric grid. California's Renewables Portfolio Standard (RPS) has resulted in a large increase in the use of renewable energy by electric utilities and other entities serving electric customers in our State. Each year, these entities file their RPS Procurement Plans for Commission review and approval in accordance with Public Utilities Code Section 399.13(a)(1).[1]

Today's decision acts on the draft 2019 RPS Procurement Plans (with modifications adopted in this decision) of the following entities:

a. The large Investor-Owned Utilities the Commission regulates: Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E);

b. The Small and Multijurisdictional Utilities (SMJU) under our jurisdiction: Liberty Utilities (CalPeco Electric), LLC (Liberty); and Bear Valley Electric Company (BVES or Bear Valley). PacifiCorp, d/b/a Pacific Power (PacifiCorp) is required to file an Integrated Resource Plan as well as a "supplement" that provides additional information relevant to the RPS program. PacifiCorp filed the Integrated Resource Plan and the supplement too late for party comment. This decision therefore does not act on PacifiCorp's Plan, but discusses next steps;

c. Community Choice Aggregators (CCA): Apple Valley Choice Energy; City of Baldwin Park; City of Commerce;

[1] Public Utilities Code Section 399.13(a)(1) requires 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.

City of Hanford; City of Palmdale; City of Pomona; Clean Power Alliance; CleanPowerSF; Desert Community Energy; East Bay Clean Energy; King City Community Power; Lancaster Choice Energy; Marin Clean Energy; Monterey Bay Community Power; Peninsula Clean Energy; Pico Rivera Innovative Municipal Energy; Pioneer Community Energy; Rancho Mirage Energy Authority; Redwood Coast Energy Authority; San Jacinto Power; San Jose Clean Energy; Silicon Valley Clean Energy; Solana Energy Alliance; Sonoma Clean Power; Valley Clean Energy Alliance (City of Davis); and Western Community Energy of Seven Cities.

d. Energy Service Providers (ESP): 3 Phases Renewables; Agera Energy, LLC; American PowerNet Management, LP; Calpine Energy Solutions; Calpine PowerAmerica-CA, LLC; Commercial Energy of California; Constellation New Energy, Inc; Direct Energy Business; EDF Industrial Power Services (CA), LLC; Gexa Energy California, LLC; Just Energy Solutions; Liberty Power Delaware LLC; Liberty Power Holdings, LLC; Mansfield Power and Gas, LLC; Palmco Power CA; Pilot Power Group, Inc.; Praxair Plainfield, Inc.; Shell Energy; Tenaska California Energy Marketing, LLC; Tenaska Power Services Co.; The Regents of the University of California; Tiger Natural Gas, Inc.; and EnerCal USA, LLC (dba YEP ENERGY).

In some cases, the 2019 RPS Procurement Plans are sufficient and simply must be filed in final form no later than 30 days following Commission issuance of this decision. Other Plans lack required information and must be amended in the affected entities' final Plans.

Some highlights of this decision are as follows:

Large Investor Owned Utilities:

- We grant the requests of PG&E, SCE and SDG&E to forego holding a 2019 RPS solicitation because they already have sufficient renewable energy generation in their portfolios to meet the requirements of the RPS statute for this year.
- This decision also allows PG&E, SCE and SDG&E to sell RPS volumes under certain circumstances related to the timing and type of sale.

This decision also accepts the draft 2019 RPS Procurement Plans filed by other retail sellers of electricity that are subject to California's RPS program, but in some cases requires modification. Specifically, we require the following:

Small and Multijurisdictional Utilities:

The SMJUs, with the exception of PacifiCorp, filed compliant Plans. PacifiCorp is required to file two documents – an Integrated Resource Plan and a "supplement." PacifiCorp's filings occurred too late for party comment.

Community Choice Aggregators:

While the CCAs filed 2019 RPS Procurement Plans, many lacked details required by statute and Commission decision. The affected CCAs shall provide the missing detail with their final Plans due no later than 30 days following Commission issuance of this decision.

Energy Service Providers:

The ESPs also filed 2019 RPS Procurement Plans. Many ESP Plans lacked details required by statute and Commission decision, including required cost information. The affected ESPs shall provide the missing detail with their final Plans due no later than 30 days following Commission issuance of this decision.

This proceeding remains open.

1. Background

Rapid progress toward greening California's electricity sector has been achieved by legislative mandate, Commission action, and procurement by retail sellers of electricity. The California Renewables Portfolio Standard (RPS) program was established in 2002 by Senate Bill (SB) 1078 (Sher) with the initial requirement that 20 percent of electricity retail sales be served by renewable resources by 2017. The program was accelerated in 2006 under SB 107 (Simitian), which required that the 20 percent mandate be met by 2010. In April 2011, then-Governor Jerry Brown signed SB 2 (1X) (Simitian), which codified a 33 percent RPS requirement to be achieved by 2020. In 2015, Governor Brown signed SB 350 (de León) into law, which mandated a 50 percent RPS by December 31, 2030. SB 350 includes interim annual RPS targets with three-year compliance periods. In addition, SB 350 requires that 65 percent of RPS procurement must be derived from long-term contracts of 10 or more years beginning in 2021.

In 2018, Governor Brown signed SB 100 (de León) into law, which again increases the RPS to 60 percent by 2030 and requires all the state's electricity to come from carbon-free resources by 2045. SB 100 also advances the RPS program compliance requirements so that RPS-eligible resources are 44 percent of retail sales by December 31, 2024, 52 percent by December 31, 2027, and 60 percent by December 31, 2030.[2]

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[2] Additional details on the energy sector's progress toward meeting California's RPS procurement goals appear in the Commission's 2018 Annual Report, available at https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Renewables%20Portfolio%20Standard%20Annual%20Report%202018.pdf.

Footnote continued on next page.

In many prior decisions, the Commission has set forth the process for filing and evaluation of the RPS Procurement Plans (Plans) of electric corporations and other retail sellers. The statutory definition of "retail seller" includes small and large electrical corporations, Community Choice Aggregators (CCAs) and Energy Service Providers (ESPs).[3]

On April 16, 2019, the assigned Commissioner and assigned Administrative Law Judge (ALJ) issued a ruling (with dates modified by a May 7, 2019 ruling) setting the filing requirements and schedule for the 2019 RPS process (*2019 ACR*). Retail sellers filed their proposed annual RPS Procurement Plans on or before June 21, 2019. Comments on the RPS Procurement Plans were due on July 19, 2019, with reply comments on August 2, 2019.

All retail sellers that were required to file RPS Procurement Plans did so in a timely manner.[4] Comments on the Plans were filed by the California Wind Energy Association (CalWEA); Shell Energy North America, L.P. (Shell Energy); Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) (Joint IOUs); Independent Energy Producers Association (IEPA); American Wind Energy Association of California (AWEA-California); Bear Valley Electric Service (BVES), Liberty Utilities (Liberty), and PacifiCorp d.b.a. Pacific Power (PacifiCorp); Small Business Utility Advocates (SBUA); Public Advocates Office (Cal Advocates); and California Choice Energy Authority (CalChoice). Reply comments were filed by the Joint IOUs; SDG&E; PG&E; SCE; Alliance for Retail Energy Markets

[3] Pub. Util. Code §§ 399.12(f) & 218.

[4] PacifiCorp was allowed to file its Procurement Plan later than other entities, as we discuss in a later section. This decision does not act on PacifiCorp's Plan, which will instead be the subject of a subsequent decision.

(AReM); Cal Advocates; SBUA; Apple Valley Choice Energy, Marin Clean Energy, Monterey Bay Community Power Authority, Peninsula Clean Energy Authority, Pioneer Community Energy, Silicon Valley Clean Energy Authority, and Sonoma Clean Power Authority (Joint CCA Parties); and AWEA-California.

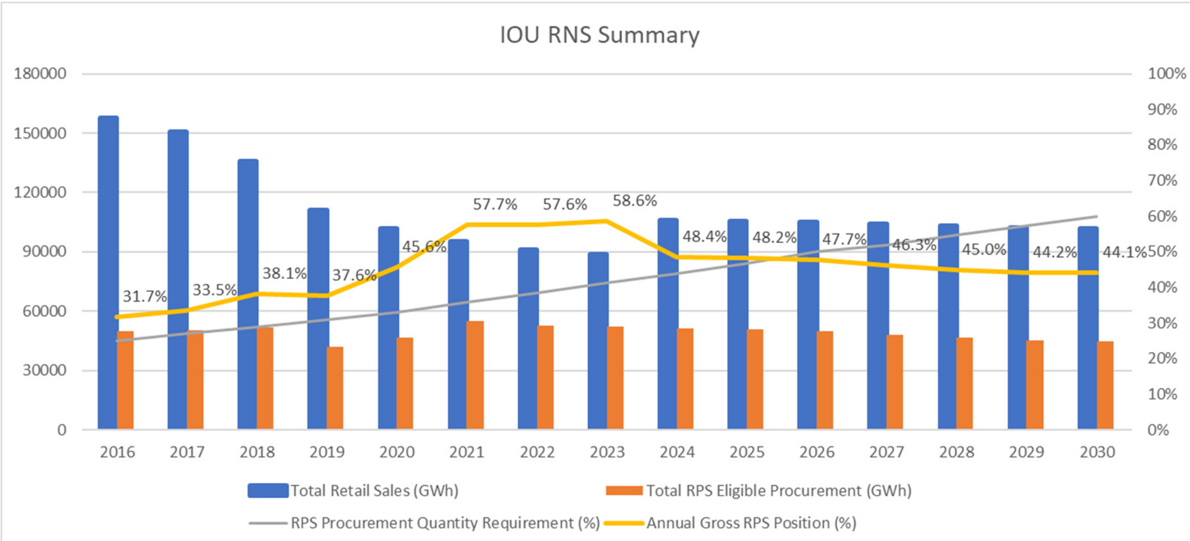
2. Status of RPS Procurement by Retail Sellers

The three large Investor-Owned Utilities (IOUs) report RPS progress in excess of program procurement requirements, which include a target of 29 percent RPS by 2018. For 2018, the IOUs delivered the following percentages of energy from RPS-eligible resources: PG&E 38.8%, SCE 36.5% and SDG&E 43%. None of the three large IOUs conducted a 2018 annual RPS procurement solicitation.

Figure 1 provides a summary of the large IOUs' actual and forecasted progress toward meeting the 60 percent RPS mandate. Based on the IOUs' Renewable Net Short (RNS) reporting, they are expected to collectively have need for additional procurement starting in 2026; however, that shortfall extends by several years through the forecasted use of excess Renewable Energy Credits (RECs) that have or will be "banked" as excess procurement.[5] Moreover, the IOUs' share of retail sales is expected to decrease from approximately 160,000 gigawatt hours (GWhs) in 2016 to 90,000 GWhs in 2023, largely as a result of the proliferation of CCAs. This change explains how the IOUs' RPS position is increasing even though their level of procurement remains relatively stable.

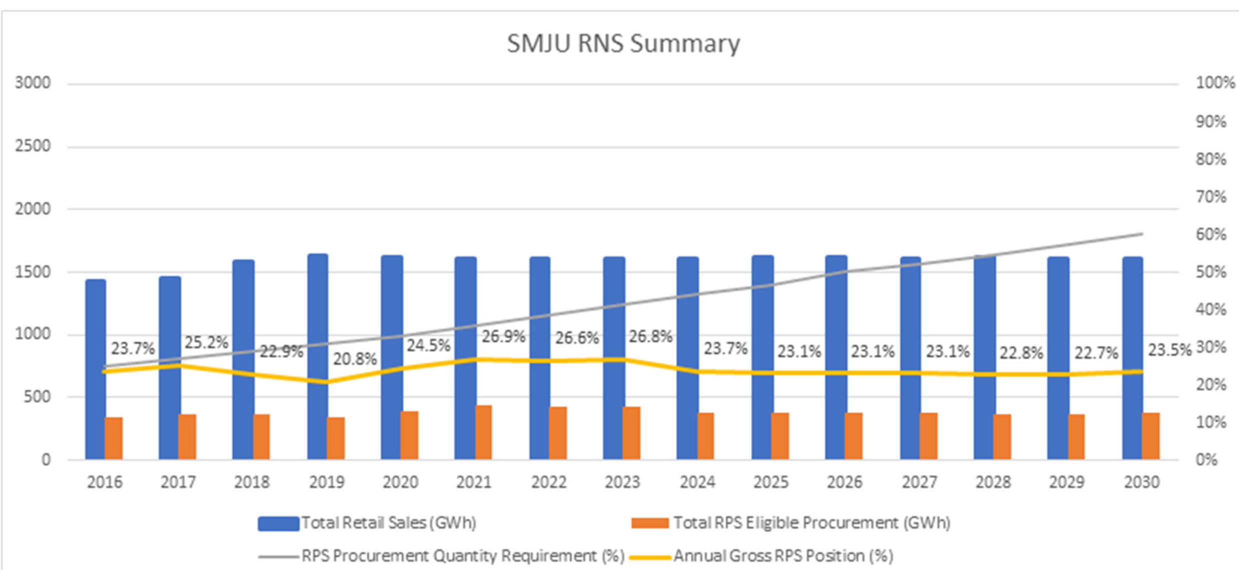
[5] *See* Decision (D.) 17-06-026 Section 3.1.5 for a detailed discussion on excess procurement of RECs which can be applied in later compliance periods. The RECs carried forward are colloquially referred to as the "Bank."

Figure 1: Aggregated IOU Progress Towards 60% RPS



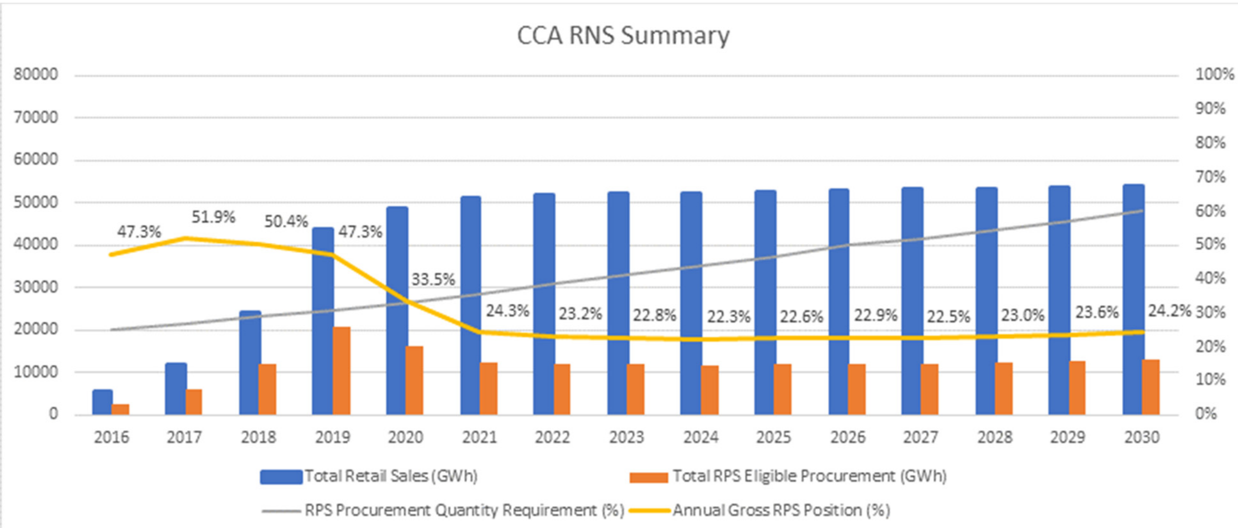
SMJUs collectively have a need for additional procurement (*See* Figure 2). SMJUs make up a small share of California's energy market, 1,500 GWhs, compared to California's other Load Serving Entity (LSE) groups.

Figure 2: Aggregated SMJU Progress Towards 60% RPS



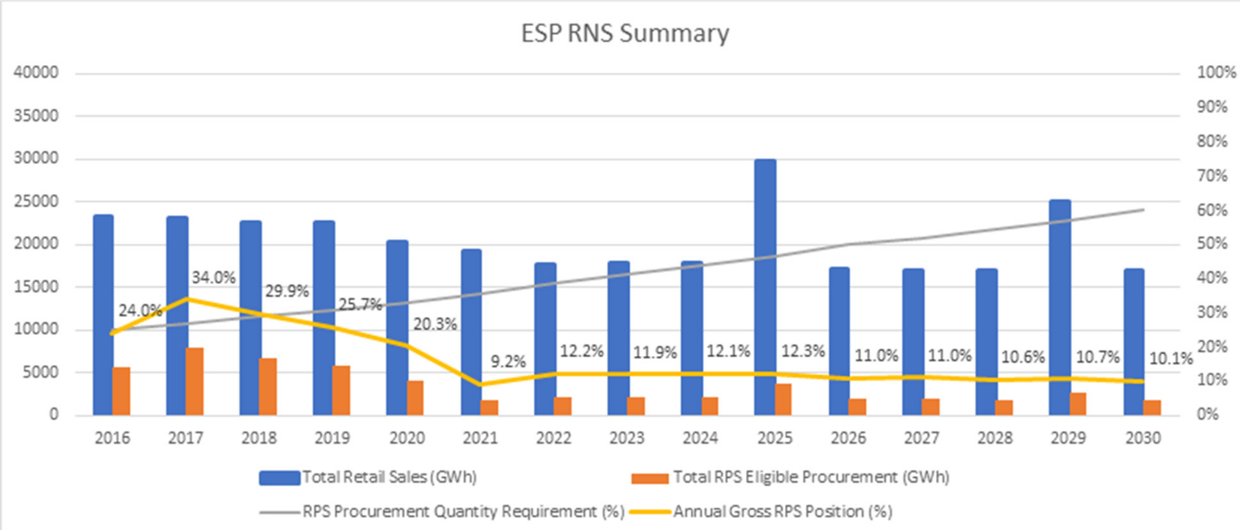
CCAs have historically had a "long" RPS position (*See* Figure 3), meaning that they have adequate supply. Based on the CCAs' RNS reporting, however, they are expected to collectively have a need for additional RPS procurement beginning in 2021. Over time the CCAs' share of retail sales has grown from less than 10,000 GWhs in 2016 to a forecasted 52,000 GWhs in 2023.

Figure 3: Aggregated CCAs Progress Towards 60% RPS



ESPs are expected to have a need for additional procurement starting in 2019 (*See* Figure 4). Historically, the ESPs have relied on short-term contracts in order to match their RPS obligation to their prevailing retail sales, which explains the lack of expected procurement beginning in the very near term.

Figure 4: Aggregated ESP Progress Towards 60% RPS



3. Organization of this Decision

The RPS statute requires that retail sellers prepare an annual RPS procurement plan for Commission review.[6] The Commission has reviewed and approved or accepted annual RPS procurement plans for over 10 years. As the RPS program has matured, review of the three large IOUs' procurement plans has become more routine. This year, 2019, marks the fifth year in a row that PG&E and SDG&E will forgo an annual RPS solicitation; it is the fourth year in a row for SCE.

Therefore, this year's decision accepting the RPS procurement plans is shorter than in past years. It describes only the sections of the IOUs', ESPs' and CCAs' procurement plans that are key, disputed, or changed from prior years. Where groups of filers (*e.g.*, CCAs) have submitted the same information, this decision discusses them in groups.

[6] Pub. Util. Code § 399.13(a).

This decision first sets out the requirements for each type of LSE required to file a 2019 RPS Procurement Plans. These requirements appear in more detail in the *2019 ACR*. Then, the decision addresses whether the Plans filed by PG&E, SCE and SDG&E meet the *2019 ACR* requirements, with an emphasis on new issues and a determination of changes we require to the final Plans due no later than 30 days following Commission issuance of this decision. The decision then describes the Plans of the SMJUs, the CCAs and the ESPs, and indicates required modifications. The decision then addresses party comments on all aspects of the 2019 RPS Procurement Plans, including issues described in connection with the description of specific Plans noted above. Finally, the decision summarizes whether the Plans are approved and indicates required modifications for the final Plans.

The final 2019 RPS Procurement Plans, due no later than 30 days following the effective date of this decision, shall each comply with these revisions, and approval of those final Plans is conditioned on such compliance. If a final Plan does not comply, LSEs are at risk of enforcement action by the Commission.

4. General Requirements for 2019 Procurement Plans – 2019 ACR

The *2019 ACR*, which this decision ratifies, provides that consistent with statutory requirements and the Commission's decisions, the IOUs, CCAs, and ESPs must comply with all of the requirements set forth below; SMJUs are subject to a subset of the requirements, as noted below. We do not repeat the requirements in full here; readers should refer to the *2019 ACR* for details on what is required for each item. Where an LSE has failed to list an item from Table 1 below, we discuss the requirement in more detail.

Table 1
Summary of Requirements for 2019 RPS Procurement Plans

Requirement	Large IOUs	Utilities subject to §§ 399.17 & 399.18 (SMJUs)	ESPs and CCAs
1. Assessment of RPS Portfolio Supplies and Demand	X	X	X
2. Project Development Status Update	X	X	X
3. Potential Compliance Delays	X	X	X
4. Risk Assessment	X	X	X
5. Quantitative Information	X	X	X
6. "Minimum Margin" of Procurement	X	X	X
7. Bid Solicitation Protocol, Including Least Cost Best Fit Methodologies	X	X	X
8. Consideration of Price Adjustment Mechanisms	X	X	X
9. Curtailment frequency, costs, and forecasting	X		X
10. Cost Quantification	X	X	X
11. Important Changes to Plans Noted	X	X	X
12. Redlined Copy of Plans Required	X	X	X
13. Safety Considerations	X	X	X

5. Requirements for Multijurisdictional Utilities Subject to Public Utilities Code Section 399.17

The RPS procurement requirements for multijurisdictional utilities are somewhat different from those for the large IOUs. The RPS statute allows these utilities to meet their RPS procurement obligations without regard to the Portfolio Content Category (PCC) limitations in Public Utilities Code Section 399.16.[7] The PCC limitations are designed to ensure that most renewable

[7] Pub. Util. Code § 399.17(b). The PCC limitations in Section 399.16 are explained in D.11-12-052, §§ 3.5-3.7.

energy procurement takes the form of high value new in-state generation, rather than instruments such as RECs.

However, PacifiCorp, as a multijurisdictional utility, is allowed 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 Public Utilities Code Section 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 served its IRP on the service list for this proceeding on October 13, 2019, too late for parties to comment. Further, D.08-05-029, Section 3.4.1, requires PacifiCorp to file a "supplement" to its IRP, to cover those elements required for RPS purposes but not part of the IRP. PacifiCorp filed the supplement on November 8, 2019, days before mailing of this decision, and too late for parties to comment. Thus, this decision does not evaluate PacifiCorp's filings.

6. Requirements for Small Utilities Subject to Section 399.18

The RPS statute also has different requirements for small utilities than for the large IOUs. Public Utilities Code Section 399.18(b) allows small utilities such as BVES and Liberty to meet the RPS procurement obligations without regard to the PCC limitations in Public Utilities Code Section 399.16. Further, while a small utility must file a procurement plan pursuant to Public Utilities Code

Section 399.13(a)(5), it may be tailored to the limited customer base and the limited resources of a small utility.

Accordingly, this Commission has required BVES and Liberty to prepare an RPS Procurement Plan with certain exclusions pertaining to curtailment frequency, costs, and forecasting.

7. Requirements for Electric Service Providers and Community Choice Aggregators

ESPs and CCAs must file RPS Procurement Plans consistent with the requirements of Public Utilities Code Section 399.13(a)(5). Therefore, each ESP and CCA must file a proposed RPS Procurement Plan that complies with the requirements of sections 1-13 in Table 1 above.

8. PG&E RPS Procurement Plan

8.1. Overview

Generally speaking, PG&E's Plan contains each of the elements required in Table 1 above, as noted below. This section primarily addresses key issues in PG&E's Plan and changes in PG&E's approach from prior years. This decision discusses the following issues from the *2019 ACR*; with regard to the other requirements, PG&E's draft Plan contains the required elements and no party raised an objection to these aspects of PG&E's Plan. The most significant changes in PG&E's Plan according to the utility relate to its 1) renewables sales (with many of the details claimed to be confidential), and 2) provision of "Time of Delivery" (TOD) information to renewable developers.[8]

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[8] An IOU provides TOD information in its RPS procurement contracts to communicate to renewables developers when energy deliveries might be more valuable to the system and allow them to respond with optimized project designs and bids. D.19-02-007, OP 16. In that decision, because PG&E had stopped providing this information based on the assertion that it was unlikely to reflect system need over the life of a Power Purchase Agreement, the Commission ordered PG&E and other large IOUs to provide TOD information, and allowed them two

Footnote continued on next page.

Table 2
PG&E RPS Procurement Plan 2019

1. Assessment of RPS Portfolio Supplies and Demand	X
2. Project Development Status Update	X
3. Potential Compliance Delays	X
4. Risk Assessment	X
5. Quantitative Information	X
6. "Minimum Margin" of Procurement	X
7. Bid Solicitation Protocol, Including Least Cost Best Fit Methodologies	X
8. Consideration of Price Adjustment Mechanisms	X
9. Curtailment Frequency, Costs, and Forecasting	X
10. Cost Quantification	X
11. Important Changes to Plans Noted	X
12. Redlined Copy of Plans Required	X
13. Safety Considerations	X

PG&E forecasts its cumulative Bank to exceed the calculated minimum Bank size over the next 10 years, in part due to dramatic recent and ongoing changes to PG&E's retail sales forecast. Accordingly, PG&E continues to seek authority in this 2019 RPS Plan to sell RPS volumes from its portfolio through short-term sales. The change in the volume of sales for 2019 and 2020 over the volume in 2018 is marked confidential.

PG&E states that it has no current need for additional RPS resources, and it proposes not to hold a voluntary solicitation to buy RPS products during the period covered by its 2019 RPS Procurement Plan. PG&E states it does not have an incremental need for RPS resources until at least 2029. PG&E projects that it

options, with one being that they furnish informational-only numbers. The IOUs chose this option, and this decision approves their filing.

will have incremental RPS procurement need after 2033, after applying volumes of RPS procurement above the requirement from past years in its Bank toward its current-year RPS needs beginning in 2029.

PG&E states that its RPS need is subject to uncertainty for several reasons:

- The Commission's review of portfolio optimization in the Power Charge Indifference Adjustment (PCIA) reform proceeding may result in changes to PG&E's Renewable Net Short (RNS) position if the Commission orders sales or allocation of PG&E's existing RPS portfolio.[9]
- In order to emerge from bankruptcy, the Bankruptcy Court and Commission must make approvals regarding a plan of reorganization for PG&E pursuant to Chapter 11 of the United States Bankruptcy Code and AB 1054 (2019). For purposes of this 2019 RPS Plan, PG&E assumed that its existing RPS contracts will continue in effect until expiration. On September 9, 2019 PG&E filed its proposed plan of reorganization, with amendments filed on September 23, 2019. While the PG&E Plan may be amended due to further developments, it provides that PG&E will assume all power purchase agreements including its RPS contracts.
- Expected increases in customers switching to service from CCAs and generating their own electricity have resulted in dramatic decreases in the IOUs' bundled retail sales projections. As retail sales decrease, the quantity of RPS energy required for PG&E to meet its RPS obligation falls, resulting in a decreased need for new RPS resources.

In response to load departure and PG&E's resulting long RPS position, PG&E plans to pursue two or three sales solicitations in which PG&E sells

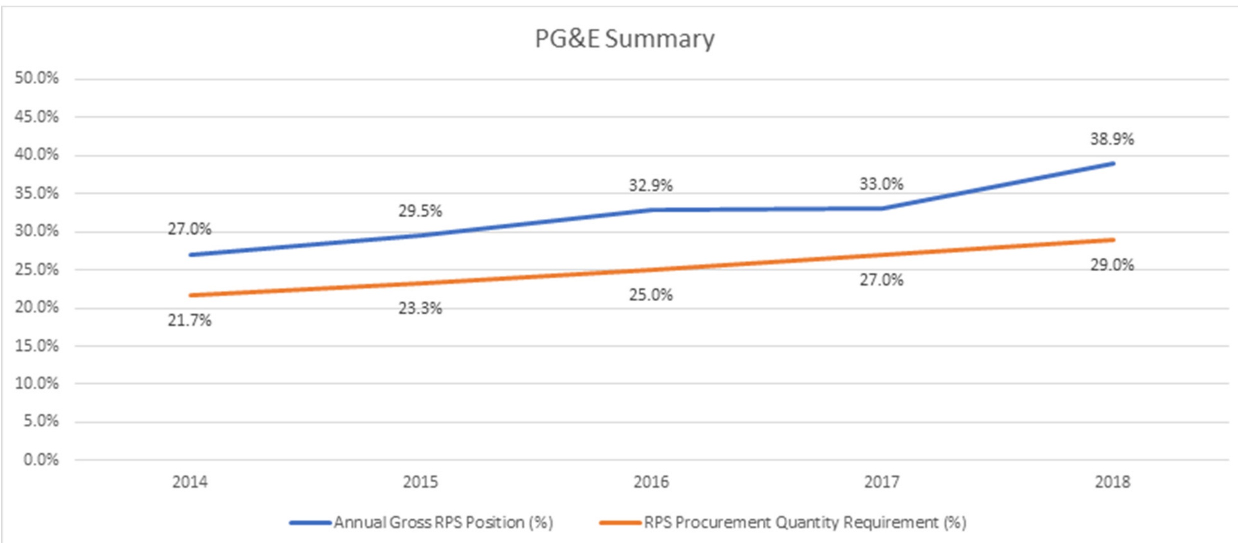
[9] PG&E notes that it is open to legislative proposals to establish a central buyer to ensure that all entities meet their RPS obligations and to procure resources of statewide benefit.

energy and RECs in short-term contracts of two years or less during the 2019 RPS Plan cycle for deliveries in 2020 and 2021.

8.2. Assessment of RPS Portfolio Supplies and Demand

PG&E states that it delivered 38.9 percent of its power from RPS-eligible renewable sources in 2018, up from 33 percent in 2017, as shown in Figure 5.

Figure 5



As noted above, PG&E will not need to procure additional RPS resources until 2029 and can use its Bank into 2033. PG&E has 7,000 Megawatts (MW) online or under development (with less than 100 MW falling in the "under development" category). This portfolio includes (a) utility owned solar and small hydro generation; (b) long-term RPS contracts for large wind, geothermal, solar, and biomass generation; and (c) small Feed-In Tariff (FIT) contracts for solar photovoltaic (PV), biogas, and biomass generation.

PG&E's key concern in its 2019 RPS Plan is the potential for excess resources in its portfolio and Bank. Therefore, PG&E plans to target 2 or 3 solicitations for the sale of bankable, bundled renewable generation and RECs in 2020. PG&E anticipates selling short-term products, specifically contracts of two years or less in duration. In confidential Appendix E of its Plan, PG&E lays out the details of its proposed solicitation and a *pro forma* sales agreement. PG&E states these details are largely unchanged from what the Commission approved in the 2018 RPS Plan.

PG&E asks to file short-term sales agreements resulting from a solicitation that are negotiated based upon the *pro forma* sales agreement, with any necessary modifications, as Tier 1 Advice Letters for Commission approval. PG&E reasons that because minimal negotiations will be needed, its proposal is consistent with the streamlined Tier 1 Advice Letter process authorized in D.14-11-042 for short-term sales agreements.

In that decision, the Commission determined that a Tier 1 Advice Letter process could be used as long as a utility has included a *pro forma* short-term contract as part of its approved RPS plan filing and the contract term is under five years. PG&E contends streamlined processes for both solicitation administration and Commission approval are required in order to allow for transactions to occur in 2020.

While tax credits have helped the development of the market for renewables, PG&E states that it expects renewables to continue to be cost-competitive in the future, whether or not the credits are extended. It states that siting and permitting of projects has supported PG&E's sustained high success rate. The company believes the renewable development market has stabilized for the near-term. For some technologies, such as PV, prices have dropped significantly due to various factors including technological breakthroughs, government incentives, and improving economies of scale as more projects come online.

Another trend, driven by the growth of renewable resources in the California Independent System Operator (CAISO or ISO) system, is the downward movement of mid-day wholesale energy market prices. PG&E projects that negative pricing is likely to increase in the future.

PG&E's Green Tariff Shared Renewables (GTSR) program, implemented pursuant to SB 43,[10] has been undersubscribed, resulting in the transfer of renewables procured for that program to the PG&E's RPS portfolio in 2018. PG&E anticipates the same pattern for 2019.

PG&E continues to procure RPS resources through the mandatory BioMAT program[11] even though it contends it has no need for the resources.[12] PG&E expresses concern that mandatory procurement such as the Bioenergy Market Adjusting Tariff (BioMAT), Renewable Market Adjusting Tariff (ReMAT), Biofuel Renewable Auction Mechanism (BioRAM) and Photovoltaic Renewable Auction Mechanism (PV-RAM), which apply only to the IOUs, puts IOUs at a disadvantage vis-à-vis ESPs and CCAs who lack these procurement mandates.

PG&E projects a decrease in retail sales in 2020 and a continued but modest decline through 2026 before growing slowly thereafter. These changes are driven by the increasing impacts of energy efficiency (EE), customer-sited

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[10] SB 43 (Stats. 2013, Ch. 413 (Wolk)). *See* D.15-01-051 and D.18-06-027 (implementing and modifying GTSR program).

[11] SB 1122 (Stats. 2012, Ch. 612 (Rubio)). Requires electrical corporations to collectively procure at least 250 MW of generation from developers of bioenergy projects that commence operation on or after June 1, 2013.

[12] PG&E Draft RPS Procurement Plan at 24. "PG&E continues to seek to procure resources under BioMAT despite a demonstrated lack of need for additional RPS resources."

generation, and CCA participation levels, and are offset slightly by an improving economy and growing electrification of the transportation sector.

Because PG&E currently has no incremental procurement need until after 2033 under existing RPS requirements, PG&E proposes not to hold an RPS solicitation during this RPS Plan cycle. PG&E states it has sufficient time in the coming years to respond to changing market, load, or regulatory conditions and will reassess the need for any future Requests for Offers (RFO) in next year's Plan.

PG&E hopes to use its Bank to meet part of its RPS procurement starting in 2029 as a means of reducing risk and ratepayer cost. PG&E contends it would be imprudent to use its entire projected Bank for RPS compliance, rather than to cover unexpected demand and supply variability and project failure or delay exceeding forecasts from projects not yet under contract. PG&E asserts that using the Bank as its Voluntary Margin of Procurement (VMoP) will reduce non-compliance risk, while also helping to avoid long-term over-compliance above the existing RPS targets and thus reducing long-term costs of the RPS Program, which could result if PG&E held both a Bank and an additional VMoP.[13]

8.3. Proposed Time of Delivery Factors

In the past, PG&E based its TOD factors on internally forecasted hourly prices, load forecasts, and capacity values. Prior to issuance of D.19-07-002, PG&E determined that it is increasingly difficult to accurately forecast TOD preferences within even the next decade, let alone for the duration of a typical

[13] The RPS statute allows a VMoP, which represents extra procurement over the statutory percentage requirements to account for project failures or similar events. The margin ensures the LSE meets the RPS percentage requirement regardless of these events. Pub. Util. Code § 399.13(a)(4)(D).

RPS Power Purchase Agreement (PPA) (*e.g.*, 20 years), given California's quickly evolving energy mix, policies, and markets. Therefore, with its 2018 Plan, PG&E proposed to eliminate TOD factors for any new RPS procurement contract executed in existing mandatory procurement programs, such as BioMAT, BioRAM, ReMAT, and PV-RAM.[14]

As a result of concerns with the elimination of this forecast, in D.19-07-002, the Commission ordered the IOUs to provide informational-only TOD information. The IOUs submitted a compliance TOD proposal on May 29, 2019, which PG&E included in its draft 2019 RPS Plan. We discuss the proposal in Section 14.2, which discusses party comments on all aspects of the 2019 RPS Procurement Plans.

8.4. CAISO Curtailment Due to Overgeneration

The *2019 ACR* asked 5 questions related to curtailment, over-generation, and negative pricing of renewables in the CAISO markets. PG&E's responses follow each question:

(1) Factors having the most impact on the projected increases in incidences of overgeneration and negative market price hours.

PG&E states that it agrees with the following statement of the CAISO itself:

> A swift rise in California's renewable energy capacity, especially solar generation, is the main driver behind the growing occurrence of oversupply. . . . Currently, the ISO's most effective tool for managing oversupply is to "curtail"

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[14] PG&E claims these programs benefit all customers and therefore all customers should pay their equitable share of program costs. Therefore, PG&E states that wherever consistent with law, PG&E will continue to oppose new RPS procurement mandates, to seek to suspend existing RPS procurement mandates, and to oppose any changes to existing RPS procurement mandates that would require PG&E to conduct additional RPS procurement. In general, PG&E believes that no RPS procurement should be mandated without a clear demonstration of need.

Footnote continued on next page.

> renewable resources. That means plant generation is scaled back when there is insufficient demand to consume production. . . . Curtailments can occur in three ways: economic curtailment, when the market finds a home for low-priced or negative-priced energy; self-scheduled cuts, which reduce generation from self-scheduled bids; and exceptional dispatch, when the ISO orders generators to turn down output.[15]

PG&E asserts that it relies on economic curtailment provisions to offer flexibility to the CAISO. In addition to overall generation, PG&E states, the location of generation is important. If a resource is built where it increases congestion, it can cause localized negative prices and curtailment even in addition to system conditions.

(2) Written description of quantitative analysis of forecast of the number of hours per year of negative market pricing for the next 10 years.

PG&E states that one approach is to use the statistical model that PG&E uses to develop forward prices. Using recent historical data, a regression is run to develop the relationship between fundamental market drivers and observed market Day-Ahead prices. The fundamental drivers include gas costs, Greenhouse Gas (GHG) compliance instrument costs, expected volume of must-take energy, and characteristics of flexible resources on the grid. Once that relationship is developed, PG&E forecasts the fundamental drivers forward, and applies the derived relationships to those forecasts to estimate prices. As more renewables are forecast to be added to the grid in coming years, PG&E expects more forward prices to be negative.

[15] CAISO, "Impacts of Renewable Energy on Grid Operations," May 2017, at 1 (available at http://www.caiso.com/Documents/CurtailmentFastFacts.pdf).

(3) Experience, to date, with managing exposure to negative market prices.

PG&E's response is that to the extent that it is contractually and operationally able to do so, PG&E has bid RPS-eligible resources in its portfolio into the CAISO markets. When there are negative prices in the CAISO market, these resources may be economically curtailed given their bid price. Economic-based curtailments awarded during negative price periods have created direct and indirect benefits for PG&E's customers and the CAISO. PG&E states that while direct benefits of economic bidding include avoided costs and CAISO market payments associated with negative prices, there can be other important benefits, including potentially avoiding the cost impacts across the rest of PG&E's portfolio due to extreme negative price periods, and also improving CAISO system reliability by helping to mitigate the occurrence, duration, or severity of negative price periods or overgeneration events. PG&E concludes that the overall trends in both the frequency and magnitude of negative prices in recent years suggests that the CAISO is able to generally balance supply and demand using economic curtailment rather than administratively curtailing generation.

(4) Direct costs incurred, to date, for incidences of overgeneration and associated negative market prices.

PG&E states that there were no incidences of overgeneration, as this term is defined by the CAISO, in 2018. PG&E asserts that the ability for the CAISO to control renewable output through economic curtailment is a key tool in preventing overgeneration.

(5) Overall strategy for managing the overall cost impact of increasing incidences of overgeneration and negative market prices.

Here, PG&E repeats what it said in 2018. Regarding 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 its forecast.

We note that SDG&E quantified the cost impact of overgeneration, as discussed in the section of this decision analyzing SDG&E's Plan. PG&E shall provide similar information with its 2020 Plan.

8.5. Cost of RPS Compliance

PG&E notes that since 2015 its RPS-eligible procurement and generation costs have stabilized around $2.4 billion per year. For 2019-2030, PG&E forecasts that its annual RPS portfolio costs will average $2.35 billion, with somewhat lower costs over the first part of forecast period due to greater anticipated RPS sales revenue.

PG&E's average RPS rates (in Appendix B of its Plan) rise steadily through the first half of the forecast period and then decline gradually through 2030. The underlying bundled load declines in the first part of the forecast due to continued anticipated CCA growth and then gradually increases due to anticipated increases in electric vehicle usage.

9. SCE RPS Procurement Plan

9.1. Overview

Generally speaking, SCE's Plan contains each of the elements required in Table 1 above. This section addresses key issues in its Plan, and changes in SCE's approach from prior years. SCE's 2019 draft RPS Procurement Plan submitted on June 21, 2019 states that SCE has no present need for additional renewable resources, and as a result does not propose to hold a 2019 RPS solicitation. SCE forecasts it can meet RPS requirements beyond 2030 using its Bank. It reports that it had 36.5 percent RPS in its portfolio in 2018. SCE anticipates an initial net short in 2028, but with use of the Bank it should be able to meet requirements in 2030 and beyond.

One key change SCE proposes relates to its sale of RECs. Revisions include requesting the ability to transact through additional mediums and pre-approval of REC sales. The additional transaction mediums include brokers, exchanges, and electronic solicitations. SCE proposes to conduct such REC sales in accordance with what it characterizes as strict upfront standards and criteria.

The criteria SCE proposes would allow pre-approval of bilateral REC sales, if entered into after and within 4 months of a solicitation and meeting certain term, pricing, volume and other criteria. (SCE requests confidential treatment of those specific criteria.) "Pre-approval" would mean SCE is not required to submit an Advice Letter (currently a Tier 1 or Tier 3 Advice Letter process is required depending on the contract) for approval of such transactions. SCE also requests pre-approval to enter into transactions with brokers and exchanges if they meet the term limits (3 years or less), pricing, volume and other criteria contained in confidential Appendix E to SCE's Plan.

SCE states it requests these changes because the marketplace for REC sales has changed significantly. Due to load migration to CCAs and Direct Access (DA) expansion, SCE is very long on RECs, and CCAs and other ESPs are actively seeking RECs. Thus, according to SCE, the ability to conduct sales through brokers and have preapproved sales will allow more flexibility to transact, allow SCE access to more markets, provide approval efficiency, and maximize customer value.

SCE has had authority to sell RECs in all three PCCs since last year's decision but has not sold PCC 3 RECs in the past year. It explains that the PCC 3

RECs seemingly have low value. Therefore, SCE proposes changes to the price floor for RECs (while keeping the details confidential) to increase the possibility of REC sales.

Also new in this year's Plan is SCE (and other IOUs') new informational-only TOD data, as discussed for the other large IOUs elsewhere in this decision. After issuance of D.19-02-007, the IOUs developed a joint proposal for informational-only TOD heat maps, which SCE included in its draft 2019 RPS Plan. In the past IOUs provided TOD information in RPS solicitation materials and procurement contracts to communicate to renewables developers when energy deliveries might be more valuable to the system and allow them to respond with optimized project designs and bids. Pursuant to D.19-02-007, Ordering Paragraph (OP) 17, adopting the 2018 RPS Plan, the IOUs developed a joint proposal for informational-only TOD heat maps and mailed it to the service list of this proceeding on May 30, 2019. SCE includes its informational-only TOD factors from the IOUs' joint proposal in Appendix K of its 2019 RPS Procurement Plan.

SCE also proposes changes to its *pro forma* renewable PPA and its Least Coast Best Fit (LCBF) methodology. SCE states its changed PPA is based on a contract approved in Resolution E-5004 for contracting with distributed energy resources. It is technology-neutral, which SCE states will allow for better comparison across SCE's different solicitations. The new *pro forma* contract includes wind, geothermal and other renewable resources. The only substantive change according to SCE relates to the TOD factors is noted in the previous paragraph.

The LCBF change SCE proposes would allow the utility, among other things, to give preference to renewables located in certain communities pursuant to Public Utilities Code Section 399.13(a)(7).[16] These changes are aimed at promoting workforce development and aiding disadvantaged communities.

Review of the draft Plan shows that SCE has submitted the following required information from the *2019 ACR*.

Table 3
SCE RPS Procurement Plan 2019

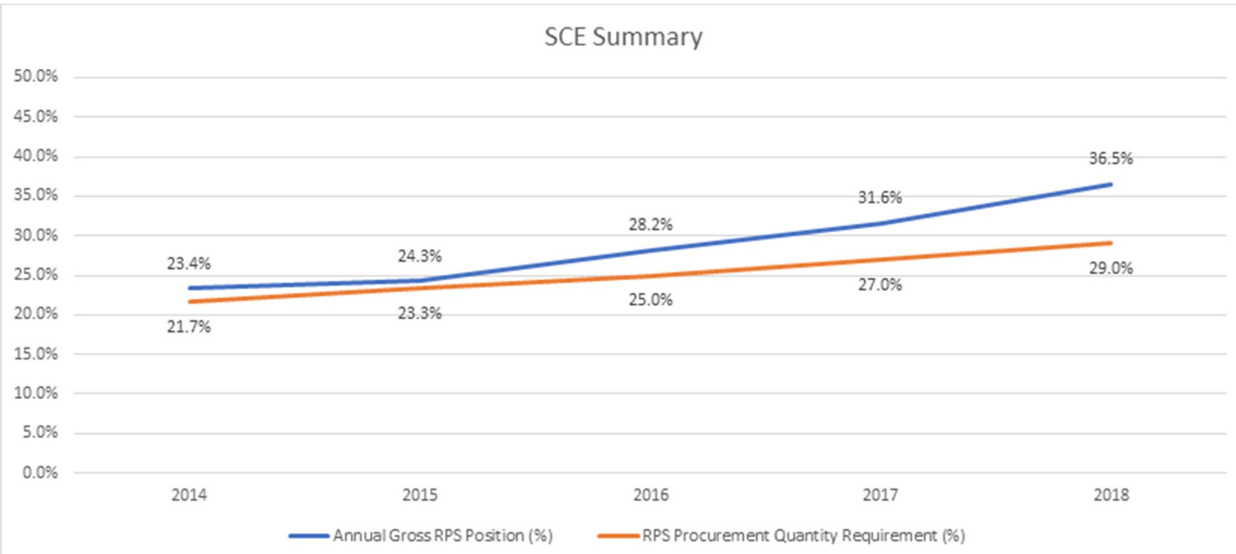
Required Elements for 2019 RPS Procurement Plans	Response included?
1. Assessment of RPS Portfolio Supplies and Demand	☒
2. Project Development Status Update	☒
3. Potential Compliance Delays	☒
4. Risk Assessment	☒
5. Quantitative Information	☒
6. "Minimum Margin" of Procurement	☒
7. Bid Solicitation Protocol, Including Least Cost Best Fit Methodologies	☒
8. Consideration of Price Adjustment Mechanisms	☒
9. Curtailment Frequency, Costs, and Forecasting	☒
10. Cost Quantification	☒
11. Important Changes to Plans Noted	☒
12. Redlined Copy of Plans Required	☒
13. Safety Considerations	☒

[16] The statute states: "In soliciting and procuring renewable energy resources for California-based projects, each electrical corporation shall give preference to renewable energy projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants, and greenhouse gases."

9.2. Assessment of RPS Portfolio Supplies and Demand

SCE asserts it is on target with RPS requirements and need not conduct a solicitation for additional renewables in 2019. As shown in Figure 6, SCE achieved 36.5 percent renewable energy in 2018, up from 31.6 percent in 2017.

Figure 6



SCE proposes to increase REC sales through brokers, exchanges and electronic solicitations, and asks that certain REC sale transactions receive advance approval (without an Advice Letter approval process) if they meet certain criteria. As noted below, we deny SCE's request for pre-approval of sales meeting its proposed criteria, its price floor, and its proposed sales volume in part. We also reject its request to use brokers and exchanges.

SCE did not hold an RPS solicitation in 2016, 2017 or 2018 but did sign one bilateral contract for 107 MW and four BioMAT contracts for 6 MW. SCE's RNS calculations appear in Appendix C and contain some confidential data. However, SCE is meeting its RPS percentage requirements and we agree that it need not conduct an RPS solicitation in 2019.

9.3. Departing Load

SCE points to several developments that will reduce the number of bundled customers the utility serves. Decision 19-05-043 resulted in 1,747 GWh new DA load state-wide over two years starting in 2020. SCE also expects additional cities and eligible public entities within its territory to begin CCA service. SCE incorporates existing departing CCA load in its Plan. It states that additional cities, counties, and governmental aggregations within the SCE service territory have either initiated contact, requested load data from SCE, or passed a municipal ordinance related to their interest and intention to developing CCAs. SCE states that these entities have the potential to represent a significant additional departure of load from SCE's bundled procurement service. As additional large departures come to fruition, they will have proportionally significant impacts on SCE's progress towards meeting its RPS compliance goals by reducing SCE's potential RPS need. Nonetheless, SCE asserts that departing load should not impact its planned procurement activities unless and until new CCAs formalize their departure through various procedural and substantive filings.

SCE asserts that future policy changes with regard to DA reopening could bring additional impact to SCE's planned procurement, but SCE has adjusted its procurement plan to accommodate known departing load.

9.4. Potential Compliance Delays

SCE identifies five factors that may challenge its achievement of the RPS goals, down from six in 2018. It no longer cites the increasing proportion of intermittent resources in its renewables portfolio as a challenge, but continues to list (1) curtailment; (2) permitting, siting, approval, and construction of both renewable generation projects and transmission; (3) a heavily subscribed interconnection queue; (4) developer performance issues; and (5) load uncertainty associated with possible departing load and increasing electrification of transportation.

The only factor that has changed since SCE's 2018 Plan relates to item 2 – new transmission projects. SCE explains that its Eldorado-Lugo and Lugo-Mohave Series Capacitor Project, a "Policy Driven Transmission Project" approved through the CAISO Transmission Planning Process, will be delayed. The project, which SCE asserts is required for 13 generation projects totaling about 2,500 MW, currently has a completion date of June 2021. The delay in the project's completion will delay several of the generation projects' ability to achieve Full Capacity Deliverability Status.

9.5. Curtailment Due to Overgeneration

SCE expects a small but increasing level of curtailment in solar between 2019 and 2020. SCE cites historical CAISO system-wide data showing that the CAISO curtailed about 1.5 percent of solar production and less than 0.2 percent of wind production in 2018. Solar curtailments peaked in March and October last year; this year they are showing a similar pattern with solar curtailments trending higher than last year. Solar curtailments were approximately 5.3 percent in March 2019, compared to 4.4 percent in March 2018, according to SCE.

Considering the increasing solar and wind penetration, and retirements of gas-fired resources, SCE expects that RPS curtailments will increase. However, SCE notes that forecasting such curtailments is challenging since many factors affect them – inherent solar and wind production variability, uncertainty in load forecasts, hydro conditions, and available imports. SCE notes that CAISO and stakeholders are working on several initiatives to improve system capabilities to manage oversupply – the Western Energy Imbalance Market expansion, improved regional coordination, Time of Use (TOU) rates, Demand Response programs, and Energy Storage.[17]

9.6. LCBF Criteria

To accommodate Public Utilities Code Section 399.13(a)(7)'s requirement on preference for locating renewables in disadvantaged communities, SCE has revised its LCBF criteria. The revision has impacts on workforce development and disadvantaged communities, as required by D.19-02-007.[18]

9.7. Authorization to Sell Renewable Energy Credits

A key change in SCE's procurement strategy relates to its REC sales. It seeks to increase the ways it sells RECs and seeks advance authority for certain types of sales. SCE's REC sale proposal contains two changes over 2018: 1) authorization to enter into a limited quantity of REC sales through a pre-approval process; and 2) use of brokerages and exchanges to sell RECs.

The pre-approved REC sales SCE proposes to include several confidential details, contained in Confidential Appendix E to SCE's Plan. SCE explains that its proposed change – which allows pre-approval of transactions that meet certain price floor, volume limit and term limit criteria – is necessary due to changes in the REC market. It explains that there are more CCAs in the market and an increase in the amount of load that can be served as DA. Therefore, there is a broader market for RECs. SCE states that it wants to be responsive to that broader market and allow for the quickest, most efficient approval process. SCE asserts that the upfront standards (term length, pricing and volume limits) ensure SCE will act prudently.

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[17] As is true for PG&E, SCE did not quantify the cost of overgeneration as SDG&E did. In its 2020 Plan, SCE shall include this information, along with SDG&E and PG&E.

[18] D.19-02-007, at 96-100 & OP 16.

SCE seeks pre-approval for each of its contracts resulting from a solicitation and utilizing the *pro forma* REC Sales Agreement attached to its RPS Plan as Appendix I, as well as bilateral contracts that use the *pro forma* REC Sales Agreement and that are executed after SCE receives bids for a sales solicitation resulting from its 2019 RPS Procurement Plan. Transactions for bilateral REC sales that do not use the *pro forma* agreement, have term lengths that extend beyond 2024, do not conform to the confidential price floor in Appendix E to SCE's Plan, or that are not executed after SCE receives bids for a sales solicitation resulting from its 2019 RPS Plan, would be subject to a Tier 3 Advice Letter approval process.

In its proposal for REC sales using brokers and exchanges, SCE states that to its knowledge no exchange currently carries RECs. SCE seeks authority from the Commission to act in case RECs are ultimately listed on an exchange, and SCE can receive competitive pricing selling through the exchange. SCE states that it has encountered opportunities to sell RECs at competitive prices through brokers. It asserts that using brokers would be in line with current practices of utilizing brokers for non-renewable resources, that brokers provide a forum for market participants to trade anonymously with one another, and that the price that brokers provide is known and available to any interested market participant and representative of the market at the time of the transaction. SCE proposes where possible, to obtain multiple broker quotes to ensure SCE receives a fair market price for the REC transaction.

10. SDG&E 2019 RPS Plan

10.1. Overview

Review of the draft Plan shows that SDG&E has submitted the following information as required by the *2019 ACR*.

Table 4
SDG&E RPS Procurement Plan 2019

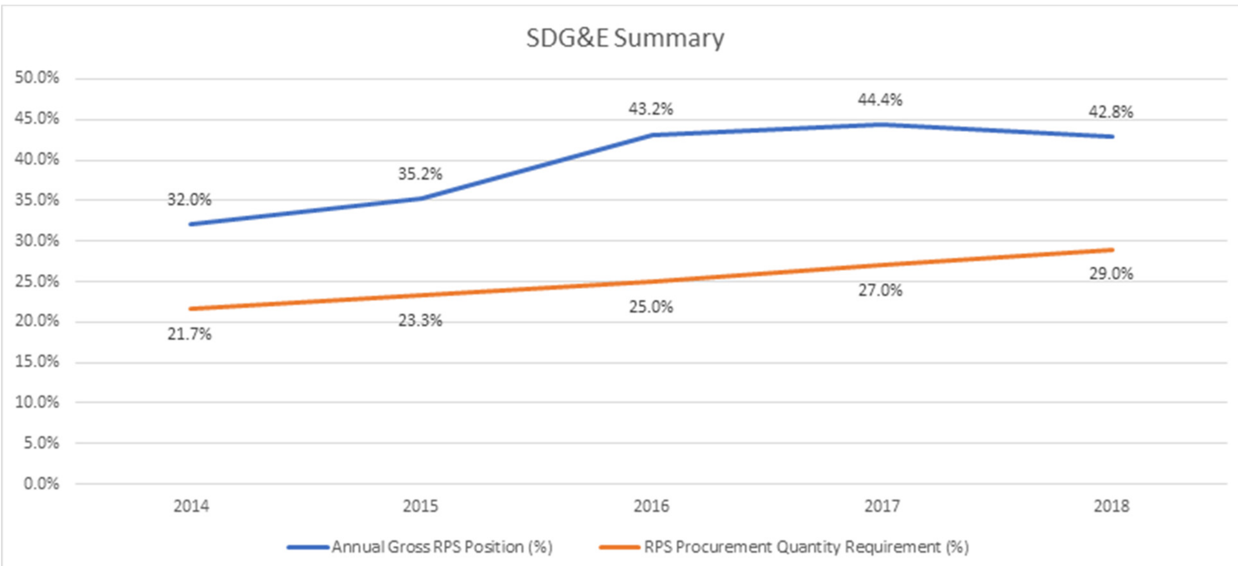
Required Elements for 2019 RPS Procurement Plans	**Response included?**
1. Assessment of RPS Portfolio Supplies and Demand	☒
2. Project Development Status Update	☒
3. Potential Compliance Delays	☒
4. Risk Assessment	☒
5. Quantitative Information	☒
6. "Minimum Margin" of Procurement	☒
7. Bid Solicitation Protocol, Including Least Cost Best Fit Methodologies	☒
8. Consideration of Price Adjustment Mechanisms	☒
9. Curtailment Frequency, Costs, and Forecasting	☒
10. Cost Quantification	☒
11. Important Changes to Plans Noted	☒
12. Redlined Copy of Plans Required	☒
13. Safety Considerations	☒

This section primarily addresses key issues in SDG&E's Plan that have changed from prior years. SDG&E's draft 2019 RPS Procurement Plan submitted on June 21, 2019 states that SDG&E has no present need for additional eligible renewable resources, and as a result does not propose to hold a 2019 RPS solicitation. It reports that it had renewable procurement equivalent to 43 percent of retail sales in 2018, 97 percent of which was from long-term contracts. Although SDG&E forecasts an initial net short in 2025, with the use of its banked procurement SDG&E anticipates being able to meet RPS requirements through 2033. SDG&E states that it intends to monitor the market to determine whether it is in the best interests of its customers to sell excess procurement.

10.2. Assessment of RPS Portfolio Supplies and Demand

SDG&E asserts it is on target with RPS requirements and does not need to conduct a solicitation for additional renewables in 2019. As shown in Figure 7, SDG&E achieved approximately 43 percent renewable energy in 2018, down slightly from 2017 due to contract expiration and REC sales.

Figure 7



SDG&E also highlights the impact of departing load on RPS compliance. Within SDG&E's service territory, Solana Beach was the first CCA to begin operations in June of 2018; however, various other cities are actively exploring the adoption of a CCA, including the City of San Diego, which represents around 40 percent of SDG&E's load. Further, on June 3, 2019, a Commission decision was issued in R.19-03-009, increasing the DA cap pursuant to SB 237 (2018, Hertzberg). Load departure reduces SDG&E's volume of retail sales, thereby increasing its annual RPS position. Finally, SDG&E notes that the Commission is currently considering further review of the PCIA in Phase 2 of R.17-06-026, the final outcome of which may impact SDG&E's RNS, as well as the volumes of RECs that SDG&E decides to sell.

SDG&E states that it continually seeks to manage its portfolio prudently while ensuring compliance with the State's clean energy goals, including the following regulatory factors:

a) RPS Program Rule & Related Factors: Includes renewable facilities eligibility and REC verification (overseen by the California Energy Commission (CEC)) and RPS compliance rules (overseen by this Commission). More recently, SB 350 enacted changes to the RPS banking rules, which are now applicable to SDG&E per its election to utilize them beginning in Compliance Period (CP) 3. SDG&E has updated its RNS table under Appendix 1 to comport with the new SB 350 banking rules, assuming for RNS calculation purposes that eligible excess procurement will be utilized in future compliance periods.

b) Policy Procurement and Related Factors: SDG&E states that California's commitment to renewable distributed generation continues to shape the State's renewable mix, and as LSEs reach compliance, they may be required to shift procurement from utility-scale project to small-scale distributed generation projects. References to SB 43 (GTSR), SB 1122 (BioMAT and ReMAT), and the Commission's implementation of the RAM and BioRAM, are listed as legislative and policy activities related to this goal, as well as more recent procurement decisions, including the adoption of D.18-12-002, which requires SDG&E to make available for sale all of the future RECs associated with SDG&E's BioRAM contract(s) as PCC 1 RECs, as well as Commission Resolution E-4977, implementing SB 901, which directs SDG&E to extend its BioRAM contracts for five years.

c) Other Procurement Authorizations and Related Factors: RPS-eligible procurement that occurs outside of the RPS program, including additional procurement authorizations that occur through the IRP process, meeting local capacity resource (LCR) needs, and through energy storage procured to meet the AB 2514 energy storage targets or

> additional energy storage programs and investments pursuant to AB 2868. While energy storage itself is not explicitly RPS-eligible, SDG&E states that it will count procured energy storage capacity towards its RPS targets in the future if the CEC determines them to be RPS-eligible.

A wide variety of procurement programs exists both within and in addition to the RPS program, which SDG&E asserts help support overall portfolio diversity. Another factor that will influence SDG&E's portfolio diversity, as well as help address integration and overgeneration, is the LCBF calculation that SDG&E will use to select shortlisted projects. The LCBF methodology included in Appendix 8 of SDG&E's 2019 RPS Plan now includes an interim integration adder, which SDG&E claims will ensure integration is factored into bid evaluation, with the objective of selecting a diverse portfolio in consideration of system needs and reliability. Finally, Section 12 of SDG&E's 2019 Plan outlines how SDG&E proposes to address the integration of renewables and the issue of overgeneration, both of which can contribute to the incidence of economic curtailment.

SDG&E states that its proposal not to procure for the 2019 RPS Plan cycle is consistent with SDG&E's 2018 IRP, which did not forecast a procurement need for RPS resources in the near term. Going forward, SDG&E states that it will incorporate any RPS procurement authorized by the IRP into its RPS Plan, as necessary.

10.3. Risk Assessment

SDG&E states that it assesses risk on an ongoing basis utilizing written assessments and periodic status update meetings with developers, especially as it relates to building new resources, delayed construction, and determining whether there is a risk that power will not be delivered. SDG&E has fewer projects in development than in prior years, while current project development has been more successful.

Developing projects represent only 3 percent of SDG&E's peak load, and SDG&E does not anticipate a large increase in the volume of future project build out. As such, SDG&E's risk assessment is mainly qualitative, including aspects such as local reliability, benefits to disadvantaged communities, resource diversity, environmental stewardship and workforce development. While, similar to prior reports, SDG&E identifies several "dynamic factors" outside of SDG&E's control that could impede progress towards achieving RPS goals, it does not anticipate any compliance delays at this time.

10.4. Bid Solicitation Protocol, Including LCBF

SDG&E states that it will enter an RPS Sales solicitation to the extent that selling RECs provides a greater benefit to SDG&E's customers than banking excess RPS procurement. SDG&E also states that it may explore the option of assigning one or more entire RPS contracts to a third-party, which may be done in addition to, or instead of, selling a portion of its RPS contracts.

SDG&E highlights that the contract reassignment process may present challenges, as SDG&E would need to secure approval from the renewable facility prior to the assignment of its contract to a third-party buyer. However, this option may also present advantages to a third-party buyer in terms of geographic location and portfolio fit. In cases where SDG&E determines that a contract assignment Request for Proposal (RFP) may be beneficial, SDG&E envisions conducting the Contract Assignment RFP in a similar manner, and potentially in parallel with, an RPS Sales RFP, including: 1) hiring an Independent Evaluator to oversee the process, 2) taking reasonable measures to ensure renewable facilities that may be assigned remain informed, 3) consulting with the Procurement Review Group (PRG) before and after offers are received, 4) marketing the RFP to a large group of potential Assignees, 5) publishing a clear and transparent set of RFO Protocols, and 6) performing an LCBF analysis to determine which bids, if any, would be beneficial to SDG&E's customers. Following the selection of any winning bids, SDG&E proposes to submit a Tier 2 Advice Letter for approval of any fully executed agreement, or a Tier 1 Advice Letter if no agreement results from the RFP.

10.5. Economic Curtailment Frequency Costs and Forecasting

In SDG&E's estimation, the issue of curtailment is a result of the operational characteristics of the facilities within the renewable market. These resources are as-available and intermittent (that is, they generate only when the wind is blowing or when sunlight strikes the panel), 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 during 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, resulting in integration issues, specifically overgeneration, which in turn leads to economic curtailment orders and negative pricing.

SDG&E forecasts market price profiles by calculating the net load for its service territory, using hourly customer load, solar and wind profiles that are forecasted to continue until each individual generation contract ends. SDG&E states that 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 significant cost savings for its customers.

SDG&E states it has managed its exposure to negative market prices by having the flexibility to reduce generation when needed. This flexibility is the result of negotiating the ability to economically curtail its contracts for renewable generation, including strengthening the language regarding economic curtailment in its *pro forma* PPA to be used in future contracting. SDG&E has renegotiated many of its contracts to minimize adverse impacts on customers and continues to negotiate the few remaining contracts that do not currently contain economic curtailment rights. SDG&E also mitigates the impact of negative prices to its ratepayers by economically bidding dispatchable resources into CAISO. To the extent SDG&E submits cost-based bids reflecting variable costs, it allows CAISO to reduce generation from SDG&E's resources when they are not needed or economic.

SGD&E states that it had a direct impact of approximately $20 Million from 2015-2018 from overgeneration and associated negative market prices.[19] SDG&E paid this amount to the CAISO for generating during times of negative prices, for all of SDG&E's resources. The majority of the costs occurred between 9:00 a.m. and 3:00 p.m. during the spring months.

10.6. Imperial Valley

SDG&E did not hold a 2018 RPS RFO; however, its RPS portfolio currently contains 12 contracts in the Imperial Valley/Imperial Irrigation District territory, that when completed will provide an estimated 3,100 GWh per year. As of April 2019, eleven of these projects have reached commercial operation, representing approximately 3,000 GWh per year. Additionally, projects located

[19] As noted above, the other two large IOUs did not quantify this information. In their 2020 Plans, they should include the same information as SDG&E.

Footnote continued on next page.

within the Imperial Valley, and either directly connected or dynamically transferred into SDG&E's service territory by the CAISO, are eligible to participate in SDG&E's Green Tariff Shared Renewables program.[20] Further, projects from the Imperial Valley were allowed to submit bids in SDG&E's Advice Letter 2717-E, concerning initial procurement from the Green Tariff component via RAM. SDG&E currently has one Green Tariff project in development in the Imperial Valley, with a total estimated generation of 116 GWh per year.

11. Small and Multijurisdictional Utilities (SMJU)

11.1. Overview

The small and multijurisdictional utilities are Bear Valley, PacifiCorp, and Liberty. Pursuant to the *2019 ACR*, these utilities were required to submit RPS procurement plans that provided the information required in Sections 5.1-5.8, and 5.10-5.13 of the *2019 ACR*. PacifiCorp, as a multijurisdictional utility, is permitted to use its 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 Public Utilities Code Section 399.17(d) and D.08-05-029.

Bear Valley and Liberty timely filed their Draft 2019 RPS Plans, including all elements required by the *2019 ACR*, and we approve these Plans with certain modifications. Key changes to the plans from prior years are briefly described below. PacifiCorp filed its IRP and RPS supplement too late for comment by parties. The Commission will consider its IRP and supplement and address the merits of the filings in a separate decision.

[20] D.15-01-051 at 35.

11.2. Bear Valley and Liberty 2019 Plans

On March 8, 2019, Bear Valley submitted Application (A.)19-03-008 for approval to acquire, own and operate a 7.9 MW solar photovoltaic generation facility located on Baldwin Lake land within Bear Valley's service territory. The project is expected to satisfy approximately 25-30 percent of Bear Valley's RPS requirements between 2020-2030 and is estimated to operate through 2050. Assuming Bear Valley is granted approval for this project, Bear Valley forecasts that it will meet nearly all of its RPS requirements through 2023 with existing contracts. However, due to the expiration of its contract with Avangrid in 2023, Bear Valley states that it will likely issue an RFP 18 to 24 months prior to the expiration of the current contract to satisfy Bear Valley's RPS requirements in 2024 and beyond. Finally, Bear Valley states that it has taken and may continue to take advantage of unbundled RECs to meet its RPS obligations.

Liberty currently serves its customers through a combination of utility-owned resources and a power purchase agreement with the Sierra Pacific Power Company d/b/a NV Energy (NV Energy). Although the 2016 NV Energy Services Agreement originally had a term through December 2020, Liberty states that it elected to terminate the agreement early (in May 2019), and will replace the existing supply agreement through short-term, competitively sourced bridging agreements, followed by one or more competitive solicitations for utility-owned RPS compliant resources. Liberty states that it will follow applicable Commission requirements to obtain approval of any proposed utility-owned projects. For the current compliance period, Liberty anticipates meeting the majority of its RPS compliance obligations with RECs from its Luning and Turquoise solar projects and plans to address any incremental REC need through the purchase of unbundled RECs.

Liberty asks the Commission for the authority to execute contracts developed through an expedited short-term competitive process in order to provide new bridge supplies given the early termination of its NV Energy Services Agreement. After the bridging arrangements are in place, Liberty states it will move quickly move to undertake one or more solicitations for renewable energy resources and storage facilities for Commission review and approval, in furtherance of its goal to become the first IOU to serve its customers with 100 percent renewable energy.

12. Community Choice Aggregators (CCA)

All current CCAs are identified in the Summary section of this decision. All the CCAs that were required to file draft RPS Procurement Plans did so. Many of the CCAs' RPS Plans provided minimal information and some used the same boilerplate language that lacked adequate detail. Most of the CCAs included cost information and some information on their plans to procure renewable energy, but several CCAs omitted important details. Table 5 below provides a summary of the CCAs' submissions and shows for each CCA whether aspects of the *2019 ACR* are missing. With their final 2019 RPS Procurement Plans due no later than 30 days after the effective date of this decision, the CCAs listed with missing details shall furnish the required details, including long-term contracting detail as discussed below. The CCAs must include all missing details set forth in *2019 ACR.*

Table 5: CCA Procurement Plan Compliance[21]

CCA	Served Draft Plan	Filed Draft Plan	Cost Info Provided	LCBF Info Provided
Apple Valley Choice Energy	x	x	x	x
City of Baldwin Park	x	x	-	x
City of Commerce	x	x	-	-
City of Hanford	x	x	-	x
City of Palmdale	x	x	-	x
City of Pomona	x	x	-	x
City of Santa Paula	-	-	-	-
Clean Power Alliance (LA County)	x	x	x	-
CleanPowerSF (San Francisco CCA)	x	x	x	x
Desert Community Energy	x	-	-	x
East Bay Clean Energy	x	x	x	x
King City Community Power	-	x	-	-
Lancaster Choice Energy	x	x	x	x
Marin Clean Energy	x	x	x	x
Monterey Bay Community Power	x	x	x	x
Peninsula Clean Energy	x	x	x	x
Pico Rivera Innovative Municipal Energy	x	x	x	x
Pioneer Community Energy	x	x	x	x
Rancho Mirage Energy Authority	x	x	x	x
Redwood Coast Energy Authority	x	x	x	x
San Jacinto Power	x	x	x	x
San Jose Clean Energy	x	x	x	x
Silicon Valley Clean Energy	x	x	x	X
Solana Energy Alliance	x	x	x	x
Sonoma Clean Power	x	x	x	x
Valley Clean Energy (City of Davis)	x	x	x	-
Western Community Energy of Seven Cities	x	x	-	x

Legend: (x) means filed; (-) means did not include

All CCAs assert that they will meet RPS requirements, but many include forecasts that show that, based on existing contracts, they are currently below

[21] As discussed elsewhere in this decision, the long-term contracting requirements apply to CCAs and the final Plans must demonstrate compliance or detail a path to achieving compliance.

future requirements. Some CCAs note that they plan to procure in the near future (*e.g.*, Clean Power SF) but others state they have no immediate plans to issue a solicitation (*e.g.*, Lancaster). Some CCAs have no RPS procurement to report because they will not start procurement until after 2020.

Some CCAs also give scant detail on risk and their Minimum Margin of Procurement (MMoP), which ensures they are protected from under procurement. The following two tables contain an analysis of each CCA's submissions:

Table 6: Overview of CCA Risk Assessment

Robust Risk Assessment	Minimal Risk Assessment	No Risk Assessment
East Bay Community Energy Robust description of risk modeling; Utilizes deterministic and probabilistic assessments.	**Apple Valley Choice Energy** Uses track record and 2% margin of over procurement. May consider a quantitative approach in the future.	**City of Baldwin Park** Intends to use qualitative approach of track record of suppliers and consider additional information as needed.
Peninsula Clean Energy High-level description of risk assessment process but indicates that PCE has a multi-prong approach including quantitative and assessment modeling for project's expected delivery, generation & economics; Manages risk through contracting; Requires daily, monthly, annual forecasts during operation; Over-procures past RPS requirements; Has diverse project technology types.	**Clean Power Alliance** Considers technology failure rates; Doesn't use historical trends; Perceives a low risk due to a high level of over-procurement, but majority of the potential risks are met with the procurement of short-term energy supply contracts.	**City of Commerce** Same information provided as Baldwin Park.

Robust Risk Assessment	Minimal Risk Assessment	No Risk Assessment
CleanPowerSF Current: 50% RPS goal; Plans to exceed SB 100 goals (100% by 2030); Uses comprehensive enterprise risk management framework; Portfolio risk management; Uses a hybrid of stochastic and deterministic modeling techniques.	**Lancaster Choice Energy** Uses Portfolio Risk management approach, focuses on choosing highly experienced/financially viable suppliers to avoid risk; States that a quantitative assessment is unnecessary; Short-term market is robust enough to address shortfalls.	**Desert Community Energy** No Risk Assessment performed because they have not done any procurement yet; Plans to use qualitative (Track Record) & Quantitative (price and generation profile) for risk assessments in the future.
Silicon Valley Clean Energy Authority Uses a portfolio risk management approach; seeking suppliers with strong track records but detailed in its approach; Used stochastic scenario modeling with PowerSimm related to meeting long-term goals; Hedges risk with its local goal of 50% RPS	**Marin Clean Energy** Uses a portfolio risk management model; Strong focus on identifying suppliers with strong track-records so a quantitative risk assessment doesn't seem critical; hedges risk with its local goal of 60% RPS (2018 achieved 62%); Continues to evaluate the need for quantitative risk.	**City of Hanford** Same information provided as Baldwin Park
Sonoma Clean Power Authority Describes a robust risk assessment process; Notes potential delay for projects and assumes it can replace with short term resources – raises questions about competition in the short-term market for existing resources if an increased number of market participants use this approach.	**Monterey Bay Community Power** Largely deterministic modeling; focus on using experienced developers; Utilizes a portfolio risk management approach for low cost-technology balanced portfolio; Large focus on cost risks associated with RPS procurement.	**King City Community Power** Doesn't believe it is necessary to do complex modeling; Assumes contracts have no risk due to procurement of existing resources; States that if generation output is lower than expected, it has time to replace it.
	Pico Rivera Innovative Municipal Energy Uses qualitative track record of developers and a 2% margin of over procurement. May consider quantitative approach in the future.	**City of Palmdale** Same information provided as Baldwin Park

Robust Risk Assessment	Minimal Risk Assessment	No Risk Assessment
	Pioneer Community Energy Focus is on minimizing risk through choosing experienced suppliers; Uses portfolio risk management of low cost - resource diversity; Monitors customer usage; Will consider the use of quantitative tools in the future.	**City of Pomona** Same information provided as Baldwin Park
	Rancho Mirage Energy Authority Uses qualitative track record of developers and a 2% margin of over procurement. May consider quantitative approach in the future.	**Western Community Energy of Seven Cities** No information provided on risk assessment aside from noting that generation variability and resource availability impacts their overall portfolio. No risk assessment performed.
	Redwood Coast Energy Authority Adopted 100% local renewables target by 2030 and 100% clean/green by 2025; Adopted internal Risk Management Policy; Uses a spreadsheet-based financial model to run various scenarios with a fulfillment calculator; Developed portfolio risk management tools.	
	San Jacinto Power Uses qualitative track record of developers and a 2% margin of over procurement. May consider quantitative approach in the future.	

Robust Risk Assessment	Minimal Risk Assessment	No Risk Assessment
	San José Clean Energy Manages risk at contractual level, prioritizes resource diversity, monitoring the market; Has a formal Risk Management policy in place.	
	Solana Energy Alliance High-level and ambiguous section, but seems to undertake qualitative and quantitative approaches and have various approaches to forecast modeling; Has a 50% local renewable target.	
	Valley Clean Energy Alliance States that because it does not have any long-term contracts, it has not conducted an assessment of its long-term renewable procurement. Describes goals of significantly exceeding RPS, over-procuring PCC 1 resources, and procuring fixed price volumes to hedge the availability of various resources; Includes detailed table of risk framework going forward.	

Table 7: CCA MMOP Status

Sets MMOP w/ Rationale	Minimal MMOP Arbitrary Rationale	No MMOP
Clean Power Alliance Expects to exceed RPS by at least 10% each year. Offers various products: RPS compliant, 50%, 100% (a majority of customers have elected 50 and 100%).	**Apple Valley Choice Energy** 2%MMOP not formally adopted by the CCA, but is the MMOP included in their Plan; All CalChoice member Plans have the same information on MMOP and provides no rationale for why 2% was chosen.	**King City Community Power** Will procure only what is required by law.
Sets MMOP w/ Rationale	**Minimal MMOP Arbitrary Rationale**	**No MMOP**

East Bay Community Energy 5% MMOP through 2020 and 2% starting in 2021. Exceeds the 2018 RPS requirement with 41.5% RPS; Will continue to evaluate but no rationale for how determined; Conducts scenarios in IRP.	**City of Baldwin Park** 2%MMOP not formally adopted by the CCA, but is the MMOP included in their Plan; All CalChoice member Plans have the same information on MMOP and provide no rationale for why 2% was chosen.	**Western Community Energy of Seven Cities** States it will typically over-procure to meet RPS, but nothing more.
Marin Clean Energy Local renewable goals are set above the current RPS requirement at 60%.	**City of Commerce** 2%MMOP not formally adopted by the CCA, but is the MMOP included in their Plan; All CalCHoice member Plans have the same information on MMOP and provide no rationale for why 2% was chosen.	
Monterey Bay Community Power Focus is to achieve RPS target plus a 2-5% cushion based on perceived operational risks; Default product is 34% RPS; Offers an 100% product.	**Desert Community Energy** No MMOP but expects to exceed through 2026 because of 50% goal.	
Peninsula Clean Energy Current: 50% renewables with a 100% customer option; 2025 goal is 100% renewables*; Procures at least 20% over the RPS requirements. **Doesn't clarify whether all RPS eligible*	**City of Hanford** 2%MMOP not formally adopted by the CCA, but is the MMOP included in their Plan; All CalChoice member Plans have the same information on MMOP and provide no rationale for why 2% was chosen.	
Redwood Coast Energy Authority Adopted 100% local renewables by 2030 and 100% clean/green by 2025; Plans to slightly procure above its Voluntary MOP as a cushion; It will use short term contracts to supplement, if needed.	**Lancaster Choice Energy** 2%MMOP not formally adopted by the CCA, but is the MMOP included in their Plan; All CalChoice member Plans have the same information on MMOP and provide no rationale for why 2% was chosen.	
Sets MMOP w/ Rationale	**Minimal MMOP Arbitrary Rationale**	**No MMOP**

CleanPowerSF States its MMOP ranges from 10%-17%, depending on year. City goals exceed the RPS requirements through 2030. City set 50% RPS eligible goal in 2017 and reached 48% in 2018; Includes information on MMOP methodology, inputs and scenarios.	**City of Palmdale** 2%MMOP not formally adopted by the CCA, but is the MMOP included in their Plan; All CalChoice member Plans have the same information on MMOP and provide no rationale for why 2% was chosen.	
San José Community Energy No official MMOP, but over-procures with higher target than RPS based on local policies of 45% RPS and 80% GHG free, until it catches up with law when it then tracks the requirements.	**Pico Rivera Innovative Municipal Energy** 2%MMOP not formally adopted by the CCA, but is the MMOP included in their Plan; All CalChoice member Plans have the same information on MMOP and provides no rationale for why 2% was chosen.	
Silicon Valley Clean Energy Uses its over-procurement of 50% RPS-eligible procurement from local goal to satisfy MMOP.	**Pioneer Community Energy** 2% MMOP but says not formalized, yet seems to apply it in their RNS calculation. This should be clarified. States that it could update their MMOP annually.	
Solana Energy Alliance Its 50% RPS procurement goals exceed RPS and uses that as its margin of over procurement.	**City of Pomona** 2%MMOP not formally adopted by the CCA, but is the MMOP included in their Plan; All CalChoice member Plans have the same information on MMOP and provides no rationale for why 2% was chosen.	

Sets MMOP w/ Rationale	Minimal MMOP Arbitrary Rationale	No MMOP
Sonoma Clean Power Committed to delivering 50% by 2020 and shows over-procurement in MMOP in RNS calculations.	**Rancho Mirage Energy Authority** 2%MMOP not formally adopted by the CCA, but is the MMOP included in their Plan; All CalChoice member Plans have the same information on MMOP and provides no rationale for why 2% was chosen.	
Valley Clean Energy Alliance MMOP related to large portion of over-procurement	**San Jacinto Power** 2%MMOP not formally adopted by the CCA, but is the MMOP included in their Plan; All CalChoice member Plans have the same information on MMOP and provides no rationale for why 2% was chosen.	

Many CCAs suggest that there should be an "on-ramp" for the long-term contracting requirement. We decline that request at this time because the statute does not provide for such a ramp-up process. Further, while the current long-term contracting requirement under Public Utilities Code Section 399.12(j) requires only a small portion of long-term contracts in an LSE's portfolio, SB 350 changed the requirement to 65 percent of total procurement. Public Utilities Code Section 399.13(b). While the new requirements do not take effect until 2021, we are concerned whether all CCAs are on target to comply with the long-term contracting requirement on schedule.

Table 8 below is an analysis of the CCAs' progress toward meeting the RPS statute's long-term contracting requirement, with those appearing to be on track to meeting the requirement as giving the Commission low concern and those farthest from meeting it as giving us high concern. While we do not take action based on the data in this chart, we will continue to monitor progress toward long-term contracting carefully for all LSEs.[22] All CCAs shall demonstrate their plans to meet the long-term contracting requirement in SB 350 in their 2020 RPS Procurement Plans. They shall describe the specific actions they plan to take to meet the requirement and give a timeline for each proposed action.

Table 8: CCA Long-Term Contracting Positions (Including Launch Year)

Low Concern: Achieved ≥ 65% Long-Term Contracts[23]	**Medium Concern: Achieved < 65% Long-Term Contracts**	**Serious Concern: No LT Contracts**
Clean Power Alliance (2018)	Apple Valley Choice Energy (2017)	City of Baldwin Park (2020)
CleanPowerSF (2016)	San Jose Clean Energy (2018)	City of Commerce (2020)
East Bay Community Energy (2018)		City of Hanford (2020)
Lancaster Choice Energy (2015)		City of Palmdale (2020)
Monterey Bay Community Power (2018)		City of Pomona (2020)
Marin Clean Energy (2010)		Desert Community Energy (2020)
Peninsula Clean Energy (2016)		King City Community Power (2018)
Redwood Coast Energy Authority (2017)		Pico Rivera Innovative Municipal Energy (2017)
Rancho Mirage Energy Authority (2018)		Pioneer Community Energy (2017)

[22] SB 155 (2019, Bradford) will require action in the future.

[23] Positions shown are based on contracting to date. As noted above, additional contracting by CCAs will need to be done, including additional long-term contracts, but those with "low concern" are showing that in their current portfolios that they do have a majority of expected procurement committed from long-term contracts.

Footnote continued on next page.

Low Concern: Achieved ≥ 65% Long-Term Contracts[24]	**Medium Concern: Achieved < 65% Long-Term Contracts**	**Serious Concern: No LT Contracts**
Sonoma Clean Power (2014)		San Jacinto Power (2018)
Silicon Valley Clean Energy (2017)		Solana Energy Alliance (2018)
		Valley Clean Energy Alliance (2018)
		Western Community Energy of Seven Cities (2020)

In summary, many CCAs continue to provide scant information as noted in 2018 RPS Procurement Plan decision, D.19-02-007, and the recent CCA-specific decision, D.19-09-007. All CCAs with missing information as set forth in Table 5 above shall remedy the omissions in their final 2019 RPS Procurement Plans due no later than 30 days following Commission issuance of this decision. While each of the foregoing decisions accepted incomplete CCA 2018 Plans, we stated in each decision that the Commission would not approve the Plans in 2019 unless they contain the missing information. Therefore, this decision does not accept as final the Plan of any CCA with missing data as shown in Table 5. We will assess the final Plans when they are submitted and, if necessary, take action at that time.

Finally, in their 2020 RPS Procurement Plans, the CCAs in column 3 of Tables 6 and 7 shall furnish more information about their risk reduction and MMoP strategies.

[24] Positions shown are based on contracting to date. As noted above, additional contracting by CCAs will need to be done, including additional long-term contracts, but those with "low concern" are showing that in their current portfolios that they do have a majority of expected procurement committed from long-term contracts.

13. Electric Service Providers (ESP)

The ESPs are identified in the Summary section of this decision. Pursuant to the *2019 ACR*, these companies were required to, and in fact did, submit RPS Procurement Plans that provided the information required in Sections 5.1-5.6, 5.8, and 5.11-5.13 of the *2019 ACR*. However, of the twenty-three ESPs, only Agera Energy, LLC[25] and The Regents of the University of California provided the cost information required in Section 5.10. Further, many of the ESP RPS Plans provided minimal information, while some used boilerplate language that lacked adequate detail. Finally, while most ESPs note that they will meet the long-term contracting requirements, few actually explain how they plan to meet the requirement or show that they have executed long-term contracts.

Table 9 below provides a summary of the ESP submissions, including those elements of *2019 ACR* that are missing by ESP. ESPs that failed to include the required elements must correct these omissions within their final 2019 RPS Procurement Plans. Of the twenty-three ESPs, six currently do not serve any retail load. Pursuant to D.13-11-024, it is reasonable not to require an ESP to file a procurement plan if they do not serve any retail load.[26] The exemption will expire if and when a non-load serving ESP begins or resumes serving load in California and thereby incurs RPS procurement obligations. This exception does not exempt the non-load serving ESPs from filing RPS Compliance Reports or making submissions other than the RPS Procurement Plan itself, in order to ensure accurate record-keeping and account for the potential of serving load during a portion of the compliance period.

[25] Recent filings served on the Commission indicate Agera Energy is in bankruptcy. The Commission is monitoring the bankruptcy proceeding separately.

[26] D.13-11-04 COL 28.

Table 9: ESP Procurement Plan Compliance

ESP	Cost Info Provided	LCBF Info Provided	Long-Term Contract Info Provided	Minimum Margin of Procurement Info Provided	Price Adjustment Mechanism Provided	Quantitative Info. Provided	Addressed IRP
3 Phases Renewables	-	-	X	X	X	X	X
Agera Energy, LLC	X	-	X	-	-	X	X
American PowerNet Management, LP	-	X	X	X	X	X	X
Calpine Energy Solutions	-	X	X	X	X	X	X
Calpine PowerAmerica-CA, LLC	-	X	-	X	X	X	-
Commercial Energy of California	-	X	X	X	X	-	-
Constellation New Energy, Inc	-	X	X	X	X	X	X
Direct Energy Business	-	X	X	X	-	X	X
EDF Industrial Power Services (CA), LLC	-	-	X	X	X	X	X
Gexa Energy California, LLC	-	X	-	X	X	X	-
Just Energy Solutions	-	X	X	X	X	X	-
Liberty Power Delaware LLC	*	*	*	*	*	*	*
Liberty Power Holdings LLC	-	X	-	X	X	X	X
Mansfield Power and Gas, LLC	*	*	*	*	*	*	*
Palmco Power CA	*	*	*	*	*	*	*
Pilot Power Group, Inc.	-	X	X	X	X	X	X
Praxair Plainfield, Inc.	*	*	*	*	*	*	*
Shell Energy	-	X	X	X	X	X	X
Tenaska California Energy Marketing, LLC	*	*	*	*	*	*	*
Tenaska Power Services Co.	*	*	*	*	*	*	*
The Regents of the University of California	X	X	X	X	X	X	X
Tiger Natural Gas, Inc.	-	-	X	X	X	X	X
EnerCal USA, LLC (dba YEP ENERGY)	-	-	X	-	-	-	X

Legend: (x) means filed; (-) means did not include; (*) means provider exempt because not serving load

14. Party Comments on the 2019 Procurement Plans

14.1. Commenting Parties

In accordance with the timeline modified in the May 7, 2019 Administrative Law Judge's Ruling Modifying Schedule, the following parties submitted opening comments on July 19, 2019: CalWEA; Shell Energy; PG&E,

SCE, and SDG&E, jointly; IEPA; AWEA-California; CASMU; SBUA; Cal Advocates; and CalChoice. On August 2, 2019, the following parties submitted reply comments: PG&E, SCE, and SDG&E, jointly; PG&E, SCE, and SDG&E, individually; AReM; Cal Advocates; Joint CCA Parties; and AWEA-California. The comments on the 2019 Procurement Plans raised the issues that are discussed below.

14.2. Discussion of Issues Raised in Comments

14.2.1. Staff Reports on Aggregate RPS Net Short and Long-Term Contracts for all Retail Sellers

AWEA asserts that the Commission should publicly aggregate RPS net short and long-term contract data for all retail sellers by Transmission Access Charge (TAC) area in a staff report. IEP asks the Energy Division to aggregate the 2019 Plan data to provide a transparent overview of retail seller procurement from now to 2030, claiming there is a risk of double counting planned procurement when CCAs report total numbers instead of their own portion of a joint solicitation.

We reject this request for further staff reporting; staff already regularly reports on RPS progress. The RPS Annual Report[27] to the legislature provides detailed updates on the progress and status of LSEs' compliance with RPS program requirements. With respect to double counting, LSEs only may include their own portion of a joint procurement contract in their RPS procurement reporting, which is reviewed by Energy Division staff annually.

[27] The RPS Annual Report can be found on the CPUC's RPS website at this link: https://www.cpuc.ca.gov/RPS_Reports_Data/

14.2.2. Merge RPS Procurement Plans and Compliance Reports

Shell and AReM ask the Commission to merge two separate reports into one – the annual RPS Procurement Plans and the annual RPS Compliance Reports. They assert it would streamline the process for LSEs. The IOUs oppose this suggestion, asserting the two filings serve different purposes. The Plans are forward looking while the Compliance Reports serve to demonstrate retail seller compliance with enforceable program requirements based on historic data.

We agree with the IOUs' comments, as the filings are fundamentally different, contain different information, and are required by two separate statutes (Sections 399.13(a)(3) and 399.13(a)(5)). Compliance reports are for determining compliance with the RPS program based on historical verified procurement, while procurement plans are used to assess portfolio supply and demand, compliance delays, planned solicitations, project failure risk, and similar real time or future events.

However, it may make sense to examine the two filings and ensure that they are as streamlined as possible. Therefore, we ask Energy Division to initiate stakeholder workshops before filing of the 2020 draft RPS Procurement Plans to discuss whether there are redundancies within the Procurement Plans and Compliance Reports. This task last occurred in 2015, so it makes sense to revisit the issue.

14.2.3. Flexibility in Applying the Long-Term Contracting Requirement for New Retail Sellers

MCE, AVCE, Commerce, Hanford, Palmdale, Pomona and LCE ask for flexibility in long-term contracting, while IEP, the Joint IOUs, CalWEA, AWEA, and Cal Advocates oppose the proposal. Supporters assert that the long-term contracting requirements pose a "substantial financial risk" for all LSEs but new

LSEs in particular. They propose an on-ramp process where the percentage would be lowered for new LSEs and gradually increased to the 65% required by the RPS statute over time.[28] Opponents assert that the proposal is inconsistent with statute and with prior Commission implementation of the long-term contracting requirement. The Joint IOUs also assert such a change would create a regulatory loophole for new LSEs. CalWEA urges the Commission to dispel the notion that it will relax the long-term contracting requirement; IEP believes lack of transparency on how and when retail sellers will meet compliance with the 65 percent long-term contracting requirement is a "glaring hole" in the Plans and AWEA asserts the long-term contract requirement applies to all LSEs regardless of their start of service date.

We agree with Cal Advocates and others that the long-term contracting requirement is statutorily required, and therefore we do not have the authority to waive it for certain retail sellers. Further, we have already stated our intention to ensure all LSEs that wish to participate in this important market comply with its rules.[29] LSEs whose draft Plans do not demonstrate compliance with the long-term contracting requirement must bring them into compliance or detail a path to achieving compliance in their final Plans due on or before 30 days from the date of Commission issuance of this decision.[30]

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[28] Pub. Util. Code § 399.13(b) ("(b) A retail seller may enter into a combination of long- and short-term contracts for electricity and associated renewable energy credits. Beginning January 1, 2021, at least 65 percent of the procurement a retail seller counts toward the renewables portfolio standard requirement of each compliance period shall be from its contracts of 10 years or more in duration or in its ownership or ownership agreements for eligible renewable energy resources.").

[29] *See, e.g.,* D.17-06-026, as modified by D.17-11-037 (setting forth compliance rules) and D.19-08-007 (applying rules).

[30] The retail sellers who must come into compliance are MCE, AVCE, Commerce, Hanford, Palmdale, Pomona, and LCE. All but MCE are clients of CalChoice.

14.2.4. Jurisdiction to Require all Retail Sellers to Provide RPS Cost Information

The Joint IOUs note that several LSEs have refused to provide required cost quantification data, citing jurisdictional limitations. AReM asserts that the requirement to provide cost quantification information applies to the IOUs, but not to non-IOU LSEs, citing Public Utilities Code Sections 913.3 and 913.4. AReM also claims that ESPs are not public utilities subject to Commission rate or ratemaking oversight, citing D.05-11-025 at 12.

We agree with the Joint IOUs and reject the other LSEs' jurisdictional arguments. As the Commission reiterated in a decision rejecting a similar argument by Shell in D.19-09-007:

> The Commission considered and rejected Shell's jurisdictional argument in its decision on the Power Charge Indifferent Adjustment (PCIA) paid by customers of CCAs and ESPs, and we reiterate excerpts of that decision here. CCAs and ESPs are required to submit cost information in several programs, including RPS:
>
> [Shell and others'] arguments fail for several reasons. Mostly they conflate the Commission's inability to set their prices with our duty to collect that price information....
>
> The Commission has jurisdiction over long term procurement of energy resources that will supply energy service when and where needed. The Commission is also charged with developing Demand Response products encouraging distributed generation. This jurisdiction is so comprehensive that it includes questions of public health and safety arising from our duty to assure that customers receive adequate utility services at just and reasonable rates and justifies our direction that [Load Serving Entities] must provide the information to the Commission. (*See* Cal. Const, Art. 12; Public Utilities Code § 451; *P.G.&E. Corporation v. Public Utilities Commission* (2015) 237 Cal.App.4th 812.)

In addition to that comprehensive jurisdiction, this Commission is obligated to study the [Resource Adequacy (RA)] market and to report to the legislature costs relating to the RPS program. Public Utilities code Section 380(b)(1) requires the Commission to:

(b) In establishing resource adequacy requirements, the commission shall achieve all of the following objectives:

(1) Facilitate development of new generating capacity and retention of existing generating capacity that is economic and needed....

These same parties are also required to provide RPS cost data to enable "the commission [to] release to the Legislature for the preceding calendar year the costs of all electricity procurement contracts for eligible renewable energy resources, … ." More specifically, the "Director of Energy Division is authorized to require retail sellers to submit appropriate documentation, including but not limited to copies of renewables portfolio standard procurement contracts, to support the information in any report submitted." And the Director of Energy Division has, in fact, required submission of those contracts. Again, given the information sought by this Decision is needed to satisfy the Commission's obligation to comply with the RPS program, among other obligations, the ESPs and CCAs already have a duty to provide this information.

Contrary to the position that the Commission has no jurisdiction to obtain pricing information or is attempting to "expand [the Commission's] regulatory control over the activities of ESPs," the duties imposed on the Commission are separate and apart from a CCAs' or ESPs' ability to set their own prices paid or charged. In other words, the Commission's requiring the data, and the ESPs' and CCAs' providing the data, has nothing to do with setting ESPs' or CCAs' retail rates. Actual contract prices provide the most accurate and timely indications of current and forward energy supply conditions, which are clearly within the Commission's jurisdiction to require.

Based on the Commission's comprehensive jurisdiction over the state's long-term energy supply portfolio, [Shell and others']

> position that the Commission cannot require ESPs or CCAs to reveal contract/price information ... requires a crabbed and incomplete reading of the Public Utilities Code. D.19-09-007, at 17, citing D.18-10-019 at 74.[31]

Parties that continue to disregard the clear order of this Commission that they provide RPS procurement cost information are at risk of enforcement action by this Commission. Any LSE that has not provided the information required in the *2019 ACR* shall furnish such information with its final 2019 RPS Procurement Plan or risk such enforcement.

14.2.5. Standard Annual Data Request for Cost Information

The Joint IOUs propose to transition cost quantification information required in LSEs' RPS Procurement Plans to a process in which LSEs compile cost information and submit it to the Commission via a standard data request response. The response would include the same information required in the *2019 ACR* and would be provided no later than July 1 each year. The Joint CCAs support the proposal for cost quantification to be submitted in an annual data request response including the same information as in the current cost quantification table. We reject the suggestion to change the current process, which requires a public filing listed on the docket card for this proceeding. Public access to the cost information, with appropriate confidentiality protection for limited parts of the submission, is the best way to ensure transparency. There may be a way to streamline submissions if and when RPS and IRP filing

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[31] The Commission also has authority to provide the information discussed in this decision pursuant to Pub. Util. Code § 701. Applications for Rehearing of D.18-10-019 are currently pending. Reference to D.18-10-019 is not intended to either dispose of these rehearing applications or to prejudge them.

requirements are combined, but we express no opinion here on the usefulness of such a change.

14.2.6. The Commission Should Direct LSEs to Use IRP Data to Estimate their Curtailment Rates

CalWEA and SBUA ask the Commission to direct LSEs to use curtailment rates developed from the IRP process.

Curtailment rate or frequency refers to how often the IOUs directed curtailment of contracted resources. CalWEA and SBUA suggest that the Commission calculate curtailment rates for LSEs for each technology by comparing curtailment rates in the IRP base case to those in the adopted 2030 IRP. SBUA asserts that the IRP proceeding could produce a table illustrating the percentages of curtailment by technology type, zone and year. Further, discounting renewables that are likely to be curtailed could encourage LSEs to build new renewables in areas least subject to curtailment. The Joint IOUs and Joint CCA Parties oppose this suggestion. The IOUs claim that the IRP data are not sufficient for use in the RPS proceeding and that the RESOLVE model used in IRP does not support use for RPS Plans. They also suggest that LSEs have flexibility to propose other LSE-specific curtailment modeling. The Joint CCA Parties argue that the curtailment rates developed in the IRP are too aggregated for LSEs.

We agree with the Joint IOUs and Joint CCA Parties that the IRP-generated curtailment values are too aggregated at this time to provide guidance on individual LSEs' procurement decisions. The variability of curtailment is such that extrapolating system projections and applying them to individual LSEs' portfolios will almost certainly result in inexact curtailment forecasts. That is, because negative pricing and curtailment rates are locational, LSEs should analyze the impact of oversupply events on their individual resource portfolios to inform their procurement decisions.

14.2.7. The Commission Should Encourage All LSEs To Fully Participate in Economic Dispatch

CalWEA argues that it is important that all LSEs use their economic curtailment rights to avoid imposing negative pricing on the rest of the market and potentially triggering reliability events that could be caused by overgeneration. Further, CalWEA asserts that rather than calling for relaxed RPS requirements, imposing negative pricing on other market participants, or threatening system reliability any new retail sellers that fear that they may not be able to meet their RPS requirements should postpone their start-of-service dates until they are ready to fully incorporate all RPS requirements in their planning and operations, including building in appropriate procurement margins above required levels, which should account for appropriate levels of economic curtailment. The Joint CCA Parties agree that economic dispatch can help efficiently manage generation reductions, but each LSE does not face the same balance of renewable compliance obligations and pricing risk. They state that small LSEs with non-dispatchable renewable resources may have a different compliance tolerance for curtailment than a larger LSE with more diverse renewable resource types.

We agree with CalWEA use of economic curtailment rights could reduce occurrence of reliability events. We also agree though with the Joint CCA Parties that different LSEs may have different tolerances for curtailment. In addition, LSEs may have differing capabilities regarding being able to economically dispatch resources in their portfolio. Thus, we do encourage use of economic dispatch but do not require full participation. As the IOUs noted in their 2019

RPS Plans, curtailment is increasing, and CAISO's Generation Deliverability Initiative may cause further increases of curtailment for new resources.[32] Curtailment frequency, cost, and forecasting requirements, as directed by Sections 399.13(a)(5)(B) and 399.15(b)(5), are a new reporting requirement for the 2019 RPS Procurement Plans submitted by ESPs and CCAs per the *2019 ACR*. Given the potential impact to the system, LSEs' ability to meet RPS requirements, and ratepayer costs, we expect all LSEs to provide a thorough analysis of their overall strategy for minimizing risk to ratepayers.[33]

14.2.8. Some CCAs Are Using Boilerplate Language That Lacks Adequate Detail In Their Procurement Plans

Several CCAs filed their Plans using the same language word for word across different programs. Two versions were used:

- CalChoice text which includes the following sections/areas: Assessment of RPS portfolio supplies and demand; Risk assessment; Bid solicitation protocol; Minimum margin of procurement; Consideration of price adjustment mechanisms; Curtailment; Safety considerations; and
- The Energy Authority text which includes the following sections/areas: Compliance delays; Risk assessment; Bid solicitation protocol; Consideration of price adjustment mechanisms; Curtailment; Safety considerations.

We do not require every LSE to submit a Plan containing different information, but each RPS Plan should be specific to the individual LSE as each has a specific location, load, and procurement requirement. As a result of the use

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[32] CAISO Generation Deliverability Assessment Initiative: http://www.caiso.com/informed/Pages/StakeholderProcesses/GenerationDeliverabilityAssessment.aspx.

[33] *See also* Pub. Util. Code § 399.13(a)(5)(F).

of generic language, some of the CCAs' Plans fail to furnish required detail and they need to furnish additional information in their final 2019 RPS Procurement Plans as set forth in Section 12 above.

14.2.9. IOUs' Informational-Only Time Of Delivery (TOD) Factors

As discussed above, PG&E, SCE and SDG&E seek adoption of a joint informational-only TOD submission based on the marginal energy cost calculated in their GRC every three years. They base the request on confidentiality needs stemming from the Commission's confidentiality decision, D.06-06-066, as modified. This submission would eliminate the historic use of TOD factors for project valuations and contract costs.[34] In the 2018 RPS Plan decision, D.19-02-007, the Commission approved the use of informational-only TOD factors and ordered the IOUs to develop a proposal for implementation within 90 days. The decision reasoned that IOU TODs should "communicate to developers when energy deliveries might be more valuable to the system and allow developers to respond with optimized project designs and bids."[35] The IOUs filed their joint proposal on May 29, 2019; no party commented on the proposal.

The IOUs joint proposed methodology is approved. PG&E's and SCE's informational-only TOD factors proposed in their 2019 draft RPS plans, however, must be modified. Current proposed inputs are up to five years out of date. Thus, both PG&E and SCE shall include in final 2019 RPS plans new informational-only TODs that are based on the most recent inputs that are

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[34] IOU Joint Submittal of Informational-only Time of Delivery Proposal in Compliance with D.19-02-007 (available at http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=309941761).

[35] D.19-02-007 at 98.

available. In future years' filings the IOUs shall also provide workpapers to confirm there is a high correlation between the public informational-only TOD factors and confidential IOU forecasts.

14.2.10. Staff to Evaluate Project Development Success Rate

IEP asserts that many LSEs' RPS plans seem to assume a 100 percent success rate, whereas SCE assumes a 70 percent success rate. IEP states that planned procurement of LSEs of 2,500 MW by 2023 might only be 1,750 MW if 30 percent of those project fail. Thus, IEP asks that the Commission evaluate the actual project development success rate. SBUA partly agrees with IEP but asserts that that LSEs should not have to over-procure to meet 2023 goals as wind and solar projects can be built quickly and those project failures can be replaced.

We reject IEP's recommendation at this time. We agree that LSEs should incorporate a project success rate into their RPS planning to help accurately plan for the long term. However, the rate is likely LSE-specific because they sellers have different portfolios, and IOUs' project development success has changed over time.[36] Thus, it is difficult to see the usefulness of the requested evaluation given the differences among LSEs and for individual LSEs over time.

14.2.11. IOUs' REC Sales Frameworks

The sections of this decision describing each of the three large IOUs' Plans set forth these IOUs' mostly confidential proposals for new REC sales. Cal Advocates and SBUA oppose each such proposal, as described below. This section summarizes the parties' positions, and we also discuss the proposals in

[36] For example, SCE's assumption in 2016 was a 60% success rate, compared to the 70% assumption in this year's Plan.

greater detail in connection with the three large IOUs' individual 2019 RPS Procurement Plans.

Large IOU Draft REC Sales Proposals

Each IOU was required to include in its 2019 RPS Plan a solicitation protocol if it was planning on conducting a sales solicitation, including a framework for determining the quantity of RPS volumes to sell in a given solicitation, the target price, and the price floor. As noted above all three large IOUs propose to conduct sales solicitations. The following sections describe each of the three large IOUs' REC sales proposals in further detail and the party comments received regarding the proposals.

PG&E's Draft Plan: Through its 2019 Plan, PG&E seeks to update its sales framework by changing the volume of RECs it proposes to sell and the pricing, with most details marked confidential. PG&E proposes that the updated RPS sales framework apply to the two to three solicitations it plans to hold for RECs that would be delivered in 2020-2021. PG&E also asks the Commission make PCC classification determinations when approving RPS sales agreements. We reject this proposal because the PCC determination can only be made after the actual energy is delivered, as specified in D.11-12-052.

SCE's Draft Plan: SCE seeks authorization to sell large volumes of short-term RECs, with most of the details marked confidential. Certain types of sales would be pre-approved, as described in Section 9.7. SCE also seeks to sell RECs in all three PCC categories, modify its price floor methodology, and enhance its use of brokers and exchanges to sell RECs. SCE may also pursue bilateral contracts that do not use the *pro forma* agreement or have a term beyond 2024; in either case SCE will submit a Tier 3 Advice Letter. SCE also seeks approval to submit RPS sales contracts in its Energy Resource Recovery Account (ERRA) proceeding, instead of via Advice Letters.

SDG&E's Draft Plan: SDG&E gives limited information, stating it will enter into solicitations to the extent they benefit customers. SDG&E also states that if it wishes to assign a long-term contract to another counterparty, it will utilize a Tier 2 Advice Letter for approval.

Party Comments on Draft Plans

Cal Advocates opposes the pre-approval for REC sales sought by SCE, preferring the use of Tier 1 Advice Letters.

On PG&E's proposal, Cal Advocates opposes several of the confidential details of the sales framework. Cal Advocates proposes an alternative methodology.

On the REC aspects of SDG&E's Plan, Cal Advocates and SBUA criticize the lack of detail in SDG&E's discussion required by question 7 of the *2019 ACR* (Bid Solicitation Protocol, Including Least Cost Best Fit Methodologies).

Discussion of REC Issues in Plans

PG&E*:* We approve PG&E's REC sales framework with modifications. The pricing PG&E seeks is rejected as potentially detrimental to ratepayers. PG&E may use the methodology proposed by Cal Advocates or its previously approved methodology. We also reject PG&E's proposal for the Commission to make a PCC classification determination when approving sales agreements. The PCC determination can only be made after the actual energy is delivered, as specified in D.11-12-052.

SCE*:* We approve SCE's REC sales framework with modifications to ensure the value of RECs are not affected unduly. The volume of RECs SCE seeks to sell is excessive. SCE's framework could make sense because it seeks to draw down its long REC position over multi-year compliance periods. However, because SCE's proposal for 2020 REC sales covers the last year of a compliance period, it cannot "ratably" draw down its over-procurement in the entire period.

Further, SCE proposes a methodology that may harm the value that REC sales provide to ratepayers. Coupled with SCE's problematic volume limit discussed above, under SCE's proposal RECs may flood the market and their value may quickly decline. Thus, we limit the sales volume on a per-vintage year basis and reject the limits of SCE's REC sales price floor methodology described in sections (i) and (iii) of its methodology and direct SCE to apply the limit in section (ii) of its methodology to section (i).[37]

We also reject SCE's proposal to shift IOU sales to brokers and exchanges. Bilateral and solicitations approved by Advice Letters still provide a market for sales while still allowing Commission oversight and stakeholder input. Indeed, we denied SCE's request to use brokers in D.11-04-030 and D.14-11-042, holding that all RPS transactions must be pre-approved.

SDG&E. We approve SDG&E's framework and request to conduct a potential RPS REC sales solicitation with modification. SDG&E's Plan does not provide limitations on the volume of sales or price of those sales. Therefore, SDG&E shall amend Section 9.D of its 2019 Plan to provide (1) a methodology for calculating maximum REC sales volumes for 2019, based on an analysis of its RNS, and (2) a detailed explanation of its REC sales pricing methodology, including a target price and price floor. Such information is required by the *2019*

[37] These sections appear in SCE's Draft 2019 RPS Procurement Plan, Appendix E, Section III, at 3. We have masked confidential details in this discussion.

ACR, Item 7. With regard to SDG&E's request to be allowed to assign RPS contracts to a third-party buyer, SDG&E shall seek such assignment via a Tier 3 (rather than Tier 2) Advice Letter, for consistency with how we approve long-term contracts that do not follow a standard contract.[38]

14.2.12. Cost Containment

Some parties repeat earlier requests for the Commission to develop a cost containment mechanism, citing Section 399.15(c). We are aware of the requirement, which has been delayed by new legislation and actions in other proceedings, such as IRP, but do not act on it here.

14.2.13. Confidentiality

Several parties ask the Commission to ensure that LSEs adhere to the requirements established in D.06-06-066, which set forth confidentiality rules for procurement, including RPS, and work toward applying the same requirements to all LSEs. Further, they recommend that the CPUC should provide specific guidance regarding what may be redacted. The parties reasoning for their request is that they assert that some LSEs are redacting beyond the protections set in D.06-06-066 which is causing a lack of transparency. We do note that D.06-06-066 is the guiding decision on confidentiality and it applies to all LSEs. The Commission has the ability to review and reject overly broad assertions of confidentiality.

14.2.14. Coordination of RPS and IRP Plan Filings

The *2019 ACR* proposes a process in which annual RPS filing requirements will be satisfied by the LSEs' filing of their IRP Plans.[39] This decision finds that

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[38] D.03-06-071 as modified by D.03-12-065 (establishes policy rules within six months of legislative effective date, per statute.)

[39] The IRP proceeding (R.16-02-007) is the primary venue for implementing the SB 100 requirements related to resource planning for the electric sector.

coordination between RPS and IRP proceedings, such as requiring RPS annual plans to be filed in IRP, will benefit the Commission and parties. Coordination is also supported by parties. However, the degree of coordination and the efficiencies achieved will depend on the amount of time spent in developing the coordination process. In addition, changing the procedure at this time could jeopardize the efficiency of the existing proceedings.

The following parties filed comments on the staff proposal presented in the 2019 ACR: AWEA-California; BVES; Cal Advocates; IEPA; Joint IOUs; Shell Energy; and CASMU. Reply comments on the staff proposal were filed by AReM; AWEA-California; Cal Advocates; Joint CCA Parties; Joint IOUs; and SBUA. In general, parties express support for closely aligning the RPS and IRP Plans as a means to:

a. Reduce the filing burden for small parties;
b. Make both RPS and IRP processes more efficient;
c. Facilitate a comprehensive review of resource planning and procurement;
d. Accommodate Commission staff and intervenor resource constraints; and
e. Comply with statutory and Commission annual filing requirements.

It is always our goal to avoid duplicative filings and reduce the burden on small parties or new market entrants. We therefore direct Energy Division to develop a comprehensive and practicable plan to combine IRP and RPS filings without jeopardizing the current timelines, allocation of Commission resources, or procedural efficiencies currently in place for IRP and RPS. The plan must include implementation details and identify the ways in which the combined IRP and RPS filing will meet the objectives identified in party comments (as listed above). To this end, Energy Division is authorized to hold workshops, establish working groups, prepare a white paper or staff proposal, and take such other actions as the Director of Energy Division may deem necessary. The Director of Energy Division shall issue progress reports on a quarterly basis and shall complete a staff proposal based on the foregoing process no later than August 2020. Progress reports and the staff proposal shall be served on the service lists for both RPS and IRP proceedings.

15. Conclusion Regarding Load Serving Entities' 2019 Procurement Plans

15.1. PG&E's 2019 RPS Procurement Plan

PG&E's 2019 draft RPS Procurement Plan contains each of the items required of such Plans, with some exceptions. With its final Plans, PG&E shall modify its Plan as set forth below. PG&E's request to forego a 2019 solicitation is granted. Should PG&E determine that an RPS solicitation or bilateral contracts are needed during the time period covered by the 2019 solicitation cycle, or prior to the Commission issuing a decision on the 2020 RPS Procurement Plans, PG&E shall 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 2019.

PG&E's proposal for REC sales is approved with modification, as discussed in Section 14.2.11. The solicitation protocol, except for the proposed sales floor is approved. As noted above, PG&E may use the methodology proposed by Cal Advocates or its previously approved methodology.

PG&E's TOD filing, which was made jointly with SCE and SDG&E, is approved, but PG&E must update its informational-only TODs proposed in its 2019 RPS Plan with the most recent available inputs.

15.2. SCE's 2019 RPS Procurement Plan

SCE's 2019 RPS Plan satisfies the specific requirements for the 2019 RPS Procurement Plans that were set forth in the *2019 ACR*, with exceptions noted below. Its request not to hold a 2019 solicitation is granted. Should SCE determine that an RPS solicitation or bilateral contracts are needed during the time period covered by the 2019 solicitation cycle, or prior to the Commission issuing a decision on the 2019 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 2019.

We grant in part and deny in part SCE's REC sales proposals. We decline to pre-authorize REC sales that meet SCE's specified volume, term limit and price constraints. SCE shall instead seek approval of REC sales through Tier 1 or Tier 3 Advice Letters as it has done in the past. As we stated in last year's RPS Procurement Plan decision, bilateral and solicitations approved by Advice Letters provide a market for sales while still allowing Commission oversight and stakeholder input. We also reject SCE's proposal to shift IOU sales to brokers and exchanges. Indeed, we denied SCE's request to use brokers in D.11-04-030 and D.14-11-042, holding that all RPS transactions must be pre-approved. Additionally, SCE's sales framework shall be modified as indicated above.

Lastly, we find that SCE's description of the treatment of workforce development and disadvantaged communities in its LCBF methodology lacks sufficient detail. SCE shall include more information on the treatment of workforce development and disadvantaged communities in its Final RPS Procurement Plan.

15.3. SDG&E's 2019 RPS Procurement Plan

We find that SDG&E's 2019 RPS Procurement Plan satisfies the specific requirement for 2019 RPS Procurement Plans that were set forth in the *2019 ACR*, with exceptions noted below, and that SDG&E's evaluation of its current RPS procurement needs relative to its request not to hold a 2019 solicitation is reasonable. Should SDG&E determine that an RPS solicitation or bilateral contracts are needed during the time period covered by the 2019 solicitation cycle, or prior to the Commission issuing a decision on the 2020 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 2019.

We also approve SDG&E's framework and request to conduct a potential RPS REC sales solicitation, subject to the modifications described above. SDG&E's request to be allowed to assign RPS contracts to a third-party buyer is approved; however, SDG&E shall seek such assignment via a Tier 3, rather than a Tier 2, Advice Letter.

15.4. Small and Multijurisdictional Utility Plans

The Draft 2019 RPS Plans by BVES and Liberty are approved, subject to the following modifications: Both BVES and Liberty must update their Plans to follow the required format outlined in Attachment B of the *2019 ACR*. Adhering to the required format will better enable parties, bidders, and the Commission to easily access, review and compare the numerous RPS plans filed every year.[40] In addition, per the *2019 ACR*, both BVES and Liberty must include a section

[40] 2019 ACR at 8.

addressing how their RPS Plan is responsive to "LSE Policies and Goals, Statutes, and Commission Policies," including the long-term contracting requirement enacted in SB 350. Finally, there are several sections in Liberty's Plan that appear to contain outdated information (for example, page 10 of Liberty's Plan states that the Turquoise Project is awaiting Commission approval; however, the Commission approved this project in D.17-12-008). Liberty shall make every effort to correct all outdated information in its final Plan.

Regarding Liberty's request for Commission approval to execute short-term contracts considering the early termination of the NV Energy Services Agreement, we grant Liberty's request subject to requirement in D.14-11-042 that each contract of less than five years be submitted via a Tier 1 Advice Letter.

Lastly, PacifiCorp filed its IRP and RPS supplement too late for comment. The Commission will address the timing and merits of PacifiCorp's October 13, 2019 IRP filing and the required supplement submitted on November 8, 2019 in a separate ruling and/or decision.

15.5. CCA Plans

Several CCAs have submitted Plans lacking adequate detail, as they did in 2018. In the decisions approving the 2018 Plans, the Commission made clear that these CCAs would be required to provide more detail in their 2019 Plans. The Commission stated that it would not approve these CCAs' 2019 Plans without such compliance. The Plans of CCAs that are missing required elements from the *2019 ACR* must include them in their final Plans, as described in this decision, or those Plans will not be approved.

15.6. ESP Plans

Similar to CCAs, most ESPs submitted Plans lacking required information. The Commission made clear in its decision approving the 2018 Plans that ESPs would be required to provide greater detail in their 2019 Plans, including information explaining how each ESP plans to reach their Net RPS Procurement Need.[41] Affected EPSs shall provide the missing detail (*See* Table 9) with their Final Plans no later than 30 days following Commission issuance of this decision. Parties that continue to disregard the clear order of this Commission to provide RPS procurement cost information are at risk of enforcement action.

16. 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.

17. Comments on Proposed Decision

The proposed decision of ALJ Thomas in this matter was mailed to the parties in accordance with Public Utilities Code Section 311.

18. Assignment of Proceeding

Clifford Rechtschaffen is the assigned Commissioner and Sarah R. Thomas, Nilgun Atamturk and Manisha Lakhanpal are the co-assigned ALJs in this proceeding.

Findings of Fact

1. PG&E's 2019 RPS Plan contains the required elements.
2. SCE's 2019 RPS Plan contains the required elements.
3. SDG&E's 2019 RPS Plan contains the required elements.
4. PG&E, SCE and SDG&E have adequate RPS-compliant generation for the next several years and need not hold a solicitation for additional resources in 2019.

[41] D.19-02-007 at 103.

5. The 2019 RPS Plans submitted by Bear Valley and Liberty did not follow the required format of the *2019 ACR*, or include a section describing how the 2019 RPS Plans are responsive to, and consistent with, LSE-specific policies and goals, statutes, and Commission policies.

6. With the exceptions noted above, the 2019 RPS Plans submitted by Bear Valley and Liberty contain the required elements.

7. PacifiCorp submitted an IRP on October 13, 2019 and an RPS supplement on November 8, 2019, too late for party comment.

8. The following CCAs' Plans contained adequate detail to meet the requirements of the *2019 ACR*: Apple Valley Choice Energy, Clean Power SF, East Bay Clean Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Solana Energy Alliance, and Sonoma Clean Power.

9. The following CCAs' Plans do not contain adequate detail to meet the requirements of the *2019 ACR*: City of Baldwin Park, City of Commerce, City of Hanford, City of Palmdale, City of Pomona, City of Santa Paula, Clean Power Alliance (LA County), Desert Community Energy, King City Community Power, Valley Clean Energy, Western Community Energy of Seven Cities.

10. The following CCAs do not demonstrate compliance with the long-term contracting requirement: City of Baldwin Park, City of Commerce, City of Hanford, City of Palmdale, City of Pomona, Desert Community Energy, King City Community Power, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, San Jacinto Power, Solana Energy Alliance, Valley Clean Energy Alliance, and Western Community Energy of Seven Cities.

11. The following ESPs submitted Plans that do not contain adequate detail to meet the requirements of the *2019 ACR*: 3 Phases Renewables; Agera Energy, LLC; American PowerNet Management, LP; Calpine Energy Solutions; Calpine PowerAmerica-CA, LLC; Commercial Energy of California; Constellation New Energy, Inc; Direct Energy Business; EDF Industrial Power Services (CA), LLC; Gexa Energy California, LLC; Just Energy Solutions; Liberty Power Holdings, LLC; Pilot Power Group, Inc.; Shell Energy; Tiger Natural Gas, Inc.; and EnerCal USA, LLC (dba YEP ENERGY).

12. Liberty Power Holdings, LLC, Mansfield Power and Gas, LLC, Palmco Power CA, Praxair Plainfield, Inc, Tenaska California Energy Marketing, LLC; and Tenaska Power Services Co. are ESPs that currently do not serve any retail load.

13. The RPS Plan filed by The Regents of the University of California contains adequate detail to meet the requirements of the *2019 ACR*.

14. Information enabling the Commission to compare the cost of overgeneration across large IOUs would be useful in the 2020 RPS Procurement Plans. SCE and PG&E did not include such information in their 2019 Plans.

15. PG&E's REC sales plan unduly burdens ratepayers.

16. SCE's proposal to use brokers and exchanges to sell RECs has been rejected by this Commission in the past because all such sales must be pre-approved. SCE has other adequate means of selling RECs that allow such pre-approval.

17. RPS has annual filing requirements and IRP has bi-annual filing requirements.

18. Incorporating proposed RPS plans with IRP plans could make both proceedings more efficient and less burdensome for staff, LSEs, and other stakeholders.

19. Changes in filing requirements should not negatively impact the cyclical review and approvals required for RPS and IRP.

20. Evidentiary hearings are not necessary in this proceeding.

Conclusions of Law

1. Based on PG&E's, SCE's and SDG&E's current stated RPS compliance positions, it is reasonable to approve PG&E's, SCE's and SDG&E's requests not to hold 2019 RPS solicitations.

2. 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 2019 RPS Procurement Plans, subject to the limitations set forth below.

3. The request for Energy Division to aggregate 2019 Plan data should be rejected.

4. Energy Division should initiate stakeholder workshops before filing of the 2020 draft RPS Procurement Plans to discuss whether there are redundancies with the Procurement Plans and Compliance Reports.

5. Public Utilities Code Section 399.13(b) requires long-term contracting for procurement towards Renewables Portfolio Standard requirements.

6. LSEs whose draft Plans do not demonstrate compliance with the long-term contracting requirement should bring them into compliance or detail a path to achieving compliance in their final Plans due on or before 30 days from the date of Commission issuance of this decision.

7. Any LSE that has not provided RPS cost information as required in the *2019 ACR* should provide such information in its final 2019 RPS Procurement Plan.

8. The request to transition cost quantification information required in LSEs' RPS Procurement Plans to a process in which LSEs compile cost information and submit it to the Commission via a standard data request response should be rejected.

9. IRP-generated curtailment values are too aggregated to provide guidance on individual LSEs' procurement decisions and LSEs should analyze the impact of oversupply events on their individual resource portfolios to inform their procurement decisions.

10. The recommendation to evaluate the actual project development success rate should be rejected due to the differences among different LSEs and for individual LSEs over time.

11. PG&E's REC sales framework should be approved with modifications. The pricing PG&E seeks should be rejected; PG&E may use its previously approved price floor methodology, or the methodology proposed by Cal Advocates.

12. As specified in D.11-12-052, the PCC classification determination can only be made after the actual energy is delivered and PG&E's proposal for the Commission to make a PCC determination when approving sales agreements should therefore be denied.

13. SCE's REC sales framework should be approved with modification.

14. SCE's REC sales volume should be limited on a per-vintage year basis.

15. The REC sales price floor methodology described in sections (i) and (iii) of its 2019 Plan, Appendix E, Section II should be rejected. SCE should apply the

limits in section (ii) of its methodology to section (i) of its draft 2019 Plan, Appendix E, Section II.

16. SCE's proposal to shift IOU REC sales to brokers and exchanges should be rejected.

17. SDG&E's REC framework should be approved with modification. As required by the *2019 ACR*, item 7, SDG&E should amend Section 9.D of its 2019 Plan to provide (1) a methodology for calculating maximum REC sales volumes for 2019, based on an analysis of its RNS, and (2) a detailed explanation of its REC sales pricing methodology.

18. If SDG&E seeks to assign Renewables Portfolio Standard contracts to a third-party buyer, SDG&E should do so via a Tier 3 Advice Letter.

19. It is reasonable to allow Liberty to use a Tier 1 Advice Letter process to execute contracts developed through an expedited short-term competitive process.

20. It is reasonable to exempt the six ESPs that do not serve load, Liberty Power Holdings, LLC, Mansfield Power and Gas, LLC, Palmco Power CA, Praxair Plainfield, Inc, Tenaska California Energy Marketing, LLC; and Tenaska Power Services Co., from filing RPS Procurement Plans since they do not serve retail load. The waiver should expire immediately if and when the foregoing entities resume serving load in California and thereby incur RPS procurement obligations.

21. It is not reasonable to exempt registered ESPs that do not serve load from the requirement to file RPS Compliance Reports and other required reports and submissions other than the RPS Procurement Plan. Hence, Liberty Power Holdings, LLC, Mansfield Power and Gas, LLC, Palmco Power CA, Praxair Plainfield, Inc, Tenaska California Energy Marketing, LLC; and Tenaska Power

Services Co. must continue to file RPS Compliance Reports and any other reports required by the Commission.

22. While D.19-02-007 and D.19-09-007 accepted incomplete CCA 2018 Plans, we stated in each decision that the Commission would not approve the Plans in 2019 unless they contain the missing information. Therefore, this decision does not accept as final the Plan of any CCA with missing data as shown in Table 5. The CCAs with missing data should furnish it with their final Plans, using the *2019 ACR* as a guide for what was required of each item in Table 5.

23. RPS sales frameworks should not jeopardize the value of RECs to ratepayers.

24. The Commission should take step to coordinate the RPS annual filing and the IRP proceeding.

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

26. The IOUs' joint TOD proposed methodology should be approved.

27. The original determination that hearings may be necessary should be changed because hearings were not necessary.

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 2019 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 with modification.

2. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company (IOUs) shall file Final 2019 Renewables

Portfolio Standard (RPS) Procurement Plans, modified in accordance with this decision, with the Commission within 30 days of the issuance date of this decision. The IOUs may issue solicitations to sell RPS volumes in accordance with the limitations of this decision 10 days after filing Final 2019 RPS Procurement Plans unless the IOU's amended RPS Procurement Plan is suspended by the Energy Division Director within the 10-day period.

3. Pursuant to the authority provided in Public Utilities Code Section 399.13(a)(1), the draft 2019 Renewables Portfolio Standard Procurement Plans filed by Bear Valley Electric Company and Liberty Utilities are conditionally accepted.

4. Bear Valley Electric Company and Liberty Utilities shall file Final 2019 Renewables Portfolio Standard Procurement Plans, modified in accordance with this decision, 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 2019 Renewables Portfolio Standard (RPS) Procurement Plans filed by the following Community Choice Aggregators (CCA) are accepted and deemed final: Clean Power SF, East Bay Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Solana Energy Alliance, and Sonoma Clean Power. Effective 35 days from this decision's issuance, any other new CCAs must file their RPS plans upon registering with the Commission or 90 days prior to delivering load, whichever event occurs first.

4. Pursuant to Public Utilities Code Section 365.1(c)(1), the 2019 Renewables Portfolio Standard (RPS) Procurement Plans filed by the following Community

Choice Aggregators (CCA) are not accepted or deemed final: City of Baldwin Park, City of Commerce, City of Hanford, City of Palmdale, City of Pomona, Clean Power Alliance (LA County), Desert Community Energy, King City Community Power, Valley Clean Energy, and Western Community Energy of Seven Cities. These CCAs shall include the missing information set forth in Table 5 with their final 2019 RPS Procurement Plans within 30 days of the issuance date of this decision.

5. City of Baldwin Park, City of Commerce, City of Hanford, City of Palmdale, City of Pomona, Desert Community Energy, King City Community Power, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, San Jacinto Power, Solana Energy Alliance, Valley Clean Energy Alliance, and Western Community Energy of Seven Cities shall demonstrate compliance or detail a path to achieving compliance with the long-term contracting requirement in their final 2019 Procurement Plans due within 30 days of the issuance date of this decision.

6. In their 2020 Renewables Portfolio Standard (RPS) Procurement Plans, the Community Choice Aggregators in column 3 of Tables 6 and 7 shall furnish information about their risk reduction and Minimum Margin of Procurement Strategies. This information shall contain additional detail beyond what was contained in their 2019 RPS Procurement Plans.

7. Pursuant to Public Utilities Code Section 365.1(c)(1), the 2019 Renewables Portfolio Standard Procurement Plan filed by The Regents of the University of California is accepted and deemed final.

8. Pursuant to Public Utilities Code Section 365.1(c)(1), the 2019 Renewables Portfolio Standard (RPS) Procurement Plans filed by the following Energy Service Providers (ESPs) are not accepted or deemed final: 3 Phases Renewables;

Agera Energy, LLC; American PowerNet Management, LP; Calpine Energy Solutions; Calpine PowerAmerica-CA, LLC; Commercial Energy of California; Constellation New Energy, Inc; Direct Energy Business; EDF Industrial Power Services (CA), LLC; Gexa Energy California, LLC; Just Energy Solutions; Liberty Power Holdings, LLC; Pilot Power Group, Inc.; Shell Energy; Tiger Natural Gas, Inc.; and EnerCal USA, LLC (dba YEP ENERGY). These ESPs shall include the missing information set forth in Table 9 with their final 2019 RPS Procurement Plans due within 30 days of the issuance date of this decision.

9. PacifiCorp's filings are not approved but will be the subject of a subsequent ruling and/or decision.

10. San Diego Gas & Electric Company (SDG&E) is authorized to not hold a 2019 Renewables Portfolio Standard (RPS) solicitation and shall indicate in its Final 2019 RPS Procurement Plan 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 during the time period covered by the 2019 solicitation cycle.) This authorization to not hold a solicitation only applies to the 2019 RPS solicitation cycle. SDG&E is authorized to conduct solicitations for the short-term sales of 5 years or less, of sales of RPS volumes if the sales agreement for any such sale is executed during the period after the Commission's adoption of this decision and prior to adoption of a subsequent RPS Plan. Deliveries under any such short-term sales agreement, including any agreement with a delivery term of 5 years or less, may commence at any time after the Commission's approval of the contract and continue until the expiration of the contract's term. SDG&E must seek Commission approval of short-term sales resulting from a solicitation or any bilateral transaction that both utilizes the *pro forma* sales agreement submitted

with its 2019 RPS Procurement Plan, showing any necessary modifications, and is executed after SDG&E receives bids for a sales solicitation resulting from its 2019 RPS Procurement Plan consistent with Decision (D.) 14-11-042's rules for expedited approval of short-term contracts, and D.09-06-050's rules regarding bilateral contracts. SDG&E may also engage in bilateral sales transactions that do not utilize the *pro forma* sales agreement submitted with its 2019 RPS Procurement Plan or that are not executed after SDG&E receives bids for a sales solicitation resulting from its 2019 RPS Procurement Plan, subject to the Commission's review and approval. SDG&E shall file a final 2019 RPS Procurement Plan with any updated solicitation materials.

11. Pacific Gas and Electric Company (PG&E) is authorized to not hold a 2019 Renewables Portfolio Standard (RPS) solicitation and shall indicate in its Final 2019 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 2019 solicitation cycle.) This authorization to not hold a solicitation only applies to the 2019 RPS solicitation cycle. PG&E is authorized to conduct solicitations for short-term sales of 5 years or less, of sales of RPS volumes if the sales agreement for any such sale is executed during the period after the Commission's adoption of this decision and prior to adoption of a subsequent RPS Plan. Deliveries may commence at any time after the Commission's approval of the contract and continue until the expiration of the contract's term. PG&E must seek Commission approval of short-term and long-term sales resulting from a solicitation or any bilateral transaction that both utilizes the *pro forma* sales agreement submitted with its 2019 RPS Procurement Plan, showing any

necessary modifications, and is executed after PG&E receives bids for a sales solicitation resulting from its 2019 RPS Procurement Plan consistent with Decision (D.) 14-11-042's rules for expedited approval of short-term contracts and D.09-06-050's rules regarding bilateral contracts. PG&E may also engage in bilateral sales transactions that do not utilize the *pro forma* sales agreement submitted with its 2019 RPS Procurement Plan or that are not executed after PG&E receives bids for a sales solicitation resulting from its 2019 RPS Procurement Plan, subject to the Commission's review and approval as established in D.09-06-050. PG&E shall file a final 2019 RPS Procurement Plan with any updated solicitation materials.

12. Southern California Edison (SCE) is authorized to not hold a 2019 Renewables Portfolio Standard (RPS) solicitation and shall indicate in its Final 2019 RPS Procurement Plan 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 2019 solicitation cycle.) This authorization to not hold a solicitation only applies to the 2019 RPS solicitation cycle. SCE is authorized to conduct solicitations for the short-term sales of 5 years or less, of sales of RPS volumes if the sales agreement for any such sale is executed during the period after the Commission's adoption of this decision and prior to the adoption of a subsequent RPS Plan. Deliveries under any such short-term sales agreement, including any agreement with a delivery term of 5 years or less, may commence at any time after the Commission's approval of the contract and continue until the expiration of the contract's term. SCE must seek Commission approval of short-term sales resulting from a solicitation or any bilateral transaction that both utilizes the *pro*

forma sales agreement submitted with its 2019 RPS Procurement Plan, showing any necessary modifications, and is executed after SCE receives bids for a sales solicitation resulting from its 2019 RPS Procurement Plan consistent with Decision (D.) 14-11-042's rules for expedited approval for short-term contracts and D.09-06-050's rules regarding bilateral contracts. SCE may also engage in bilateral sales transactions that do not utilize the *pro forma* sales agreement submitted with its 2019 RPS Procurement Plan or that are not executed after SCE receives bids for a sales solicitation resulting from its 2019 RPS Procurement Plan, subject to the Commission's review and approval of completed transactions, as established in D.09-06-050. SCE shall file a final 2019 RPS Procurement Plan with any updated solicitation materials.

13. 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 2019 Renewables Portfolio Standard solicitation or execute bilateral contracts, PG&E, SCE, or SDG&E shall first seek permission from this Commission in a manner consistent with the Commission's Rules of Practice and Procedure.

14. No later than March 31, 2020, unless extended by Energy Division due to scheduling constraints or availability of staff, Energy Division shall initiate stakeholder workshops before filing of the 2020 draft Renewables Portfolio Standard (RPS) Procurement Plans to discuss whether there are redundancies with the Procurement Plans and Compliance Reports.

The Director of Energy Division is directed to initiate a process to integrate the Renewables Portfolio Standard (RPS) annual filing with Integrated Resource Procurement (IRP) bi-annual filing, with the goal of improving efficiency for parties and staff without jeopardizing the current timelines, allocation of

Commission resources, or procedural efficiencies currently in place for the two proceedings. With this goal in mind, Energy Division is authorized to hold workshops, establish working groups, prepare a white paper or staff proposal, and take such other actions as the Director of Energy Division may deem necessary. The Director of Energy Division shall issue progress reports on a quarterly basis and shall complete a staff proposal based on the foregoing process no later than August 2020. Progress reports and the staff proposal shall be served on the service lists for both RPS and IRP proceedings.

15. Any Load Serving Entity that has not provided Renewables Portfolio Standard (RPS) cost information shall provide such information in its final 2019 RPS Procurement Plan.

16. The request to transition cost quantification information in Load Serving Entities' (LSE) Renewables Portfolio Standard Procurement Plans to a process in which LSEs compile cost information and submit it to the Commission via a standard data request response is rejected.

17. All Load Serving Entities shall analyze the impact of economic curtailment, overgeneration or oversupply events on their individual resource portfolios in their future Renewable Portfolio Standard Procurement Plans.

18. The joint Time of Delivery proposal (TOD) submitted by Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) on May 29, 2019 is approved. PG&E and SCE shall include in their final 2019 Renewables Portfolio Plans new informational-only TODs that are based on the most recent inputs that are available. SDG&E included the information with its filing. In future years' filings PG&E, SCE and SDG&E shall also provide workpapers to confirm there is

a high correlation between the public informational-only TOD factors and the confidential forecasts of PG&E, SCE and SDG&E.

19. Pacific Gas and Electric Company's (PG&E) Renewable Energy Credit sales framework is approved with modifications. The pricing that PG&E seeks is rejected; PG&E may use its previously approved price floor methodology or the methodology proposed by the Public Advocates Office.

20. Southern California Edison's (SCE) Renewable Energy Credit (REC) sales framework approved with modification. SCE's REC sales volume is limited to a per-vintage year basis and SCE's REC sales price floor methodology is rejected. The limits of SCE's REC sales price floor methodology described in sections (i) and (iii) of its Appendix E, Section II of its 2019 Renewable Portfolio Standard Plan is rejected. SCE shall apply the limit in section (ii) of its methodology to section (i), as described in its draft 2019 Plan, Appendix E, Section II.

21. San Diego Gas & Electric Company's (SDG&E) Renewable Energy Credit (REC) sales framework is approved with modification. SDG&E shall amend Section 9.D of its 2019 Plan to provide (1) a methodology for calculating maximum REC sales volumes for 2019, based on an analysis of its Renewable Net Short, and (2) a detailed explanation of its REC sales pricing methodology, including a target price and price floor.

22. If San Diego Gas & Electric Company (SDG&E) seeks to assign Renewables Portfolio Standard contracts to a third-party buyer, SDG&E shall do so via a Tier 3 Advice Letter.

23. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall seek the Commission's approval through a Tier 3 Advice Letter for any significant modification to any

procurement contract for Renewables Portfolio Standard-eligible resources that was approved by the Commission.

24. Liberty Utilities is authorized to hold a 2019 Renewables Portfolio Standard (RPS) solicitation and shall seek Commission approval of any authorized procurement via the processes approved in Decision (D.) 03-06-071, D.09-06-050, D.14-11-042, and Public Utilities Code Section 399.14.

25. For 2020, Community Choice Aggregators and Electric Service Providers (ESPs) shall include more granular information regarding planning in the next annual procurement plan cycle, beyond a general statement that they will comply with the Renewables Portfolio Standard requirements and upcoming long-term procurement requirements.

26. Liberty Power Holdings, LLC, Mansfield Power and Gas, LLC, Palmco Power CA, Praxair Plainfield, Inc, Tenaska California Energy Marketing, LLC; and Tenaska Power Services Co. are not required to file Renewables Portfolio Standard Procurement (RPS) Plans for 2020. The requirement to file RPS Compliance Reports and other RPS required submissions remains unchanged. The waiver will expire immediately if and when the foregoing entities resume serving load in California and thereby incur RPS procurement obligations.

27. In their 2020 Renewables Portfolio Standard (RPS) Procurement Plans, Pacific Gas and Electric, Southern California Edison and San Diego Gas and Electric shall quantify any direct cost impacts resulting from incidences of overgeneration and associated negative market prices to better inform their strategy in managing incidences of curtailment. The quantified impact shall include the amount paid for generating during times of negative pricing for all RPS-eligible resources.

28. All motions for confidentiality as to the 2019 Renewables Portfolio Standard Plans are granted.

29. Rulemaking 18-07-003 remains open.

This order is effective today.

Dated ______________________________, at San Francisco, California.

APPENDIX A

APPENDIX A

2019 RPS Plans
Acronym List

Acronym	Term
2018 RPS Plan	2018 Renewables Portfolio Standard Procurement Plan
AAEE	Additional Achievable Energy Efficiency
AAPV	Additional Achievable Photovoltaics
AB	Assembly Bill
ACR	*Assigned Commissioner and Assigned Administrative Law Judge's Ruling Identifying Issues and Schedule of Review of 2018 Renewables Portfolio Standard Procurement Plans* issued June 21, 2018
ADNU	Area Delivery Network Upgrades
ADS	Automated Dispatch System
AL	Advice Letter
ALJ	Administrative Law Judge
API	Application Programming Interface
ASC	Accounting Standards Codification
AVCE	Apple Valley Choice Energy
BioMAT	Bioenergy Market Adjusting Tariff
BioRAM	Bioenergy Renewable Auction Mechanism
BNI	Binding Notice of Intent

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 Aggregators/Aggregation
CEC	California Energy Commission
CED	California Energy Demand
CEQA	California Environmental Quality Act
COD	Commercial Operation Date
CP	Compliance Period
CPA	Clean Power Alliance
CPCN	Certificate of Public Convenience and Necessity
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CR	Community Renewables
D.	Decision
DA	Direct Access
DAC	Disadvantaged Communities
DBE	Diverse Business Enterprise

DCE	Desert Communities Energy
DER	Distributed Energy Resource
DERP	Distributed Energy Resource Provider
DG	Distributed Generation
DLAP	Default Load Aggregation Point
DNA	Delivery Network Upgrades
ECO	East County
ECR	Enhanced Community Renewables
EE	Energy Efficiency
EJ	Environmental Justice
ELCC	Effective Load Carrying Capacity
EPC	Engineering, Procurement, and Construction
ERR	Eligible Renewable Resource
ERRA	Energy Resource Recovery Account
ESP	Electric Service Provider
EV	Electric Vehicle
FCDS	Full Capacity Deliverability Status
FERC	Federal Energy Regulatory Commission
FFO	Funds From Operations
FIT	Feed-In Tariff

GAM	Green Allocation Mechanism
GCOD	Guaranteed Commercial Operation Date
GHG	Greenhouse Gas
GIS	Geographic Information System
GO	General Order
GRC	General Rate Case
GT	Green Tariff
GTSR	Green Tariff Shared Renewables Program
GWh	Gigawatt-hour
HVDC	High Voltage Direct Current
ID&WA	Irrigation District and Water Agency
IE	Independent Evaluator
IEPR	Integrated Energy Policy Report
IID	Imperial Irrigation District
IOU	Investor-Owned Utility
IPP	Independent Power Producer
IR	Interconnection Request
IRP	Integrated Resource Plan
ITC	Investment Tax Credit

IV	Imperial Valley
kWh	Kilowatt-hour
LCBF	Least-Cost Best-Fit
LCE	Lancaster Choice Energy
LCR	Local Capacity Requirement
LDNU	Local Delivery Network Upgrades
LOLP	Loss of Load Probability
LSE	Load-Serving Entity
LTPP	Long-Term Procurement Plan
MW	Megawatt
MWh	Megawatt-hour
NBC	Non-Bypassable Charge
NEPA	National Environmental Policy Act
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
NU	Network Upgrades

OIR	Order Instituting Rulemaking
OP	Ordering Paragraph
OSHA	Occupational Safety and Health Administration
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
PPTA	Power Purchase Tolling Agreement
PQR	Procurement Quantity Requirement
PRG	Procurement Review Group
PRIME	Pico Rivera Innovative Municipal Energy
PRP	Preferred Resources Pilot
PTC	Production Tax Credit
PTO	Participating Transmission Owner
PURPA	Federal Public Utility Regulatory Policies Act of 1978

PV	Photovoltaic
PV RAM	Photovoltaic Renewable Auction Mechanism
QF	Qualifying Facility
R.	Rulemaking
RA	Resource Adequacy
RAM	Renewable Auction Mechanism
REC	Renewable Energy Credit
ReMAT	Renewable Market Adjusting Tariff
RFO	Request for Offers
RFP	Request for Proposal
RICA	Renewable Integration Cost Adder
RMEA	Rancho Mirage Energy Authority
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
S&P	Standard and Poor's

SB	Senate Bill
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SJP	San Jacinto Power
SONGS	San Onofre Nuclear Generating Station
SONS	Stochastically-Optimized Net Short
SPVP	Solar Photovoltaic Program
SWPL	Southwest Powerlink
TE	Transportation Electrification
TOD	Time Of Delivery/Day
TOU	Time of Use
TPD	Transmission Plan Deliverability
TPP	Transmission Planning Process
TRTP	Tehachapi Renewable Transmission Project
TURN	The Utility Reform Network
TWRA	Tehachapi Wind Resource Area
UOG	Utility-Owned Generation
VIE	Variable Interest Entities
VMOP	Voluntary Margin of Procurement (PG&E); Voluntary Margin of Over-Procurement (SDG&E and SCE)

WECC	Western Electric Coordinating Council
WREGIS	Western Renewable Energy Generation Information System

(END OF APPENDIX A)

APPENDIX B

APPENDIX B

List of all IOUs, SMJUs, CCAs, and ESPs required
to file 2019 RPS Procurement Plans

LSE	LSE type	Filing Notes
Bear Valley Electric Service	Small IOU	
Liberty (CalPECO)	Former MJU	
PacifiCorp	MJU IOU	
PG&E	IOU	
SCE	IOU	
SDG&E	IOU	
Apple Valley Choice Energy	CCA	
City of Baldwin Park	CCA	
City of Commerce	CCA	
City of Hanford	CCA	
City of Palmdale	CCA	
City of Pomona	CCA	
City of Santa Paula	CCA	Delayed implementation, so no longer needs to file
Clean Power Alliance (LA County)	CCA	
CleanPowerSF (San Francisco CCA)	CCA	
Desert Community Energy	CCA	
East Bay Clean Energy	CCA	
King City Community Power	CCA	
Lancaster Choice Energy	CCA	
Marin Clean Energy	CCA	
Monterey Bay Community Power	CCA	
Peninsula Clean Energy	CCA	

Pico Rivera Innovative Municipal Energy	CCA	
Pioneer Community Energy	CCA	
Rancho Mirage Energy Authority	CCA	
Redwood Coast Energy Authority	CCA	
San Jacinto Power	CCA	
San Jose Clean Energy	CCA	
Silicon Valley Clean Energy	CCA	
Solana Energy Alliance	CCA	
Sonoma Clean Power	CCA	
Valley Clean Energy (City of Davis)	CCA	
Western Community Energy of Seven Cities	CCA	
3 Phases Renewables	ESP	
EDF Industrial Power Services (CA), LLC	ESP	
Tiger Natural Gas, Inc.	ESP	
EnerCal USA, LLC (dba YEP ENERGY)	ESP	
Liberty Power Holdings LLC	ESP	Granted provisional waiver to not file RPS Plan in 2018 Plans decision on new CCAs (D.19-09-007)
American PowerNet Management, LP	ESP	
Just Energy Solutions	ESP	
Constellation New Energy, Inc	ESP	
Agera Energy, LLC	ESP	
The Regents of the University of California	ESP	
Calpine Energy Solutions	ESP	
Liberty Power Delaware LLC	ESP	Granted provisional waiver to not file RPS Plan in 2013 Plans decision

Pilot Power Group, Inc.	ESP	
Mansfield Power and Gas, LLC	ESP	Granted provisional waiver to not file RPS Plan in 2017 Plans decision
Palmco Power CA	ESP	Granted provisional waiver to not file RPS Plan in 2018 Plans decision
Shell Energy	ESP	
Praxair Plainfield, Inc.	ESP	Granted provisional waiver to not file RPS Plan in 2013 Plans decision
Commercial Energy of California	ESP	
Tenaska California Energy Marketing, LLC	ESP	Granted provisional waiver to not file RPS Plan in 2017 Plans decision
Tenaska Power Services Co.	ESP	Granted provisional waiver to not file RPS Plan in 2017 Plans decision
Direct Energy Business	ESP	
Calpine PowerAmerica-CA, LLC	ESP	
Gexa Energy California, LLC	ESP	

(END OF APPENDIX B)